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CALIFORNIA ENERGY COMMISSION

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Electricity and Natural Gas

Demand Forecast

CALIFORNIA ENERGY COMMISSION

ROSENFELD HEARING ROOM – FIRST FLOOR

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, AUGUST 3, 2017

10:00 A.M.

Reported by:

Susan Palmer

APPEARANCES

COMMISSIONERS

Robert Weisenmiller, Chair

Andrew McAllister, Commissioner

Janea Scott, Commissioner

ENERGY COMMISSION STAFF

Heather Raitt, Project Manager

PRESENTERS

Chris Kavalec, Energy Commission

Aniss Bahreinian, Energy Commission

Scott Shepard, Navigant Consulting (Via WebEx)

Asish Gautam, Energy Commission

Lynn Marshall, Energy Commission

Hongyan Sheng, Southern California Edison

Tim Vonder, San Diego Gas & Electric

Nate Toyama, Sacramento Municipal Utility District

AGENDA

AGENDA

P R O C E E D I N G S

10:05 A.M.

SACRAMENTO, CALIFORNIA, THURSDAY, AUGUST 3, 2017

MS. RAITT: All right, we'll go ahead and get started. Good morning. Welcome to today's IEPR Workshop on the California Energy Demand for 2018 through 2028 -- excuse me, sorry -- the forecast -- we're having a Workshop on the Preliminary Forecast Demand for 2018 through 2028.

I'm Heather Raitt, the Program Manager for the IEPR.

Normal housekeeping items.

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

Our workshop today is being broadcast through WebEx, so parties will be recorded. We will be posting the audio recording in about a week and a written transcript in about a month.

At the end of the workshop today, we will have an opportunity for public comments. We'll

limit those to three minutes per person. You can go ahead and, if you're in the room, fill out a blue card and give it to me, if you'd like to comment at the end of the day.

And then also on WebEx, just go ahead and raise your hand if you have a comment at the end of the day. And then we'll also open up the phone lines for folks who are on the phone.

Materials for this meeting are available at the entrance and on our website. And written comments are welcome and due August 24th.

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

CHAIR WEISENMILLER: I want to thank everyone for being here today and, obviously, the staff activity, putting this together.

So one of the central things the Energy Commission does is demand forecasting. And this is a critical step in the process which we now and the end of the year when we're a adopting Demand Forecast, in terms of putting out preliminary numbers. Obviously, these are, by definition, preliminary. So we're going to be looking for input from folks on how to do better, and look forward to getting a pretty lively set

of feedback.

Now, having said that, we also have been around long enough to understand that the documents are just coming out, so much of the feedback is going to be in the written comments. But at least this is a good chance for the staff to make the presentation for we Commissioners to ask some questions, get some public comment or questions. And then, again, looking forward to everyone digging in deeply and providing more detail and feedback later.

So, again, thanks for being here.

COMMISSIONER SCOTT: Good morning. This is Commissioner Scott. I don't have anything to add to that, but I will just echo it.

MS. RAITT: Great. So our first speaker is Chris Kavalec from the Energy Commission.

MR. KAVALEC: Good morning. I'm Chris Kavalec from the Energy Assessments Division. Before I get started with my presentation, I wanted to say a couple of things about the agenda.

In every forecast we have one factor that draws the most interest, that becomes the most critical in the forecast. And during the

recession it was the economy. Other years it's been efficiency. This year it's the combination of electric vehicles and photovoltaic adoptions. The reason for that is that it makes the most difference in terms of our forecasts this year versus our 2016 forecast, and our forecast versus the utilities' own forecasts.

So we're going to have presentations on each of those, of course. And I've asked Aniss Bahreinian to give a high-level summary of the way that we forecast electric vehicles, as compared to how other forecasts are done.

And we're also lucky enough to have Nagivant making a presentation over the phone right after that, discussing their forecast methods, which were adapted by Edison for their Electric Vehicle Forecast, which happens to be a lot higher than ours. So we'll learn a little bit, hopefully, about the different types of methodologies and forecasts that are out there for electric vehicles.

We're also going to hear, along with our forecasts -- forecasted rate scenarios that we're using in this preliminary version, we're going to hear an update on the Residential TOU Analysis,

which will be an important factor in our hourly load forecasts that we're planning to do for the Revised Forecast.

And in the afternoon, of course, we'll have presentations on the individual planning areas, the five major planning areas. I don't expect that to take too long, number on, because our -- the -- a couple of the forecasts are very similar, so there's not a lot to talk about in terms of differences.

And the other thing is that the IOUs are ahead of us when it comes to the analysis of what we call the peak shift, the impacts of moving the peak hour to later in the day. Their peak forecasts incorporate the peak shift, while ours does not yet. That won't be until the Revised Forecast. So it's hard to make a comparison between our peak forecasts and their peak forecasts. Okay.

Before I get to the forecasts, I wanted to talk a little bit about recent trends in terms of statewide sales. Then I'm going to talk about methods, assumptions and inputs, giving a high-level summary, then summarize our statewide results, and then talk about next steps and what

we're planning to do for the Revised Forecast. Okay.

So here's a graph of statewide electricity retail sales since 1990. You'll notice the jump in the late '90s with the tech boom, followed by the electricity crisis in 2001, along with the recession. And relatively steady growth until we reach 2008 and we have another recession. You can see that clearly there. And then since 2012, electricity sales have been flat or declining.

So the question was, at least for me, during the recession, how was electricity demand and sales going to respond as the California economy began to recover? Was it going to be like past episodes where we have a sustained period of growth and demand after a recession? Or were we doing enough with our demand modifiers, efficiency and so on, to prevent that sort of bounce-back effect from fully happening this time?

So what I did here in this graph was I took the historical trend from 1990 to 2007 and sort of plunked it down at the bottom of the recession in 2010. And so this is -- and that's

the green-dotted line. So this is basically showing, if out of the recession we grew at a historical average rate, what would sales have looked like?

So you see in the first two years there where the historical trend is matching the sort of bounce-effect that's happening after the recession, but then after 2012 these diverge. And so in 2016, we have a pretty healthy, what I call a gap there between what sales would have been had we followed the historical trends from 2010 on and what we actually saw in 2016.

So let's see what's going on here, some of the obvious things, for me at least, were a big increase in self-generation, particularly PV. And so what we call the residential PV boom began really in 2012. So we went from a few hundred megawatts installed capacity to around 3,300 by 2016.

Our intensified, continually intensified energy efficiency efforts, as well as market transformation -- I guess an example of that would be in the case of light bulbs where customers are now pretty comfortable with the high-efficiency lighting. And it doesn't, in

most cases, require an incentive anymore to get someone to buy an LED light, because customers have become comfortable with them, they're happy with the features, so it doesn't take incentives to keep that going.

We've had some significant rate increases for customers from 2012 to 2016, particularly in the case of PG&E, San Diego, and LADWP. So even though the tiers for those rates have flattened, overall the average rates have gone up, especially in those three cases.

A lower population, well, we've now dipped below one percent growth a year, whereas most of the 1990 to 2007 period you have, you know, 1.5 percent, 1.7 percent some years. The overall average was around 1.2 percent. And really, the only other time that happened in this historical period is back in the mid '90s when we had the base closures, the faltering economy, a housing bubble and so on. The population growth was very low in California in the mid '90s. But since then it's gone back up to, you know, above one percent a year, until recently where we're less than one percent a year. And the difference between now and back in the mid '90s is that DOF

and others project this below one-percent growth per year to continue.

Okay, back to our forecast, what we call California Energy Demand 2018 to -- that should be 2018 to 2028 Preliminary Baseline Forecast, and we call that CED 2017 Preliminary, for short. The 2017 is in there because that's the year we're working on the forecast.

Important methods, assumptions and inputs that go into our forecast.

First of all, when we forecast, we forecast at the planning-area level. And these are our eight planning areas for electricity, the IOUs. We have one group in Northern California that represents the utilities that are not part of CAISO, which we call Northern California Non-California ISO, or NCNC, which the biggest utility in that group is SMUD. LADWP, a couple of the smaller utilities, Imperial, Burbank, Glendale. And then Valley Electric Association, which is really small but it's its own transmission access charge area within CAISO, so we keep it separate.

We also forecast for natural gas, and these are the natural gas planning areas, the big

three, plus the rest, it's the smaller ones grouped into what we call other.

And we like to show this impressive looking graph to intimidate stakeholders into not arguing with the forecast, but it never works. So at the top here we have our economic and demographic drivers behind the forecast. And, of course, we're calibrating and scaling to actual historical electricity and natural gas consumption.

In the middle of the graph there we have our traditional sector models that we've used for a long time, with residential and commercial being the most complicated, and those are full end-use models.

Along the sides there we have what's becoming more and more important in our forecast, on the right-hand side in the yellow box, self-generation. We have models to predict self-generation including PV adoption.

And as we'll talk about today, we have separate models to project electric and natural gas vehicles on the left-hand side there.

So we aggregate this all up into a summary model. And then consumption projections

at the end-use level are sent to our peak model where load shapes are applied and we develop a peak for each year. This will change now, as I alluded to earlier, because -- or we'll have an important addition after this forecast as we start doing -- projecting hourly loads. What we're projecting now is strictly annual totals for sales, consumption and peak demand.

As usual, we do three baseline cases, high demand, low demand and mid demand, to try to capture the uncertainty around any forecast that you do. So a high-demand case will have the higher economic and demographic growth, more climate change impacts, higher projections for electric vehicles, lower electricity rates, and less self-generation, leading to higher sales.

And the low-demand case is the opposite of that, lower econ demo projections and so on.

And then we have the mid-demand case, the most important one. It ends up getting used for planning purposes. That has assumptions falling in between the high- and the low-demand cases.

For our economic assumptions, we're using scenarios developed by Moody's. Our mid-demand case, as usual, is the Moody's, what they call

their baseline scenario. In the low-demand case, we have their scenario referred to as lower long-term growth. The reason we use that one, we choose that among their low scenarios, is that the other low scenarios have less growth in the short run, but by the end of the ten-year period, they revert back to the baseline case. So it doesn't give us a lot of difference ten years out.

For this forecast, we asked Moody's to develop a high, a special high-demand case, which we refer to as the custom high scenario. And the reason we did that is that in the past we've used Global Insight's, what they call their optimistic case for the high-demand scenario.

But the problem was always inconsistency between Moody's and Global Insight. So we might end up with a higher commercial forecast in a high case but a lower industrial forecast, just because of the difference in projections between Moody's and Global Insight. And the problem with Moody's, always before, was their high-demand scenarios were always very close to the mid-demand case. So we asked them to develop a more aggressive high-demand case specifically for us,

so that's what we're using.

Overall, the drivers themselves don't make a lot of different relative to our last adopted forecast. There's not a big difference among the economic drivers, compared to what we used last year. The action, as I referred to earlier this year in the forecast is really on the EV side and self-generation.

A comparison of our economic assumptions by demand case with our three new demand cases and the 2016 forecast, personal income, comparing the two mid cases, the third column and the fifth column, a little bit lower personal income growth, a little bit lower population and households projections, a little bit higher projections for manufacturing output, and then commercial employment which drives the forecast for the commercial sector, practically identical between our new mid case and the 2016 mid case.

Okay, turning to energy efficiency, compared to our last forecast, we're incorporating new programs, 2016 and 2017 utility program savings for both the IOUs and the POUs. Those were included in the 2016 forecast, but were part of additional achievable energy

efficiency, so they were not part of what we call the baseline case. So just to make that clear, what we're presenting today is what we call a Baseline Forecast in that it doesn't include additional achievable energy efficiency. That will be included in the Revised Forecast.

We're also incorporating standards that weren't in the Baseline Forecasts before, the 2016 Title 24 updates. As I mentioned, we will have additional achievable energy efficiency as a tool to develop what we call a Managed Forecast by the time of the Revised Forecast for both IOUs and POUs.

We also have some efficiency savings beyond our traditional AAEE being developed by the Efficiency Division in support of SB 350. So these would be sort of, quote, nontraditional efficiency savings that come from other means besides utility programs and our Building and Appliance Standards. So depending on the progress that they make with these additional efficiency savings and how solid we think the savings estimates are, these could be included in our forecast as an additional source of AAEE, so we'll see how that goes.

Other key assumptions and inputs will be discussed in upcoming presentations this morning, electric rates, light-duty electric vehicles, and self-generation featuring PV.

Other assumptions and inputs that go into our forecast, the impact of climate change, we get temperature scenarios from Scripps Institute of Oceanography that we use to develop trends for annual maximum temperatures and cooling degree days and heating degree days. And we apply that to regression models to get -- to estimate the impact of a warming climate on electricity, natural gas consumption, and electricity peak.

We weren't able to get the newest scenarios in time for this Preliminary Forecast. So what we're using for this, for now, is what we used in 2015 as a placeholder. But for the Revised Forecast, we'll be incorporating the newest temperature scenarios.

Anyway, the impact of climate change in our Preliminary Forecast gives around, in the mid case, an additional 800 gigawatt hours by 2028, and an additional 650 megawatts in annual peak demand by the end of the forecast period.

We include, aside from electric vehicles,

other transportation electrification, which includes -- including high-speed rail. This also includes things like port electrification, forklifts, truck refrigeration units, other applications suited to electrification. And our analysis, together with our consultant, estimates an impact from these other sources of transportation electrification of around 850 gigawatt hours by the end of the forecast period statewide.

Load modifying demand response, there is some demand response programs that we include on the demand side, and those include critical peak pricing, peak time rebates, time of use, and permanent load shifting. The rest are on the supply side and get incorporated when resource planning is done. So this is actually a pretty small part of the total DR, but that's what goes on the demand side. And, of course, we need natural gas rates, both for our natural gas forecasts, and also for developing our electricity rate scenarios.

Some of the statewide results, first looking at baseline, again, no AAEE, electricity consumption, we have our three new cases, purple,

dark blue and green, high, mid and low, respectively. And then we show the mid case from our last forecast in 2016, which is in red.

So we start out lower than we did in the 2016 forecast because we've added a lot of efficiency program impacts in the first couple of years that weren't there in the 2016 forecast. After that, growth is similar, but the new mid case stays below the old mid case because of the addition of the 2016 Title 24 updates, as well as a slightly lower electric vehicle forecast this time in the mid case.

In California, we always like to talk about our record in terms of electricity consumption per capita. You see, particularly since, in the last few years, it's been pretty flat or declining, but overall, relatively flat since 1998, at least compared to the nationwide consumption per capita, and we project it to remain relatively flat in the first part of the forecast period. But then as we add more and more electric vehicles, it starts to hike up a little bit. And in the high demand case, it's increasing because of the higher economic and demographic growth, it's increasing, basically,

throughout the forecast period. And this will, of course, change once we incorporate additional achievable energy efficiency. They won't increase by nearly as much.

As we will talk about later today, we have a higher forecast for self-generation, particularly for photovoltaics. And that creates the difference you see here between sales in the mid demand cast last time and the mid demand case for this Preliminary Forecast, so that's the red and the blue. Again, you see the distance between the two. That's coming from higher self-generation, which reduces sales.

COMMISSIONER MCALLISTER: Chris, can I ask a clarifying here?

So, you know, you mentioned all the doubling activity. Maybe there's more to come on this, I'm not sure. But -- so we do have the sort of two Type 2 efforts going on, complementary efforts going one, one to quantify sort an AAEE tradition, and then the other sort of beyond that which are, you know, a little more market oriented. You can call them speculative. But I think, you know, if we get the kind of market shifts that we're working for, then they

could very well prepare. They're just not as predictable in terms of, you know, a modeling construct. So, you know, we have the Energy Analysis Division working on the AAEE piece, the Efficiency Division working on the above, you know, program piece.

In terms of incorporating that second piece of efficiency into at least a scenario of the forecast, what's your thinking on that, you know, sort of a doubling-compliant forecast, if you will?

MR. KAVALEC: Although we don't know whether it's going to reach doubling; right?

COMMISSIONER MCALLISTER: I guess that's my question, really, is that, you know, we're talking about sort of the sum of the two efforts is sort of almost a doubling under roughly a status quo approach with some assumptions underneath it. There is a gap between where we think we'll kind of get on the natural in a true doubling. Obviously, our task over the next, you know, 13 years is to figure out where to get those new savings and actually get to doubling.

But I guess a scenario that sort of expresses what a doubling would look like, if we

get there, kind of seems like it would be a helpful reference to have, even if it doesn't sort of follow -- I mean, it's not going to follow -- it's not going to come naturally out of a model, you know, okay, you change these assumptions, you get to doubling.

But I guess, you know, I'm kind of wondering what your toolkit is to produce something like that, possibly as kind of a reference, so the world would know, okay, here's roughly what the, you know, net demand, the managed forecast would look like if we achieved our doubling goals?

MR. KAVALEC: So two parts to that. Creating a doubling scenario is pretty simple when you're not also doing an analysis of all the component parts that get you to that doubling.

COMMISSIONER MCALLISTER: Yeah. It's like a macro.

MR. KAVALEC: Yeah. It's pretty easy to go in and say, okay, we're going to double the efficiency, here's what the forecast looks like. So that could certainly be a scenario we could do.

But in terms of, let's say, the mid case,

how much of that gets incorporated, as I said, depends on how much progress is made in that effort and how solid we think those savings estimates are. So if, you know, if -- we can include some portion of them, depending on the analysis that's done.

COMMISSIONER MCALLISTER: Yeah. I mean, I'm actually, really, I'm enjoying this process of trying to figure out how we're going to get to doubling because it's kind of forcing everybody to be real, you know, and sort of, okay, what's going to -- in a way, it's just surfacing the long-term tension that we've had between sort of the optimists and the skeptics about, you know, okay, well, gosh, we really -- you know, California does efficiency, we're going to do it, on the one hand and, well, is it really showing up and, you know, we need absolute proof on the other hand.

And so I think it's actually healthy to have that conversation. And really, I guess, sort of that bookend of, you know -- I mean, it doesn't have to be a bookend, maybe we exceed the doubling, I don't know, but having that expressed. And then, you know, the overall

narrative being, look, he's what our goal is. It's a big, gnarly goal and we're doing our best to get there.

In the -- you know, however, if we think about sort of the way we understand how efficiency percolates and gets -- you know, investments happen and efficiency actually takes place, you know, here's our best guess as to sort of on the natural, what we would get. And having that narrative to be able to tell, I think is a really helpful thing. I mean, these are things that the staff, the respective staffs are putting together and I think are going to help us there. I just want to make sure that kind of gets to its logical expression visually in the forecast so that we can, you know, really keep people's eyes focused on what's necessary to actually increase the probability that we'll get or exceed the goal.

So anyway, we can talk about this offline. But I think it's really important at this juncture, since SB 350 is so central to what we're doing this year, and we're really, you know, taking off with that effort, so this helps us construct the narrative that's going to keep

it sort of relevant and positive for the next decade, so --

MR. KAVALEC: Yeah.

COMMISSIONER MCALLISTER: -- appreciate that.

MR. KAVALEC: Much more discussion to come, obviously.

We also want to be clear, though, that when we do a scenario like this, when we assume a goal is met, we don't treat that as -- or we shouldn't treat it as a forecast, we should treat it as a scenario.

COMMISSIONER MCALLISTER: Yeah. Yeah. I got it

MR. KAVALEC: Okay.

COMMISSIONER MCALLISTER: That's exactly my point, is that we -- a scenario that sort of expresses that goal would be, I think, really helpful to have, as long as we're clear about what it is.

MR. KAVALEC: Similar to sales, we see the impact of additional PV in our 2017 forecast, compared to 2016. So you see the gap there between the red, the mid from last time, and the dark blue, the mid from this time.

Then this is, to be clear, this is the baseline non-coincident peak, meaning it's the simple sum of all the individual planning areas coincident peaks that may happen at different hours.

We also do a natural gas forecast, which we don't usually give as much attention to because we've been more interested in electricity issues in the last few years. But we do a natural gas demand forecast with the same basic models we use for electricity.

I'm not going to talk too much about it today because we have an upcoming workshop on natural gas where I'm going to provide some more details of our end-user forecast. But I just wanted to show the statewide forecast and make one point about natural gas compared to electricity, and that is how weather sensitive natural gas demand is because heating is such an important end-use for natural gas. So changes in weather, hotter or warmer years are going to make a big difference in total natural gas consumption.

So looking at history versus our forecast, you see that big jump in 2016, going

into the forecast period. And the reason for that is 2016, as well as 2015 and 2014, were very warm years with very few heating degree days. Once we get to the forecast period, we go back to, quote, normal or average weather, which means a lot more heating degree days, which means a jump upward in natural gas consumption. So that's what's going on there.

Here's the sum total of committed efficiency program savings. Those are efficiency program savings that are included in our baseline forecast. So this includes the IOUs, as well as all the POUs. And you can see that we're reaching around 19,000 gigawatt hours in 2017, the accumulation of all our program savings, which amounts to about a six-and-a-half percent reduction in consumption.

And then you see the big drop-off after that. And the reason for that is we're not adding new first-year savings after 2017 because we're only including committed program savings. And the drop-off is steeper than it otherwise would be because there are still a lot of lighting programs in the committed programs, efficiency programs, which don't have a long

expected useful life. So once that EUL is -- you've reached the EUL, you're losing all those lighting savings and it goes down pretty quickly. And this would look a lot different once we incorporate the program savings from AAEE and other sources for our Revised Forecast.

Light-duty electric vehicle electricity consumption, we project around 1.7 million vehicles on the road by the end of the forecast period.

Here you see our three new forecasts versus what we projected in the mid case in 2016. You'll notice the difference in shape. And what's going on there is that in 2016, we were using the previous compliance scenario developed by CARB, the compliance scenario to meet the ZEV mandate. And in that compliance scenario, it required a lot more electric vehicles. And therefore, we had to kind of torture the model to increase the rate of electric vehicle adoptions so that we could match ZEV, per the compliance case as it was at the time.

Since then, another compliance scenario has been done. And a lot higher range has been observed and was assumed in the new compliance

case. And the higher the range of an individual vehicle, electric vehicle, the more credit that it gets towards ZEV. So this means you require less electric vehicles in the new version of the compliance case and our forecasts at this time, using that, the ZEV mandate because it requires less vehicles. So that's why you see the straight lines versus the curved line to match the ZEV in 2016.

Self-generation impacts, you see the big difference by the end of the forecast period between our new forecasts and what we did in 2016, and that difference is coming almost exclusively from a higher PV forecast, which we'll talk about more in a few minutes. But by the end of the forecast period the two mid cases differ by around 1,200 megawatts.

Okay, so that's a high-level summary of our results. And this afternoon we'll go into more detail with the planning area forecasts.

But now I want to talk about what we're thinking about, what we're planning for our Revised Forecast, which we'll get started on very soon and will be released late in the fall or early in the winter.

So for efficiency, we are, as I mentioned, developing -- in the middle of developing AAEE estimates for the IOUs with the help of CPUC/Navigant. And this time, as we had last time, we're also going to develop an 8760 set of load impacts for AAEE for incorporation into our hourly load forecasting model. We're going to develop, as I said, AAEE for as many POUs as we have time for during this cycle. And as we talked about earlier, if feasible, incorporate other efficiency savings provided by the Efficiency Division that goes beyond our traditional AAEE.

And as far as PV impacts, in 2019 we have an update of Title 24 which is -- one of the purposes is to address the zero-net energy requirement. On both the efficiency side and on the PV side. So it has certain requirements for both efficiency and PV. Now the 2019 Title 24 in AAEE terms is considered uncommitted because it hasn't yet been implemented.

So I propose that we use the same principle for the PV -- additional PV impacts attributable to the 2019 Title 24 update, meaning that our baseline forecast will include a sort of

unconstrained forecast for PV adoption. And then the managed forecast would include an additional chunk of PV that comes from the implementation of the 2019 Title 24. So it would be in two pieces, just like we have efficiency in two pieces, an uncommitted and a committed version, so --

COMMISSIONER MCALLISTER: I think that makes sense. And, you know, just I'm sure you're already doing this but just to sort of make it clear, as, you know, we have an open rulemaking and a pre-rulemaking phase on the Title 24 update for 2019. And so the efficiency requirements, I think, are something that, you know, we've done it for many cycles and it's sort of more understood. And so I think you can probably have narrower bands of uncertainty around that just from the get-go, starting now. I think it's pretty clear where that's going to land, you know, more or less, you know, some details remaining to be hashed out.

But on the PV side, you know, we have the makings of a proposal. When we open the rulemaking there are going to be, you know, quite a number of stakeholders involved in that. And so where do those requirements for PV

specifically fall? I just ask that you sort of keep a pulse on that process with the Efficiency Division staff to make sure that you're, you know, in the right ballpark as you go forward.

So thanks.

MR. KAVALEC: And a key role will, of course, what you assume about compliance. And I think that's going to require some more discussion, both with the stakeholders and with the Efficiency Division, because that's going to make the big difference, is whether you assume 90 percent compliance or 50 percent compliance.

COMMISSIONER MCALLISTER: Well, I think we can assume a very high level of compliance on the new construction side.

But really, I think the question is: What is compliance? What is compliance going to mean in practice? Because not everybody is going to be able to install a PV. And so part of the conversation going forward is, you know, what do we do with shaded lots? What do we do with situations where it's problematic, you know, high-rise buildings and whatever?

And so I think what compliance means to how many buildings in terms of the actual

kilowatts of PV that go in, that's really the question. I mean, we see high compliance with the Building Code on the new construction side, so I'm less concerned about just the builders doing what they're supposed to do. But we're going to end up with a set of rules for the Building Code that are going to allow people options. And we need to make some assumptions about what options we think they're going to take. So that's, I think, where the uncertainty mostly lies on that.

MR. KAVALEC: Turning to electric vehicles again, as I said, this will be a difference maker in terms of our forecast versus other forecasts and where we end up at the end of the day.

So I propose, given the difference in methodologies and results so far that we've seen for our EV forecasts, that we dedicate a demand analysis working group meeting to electric vehicles methodologies and discussions of scenarios that we should develop for the Revised Forecast.

Also, to involve the Joint Agency Steering Committee, including CARB, of course, in

establishing final electric vehicle scenarios. I've talked to them. They've agreed to get involved in this. And this is similar to what JASC did a few years ago when they directed the AAEE scenario effort.

So we also want to refine and improve usage assumptions for electric vehicles. It's one thing to predict the number of car and trucks on the road, but how much they're going to be driven relative to a gasoline vehicle is important and critical in determining electric consumption. So we're using pretty crude estimates that we want to refine.

We're also working on developing EV charging profiles so that we can incorporate an 8760 set of loads for electric vehicles into our hourly load forecasting model.

COMMISSIONER SCOTT: So I wanted to underscore the importance of the DAWG meeting that will be coming up. Chris and Siva are working to pull contact information together for me, so that we can make sure we have the transportation electrification experts from the IOUs to be sure to participate in the discussion that we'll have about the EV forecast models and

the scenario development.

We also talked with the JASC about whether or not we might want the PUC to be involved, as well, so we can get additional information on the parts that they are working on, on the transportation electrification side, and that's really important as well.

It's also important to note that we're focused right now on light-duty electric vehicles. But as you know, we're also talking about medium-duty and heavy-duty electrification. So what we come up with probably be short of the amount of electrification that is a potential there, and that's something that we are working on.

And we're also looking into figuring out how we can -- and maybe the way to do this is kind of a scenario similar to the one that you proposed, Commissioner McAllister, for the doubling down on energy efficiency, you know, what do the scenarios look like that reflect the more aggressive electric vehicle adoption forecast that was needed from folks like Bloomberg, for example, or ICCT? And how can we

incorporate that in or use it for a comparison? Because ours is very conservative compared to some of those other numbers, just to give us, again, kind of a sense of the range and what does it look like.

So those are some additional things that we're doing in this space to give this some additional robustness.

But IOUs and folks, stay tuned for the email from me inviting you to participate.

CHAIR WEISENMILLER: I've been holding off generally, but just on the particular question, I think all three of us, I could probably safely say, and I suspect at least two other Commissioners, who will be troubled by a decrease in the ZEV loads. So certainly, this is one we're trying to pull in more perspectives. And, you know, basically, we both know, on PV and ZEV both, we're sort of at the -- what we think is the low part of the tail on the exponential growth. And so trying to sort it out is important.

But looking at all the things that are going on, particularly on a global basis for ZEV markets, it's just troubling. So, you know,

we're trying to make sure that we do a reality check on it.

COMMISSIONER MCALLISTER: I guess maybe this is more of a conversation among the Commissioners. But I guess, you know, it seems like really what's going on, really what tends to go on, you know, having been through several forecasts now and, you know, managed a couple of IEPRs, I feel like there's, you know, that sort of healthy skepticism. It's part of an inherent in any forecasts, you know?

I mean, I think, you know, you want to sort of try to -- you're trying to -- you have to rank your information sources and, you know, use the ones you think are best, you know, more centrally, you know? And the others ones you kind of sort of say, okay, well, maybe.

But it sort of helps you -- the less certain ones kind of help you bound your -- but I think, you know, if there's sort of a trend here, it seems to me that we that are more involved in the, you know, policy implementation, and then also the conversations with the policymakers about where they want to go, going forward, you know, we kind of want -- we see a lot of

potential in this modeling to help inform us about what we ought to be pushing for to get to the goals; right? And so that's not exactly what the forecast is sort of set up to do; right? It's set up to sort of tell -- you know, sort of crystal ball the future and, you know, based on the best information we have.

And so I think there's a kind of need. There's a thirst, you know, certainly for me, on efficiency, and I think for Commissioner Scott on the transportation, and those of us in our -- the areas that we most oversee to kind of have a back and forth about, you know, what if? You know, what would it take? You know, what levers would have to be bigger and different, you know, in order to get to goal X? And so -- you know, and how do we best take into account those possibilities out there on the marketplace? You know, if Bloomberg is right, then it would be great to be able to look back a few years from now and say, oh, that forecast, you know, at least had a scenario that reflected that possibility because, you know, at the time we kind of figured that might happen, you know?

And so I guess I'm just, you know,

wondering maybe if there's -- if the amount of interaction between the forecasting team and the individual offices are --

CHAIR WEISENMILLER: Well, I think that --

COMMISSIONER MCALLISTER: -- you know, talking about some of these scenarios?

CHAIR WEISENMILLER: I think that using the JASC with the ARB is a good next step. But I'm also signaling that I'm highly -- I'm not going to adopt a forecast that has ZEV dropping.

COMMISSIONER MCALLISTER: Uh-huh.

CHAIR WEISENMILLER: And I don't imagine there's any votes for that on the full Commission. That's just part of the reality check of what we're seeing. You know, I've been in China, god bless.

COMMISSIONER MCALLISTER: Uh-huh.

CHAIR WEISENMILLER: You know, I know what the Chinese are doing on the electric ZEVs. I've been in Germany. I know what they're doing. Obviously, you guys weren't there, but I'm trying to tell you, get the message.

COMMISSIONER MCALLISTER: Well, and several countries have said they're going to --

you know, by 2040, they're not going to have any, you know, fossil-powered cars.

So, you know, and I think another example is the demand response. Like demand response has been, you know, I think inadequate and underperforming for years. But, you know, next week we're having a workshop, sort of take the top off of it and, you know, open up the engine and see how we can, you know, tune it up to perform better; right?

So, you know, there's sort of reality projected for -- you know, past is prologue, right, there's sort of that perspective. But there's also like really aspirational goals that we need to find a way to express in a way that helps people understand what that would like in the future. And, you know, the forecast is one of the main things we have that does look forward. And so I think there's a need, you know, in that case, on efficiency and demand response to have -- you know, basically, to help use this process for better insight about what we should do, what we should do, what we ought to do, like a nominative question, you know, going forward.

So anyway, just a thought for us to ponder. Thanks.

MR. KAVALEC: Well, I'll agree with the Chair, that things these days are looking pretty rosy for electric vehicles. But it's still important to do, you know, what ifs on a pessimistic side, although, you know, whether that becomes part of the planning forecast or not, that's a decision to be made. But, you know, let's not forget the unexpected flatness we saw in PV adoptions in the last year. So we're able to still -- I guess my point is, we're still early in the market and it's still unpredictable. So we need to do scenarios both ways, higher and lower, I think.

Okay, finally, our hourly load forecasting model that we're in the processing of developing, this first round, we will have a version of the model to project hourly consumption loads for the three IOU TAC areas. And incorporated in this hourly load forecasting model will be, if all goes well, hourly impacts of additional achievable energy efficiency, electric vehicles, PV and residential time-of-use pricing, to give us a net consumption after all

these impacts have been incorporated in a final forecast for 8760 loads. And, of course, we want to catch up with the IOUs in incorporating an analysis of peak shift in our Revised Forecast.

So I guess that was all I had for now.

Additional comments/questions from the Commissioners?

CHAIR WEISENMILLER: No. Again, thanks a lot for this. It's a good presentation and it certainly hit issues.

I wanted to -- so I've got a number of questions, I just need to get it straight. Basically, we were trying to hold things until, you know, you got through.

But anyway, so more or less working back through things, I thought your conversation on the gap was pretty interesting. You know, it's sort of -- if you recall, I think 2008 was the first time in SMUD's history, maybe '08 or '09, but I think it was '08, that they actually had a decline, a decrease, a decline in sales from year to year. And, you know, it certainly got their attention. But as you said, that was sort of the economic driver.

So now the question is how much are --

these are policy drivers. It seemed like, you know, how much of that -- you know, you've got the list of, you know, what could -- you know, for Andrew's benefit, on slide six, what could have been the factors. But the one thing we can at least try to tease out of this, and I can probably get into that a little bit more later, is just we know the PV installation numbers year by year. And so it's possible to tease out to some degree, you know, what we would anticipate from the increased PVs on that gap.

Obviously, I suspect there's going to be other things left over, Andrew, that it's not like the -- you know, but it will be good, at least that part of it. The other pieces are hard to figure out. But that should be, you know, a reality check just on, are we talking 50 percent, are we talking 80 percent PV versus some of the energy efficiency parts?

MR. KAVALEC: Yeah. And I -- so, if I have some time, I'd like to sit down and try to tease out the individual proportions of these impacts that are contributing to this gap.

As you said, the PV part is simplest.

CHAIR WEISENMILLER: right.

MR. KAVALEC: You just look at the increase in PV. And that's responsible for about a third of the gap.

CHAIR WEISENMILLER: Okay.

MR. KAVALEC: So we know that.

CHAIR WEISENMILLER: Yeah. Because, I mean, the associated part, which again, thinking more globally, you know, when you're in China, say, they just -- this is pretty impressive that we're starting to bend the curve now at a time when the California economy is pretty vibrant, you know? And that decoupling of economic growth and sort of energy consumption certainly is a very huge message in places like China or India where they need to really grow their economies and, you know, the more sustainable part.

So again looking at -- you know, obviously, we'd all love to get into the weeds here, too. But, I mean, from a big picture, that's sort of a huge factor that I think people need to understand a little bit about how -- or, again, keep reemphasizing what the message is.

I noticed there's nothing on CCAs here, which I'm assuming means that at least the PUC has not asked us to untangle any of that?

MR. KAVALEC: Yeah. I'm leaving that for the Revised Forecast.

CHAIR WEISENMILLER: Yeah. Okay. That's good. I was just trying to understand that part.

And, you know, we talked. As you said, I think the two things that are coming out, you know, there will be a lot of miscellaneous stuff, but, you know, trying to get the ZEV forecast right, trying to get the PV forecast right.

And, you know, on PV, as you said, there's been some turnover, although there was a lot of -- you know, when people thought the tax credits were going to expire, and looking at NEM stuff, a lot of stuff accelerated in that, you know, so that just in the year-to-year stuff you could easily -- you know, the bottom line is, again, trying to forecast this part of the tail is hard. But there was a pretty good industry trend to pull some of the sales forward, you know, when the people thought the tax credit was going to expire or try to beat the NEM stuff. And then that should have -- you would expect that to lead to some flattening after that.

Now again, longer term, you know, presumably as we get -- hopefully we're getting

monthly data, or at least as we get more and more data through the year, we might get a better sense.

But ultimately, it would be important to stay connected to the Title 24 Standard work which is, you know, certainly going through its own bumps and, you know, variations on this particularly topic. And we're not there yet on where that's going to come out.

Yeah, I also thought, just following a point in Janea's comment, that, obviously, we have enough of a headache on the light-duty vehicles. But there's certainly more stuff on the heavy-duty, although that might be more gas forecast thing, you know? But again, that's something that in a JASC context, at least when you get there, I guess try to keep the ARB in the room for the conversation about heavy-duty --

MR. KAVALEC: Right.

CHAIR WEISENMILLER: -- and that part of it, so we don't get this piece nailed down and suddenly discover near the end that the big issue is what about heavy-duty, particularly the gas side of it?

MR. KAVALEC: Yeah. Aniss can address

this more fully, but we do do a heavy -- medium-duty and heavy-duty vehicle forecast. It includes electric vehicles.

CHAIR WEISENMILLER: Right. Okay. I think those are the ones I had coming out of this. But again, thanks.

And I think one that is really significant is your work on the sort of hourly model.

MR. KAVALEC: Yeah.

CHAIR WEISENMILLER: You know, again, I sort want to thank you for pushing that. Obviously, as you said, I think the energy efficiency numbers will continue to be issues, particularly how we deal with the doubling, much less how to deal with, you know, what we would like to see in terms of federal appliance standards.

COMMISSIONER MCALLISTER: Yeah. Yeah. I mean, there are all sorts of issues and things.

CHAIR WEISENMILLER: I'll kinds of issues. But I think big picture, if we can really focus on the ZEV and PV, that will do us well.

MR. KAVALEC: Okay.

COMMISSIONER MCALLISTER: So I just want to mention, you know, increasingly, we're having to integrate these conversations. So, you know, we've got three divisions here, you know, that really need to channel to Chris and the Forecasting Team what -- all they know about what's happening in this space. And certainly the doubling is a big deal in a lot of pieces, a lot of gears.

And I wanted to just underscore, you know, my hopes for some of the analytical tools that we're developing. You know, at the moment it's mostly with the Efficiency Division and the Energy Analysis Division. But the idea that we're going to have a data lake that's got a lot more disaggregated longitudinal information in it, and a mandate from SB 350 to sort of untangle what's going on with efficiency, in particular, is going to -- you know, my hope for all that is that a couple years from now we look back and we're going to be able to do some of this disaggregation that we're so -- you know, that we're sort of watering at the mouth for. And, you know, if we build the tools right and we have it properly staffed and sort of, you know,

automated enough that it's not too labor intensive, then I think we'll be able to, actually, retrospectively have a lot more knowledge about what happened, which make will make life easier for you as we want to, you know, project forward.

So, you know, the resources we're putting into that, I think are going to help everybody.

MR. KAVALEC: Yeah. I didn't bring up the topic of geographic disaggregation, but that's still something in the mix. And it's really going to depend on what we end up getting in terms of regular data through the current rulemaking, what we can support. So once we -- that -- those decisions have been made, then we can sit down and say here's what we have and here's what we're planning to do in the future in terms of special studies and more geographic disaggregation.

CHAIR WEISENMILLER: Yeah. I forgot to ask you, I mean, there's always been this perennial issue of where are we on the AAEE studies, you know, in terms of timing and making sure we get those, in a timely fashion, to feed into the forecast. How are we doing this year on

that?

COMMISSIONER MCALLISTER: The Navigant stuff?

CHAIR WEISENMILLER: Yeah, the Navigant stuff, both in terms of, obviously, there's the potential, there's, you know --

MR. KAVALEC: Yeah. Well --

CHAIR WEISENMILLER: -- the holes. I mean, that whole thing is pretty foundational --

MR. KAVALEC: Uh-huh.

CHAIR WEISENMILLER: -- to what we're trying to do. And, you know, obviously, things always take somewhat longer than we hope.

MR. KAVALEC: They always do, but I think if things go well we're on track. In the latter part of August, we're going to begin the analysis and develop the scenarios.

CHAIR WEISENMILLER: Okay.

MR. KAVALEC: But all the tools are there. The potential study has been done. It's just a matter of evaluating the scenarios that have been done so far for the potential study, think about additional new scenarios that may be involved, and put those together and develop a, you know, set of candidate scenarios for the

managed forecast.

The thing that, as I mentioned, before, we have -- we also want an 8760 set of loads for AAEE to be developed. That will take a little longer, but hopefully that will be -- both of those things will be ready to go by the time the Revised Forecast is put together.

CHAIR WEISENMILLER: Okay.

COMMISSIONER MCALLISTER: So on that front, so are you having any issues or barriers related to sort of the differences between the work that Navigant did for the IOUs versus the POUs? Are you able to kind of navigate that? Because I understand there are a few differences between those two efforts.

MR. KAVALEC: Yeah. I haven't been involved enough yet on the POU side to --

COMMISSIONER MCALLISTER: Okay.

MR. KAVALEC: -- give you a good answer.

COMMISSIONER MCALLISTER: Okay. Thanks.

MR. KAVALEC: Okay. So speaking of electric vehicles, we will now turn to that topic with Aniss Bahreinian, our EV expert.

MS. BAHREINIAN: Good morning, Commissioners, stakeholders. Thank you for being

here.

Yeah, Chris is taller than I am, so I have to bring it down.

Today we are going to talk about PEV forecast, but we're going to talk about the forecasting approach, not the numbers themselves. The different numbers, as has mentioned repeatedly, that there are differences between different forecasts. And we're trying to forecast on explaining our forecast, but in the middle, I'm going to sprinkle some comparisons with some of the most mentioned forecasts out there, which is Bloomberg and others, so I'll be talking about all of those.

So again, it is about methodology elements. And we are going to first talk about utilities, and then talk about our own forecasting approach.

There are a number of scenarios of the future out there regarding the PEVs. And these scenarios, some of them are forecasts and some are not forecasts. Some can be best characterized as pathways that start with a goal at the end, at some point in the future, and then work their way backward.

What we do here is, obviously, the forecast, but there are also different kinds of forecasts. There are -- if you look at different forecasts, you have -- some of them are supply forecasts, they are heavily focused on supply, such as Bloomberg, and some of them are heavily focused on demand, which is entirely what we do here. And then there are some forecasts that have elements of both, both the supply and the demand. Ideally, ideally, and in the long term, perhaps, we can have a supply, a vehicle supply model, in our own division, so that we can iterate back and forth between the supply and demand, but we are not there yet. That's something for the future, we can certainly address, but certainly not for this IEPR.

So the utilities have to have some idea about what the future holds for them, because they have to make infrastructure investments. Infrastructure investments do not happen overnight. They have to spend a lot of time and they have to see some point in the future in order to be able to make those infrastructure investments.

If they overshoot, if in those estimates

or forecasts, if they overshoot, then they could face the question of stranded resources. If they undershoot, then they are going to have the question -- the problem of reliability. So they have to be -- they have to walk in a balance so that they could address both sides.

Now the PEV projections, the PEV scenarios that I have seen from different utilities, essentially they are either, I mean, to different degrees, depending on whose forecast we are talking about. They rely on achieving the existing state policies' goals. Of course, that the laws that are in place are laws, and they should be followed. And it is safe to assume that the laws would be complied with.

They also rely on a 2014 study that was done for California Electric Transportation Coalition by ICF, and it was sponsored by different utilities. So we will see different elements of that, actually, in some of the utilities forecasts. We, ourselves, have actually used some of the TEA analysis in our Off-Road Transportation Electrification Forecast. However, when it comes to light-duty vehicle and PEVs, we are using the internal CEC models, but

not everybody has those models. Therefore, there has been a reliance on the TEA study.

This year, Southern California Edison is relying on Navigant's forecast of technology market shares. And they also -- some of the utilities have also used our 2016 Energy Commission IEPR updates for the EVs.

Now if you look at the TEA study, for short, Transportation Electrification Assessment, it was based on the ZEV that was originally developed in 2012, so they used those numbers. The ZEV 2012 has the compliance levels. If you look at only the vehicles and not the ZEV credits, it was based on approximately one-and-a-half million.

Now our TEA study had three different scenarios. One is -- and the names that I have put there are exactly the names that were used in the TEA study -- one is in line with current adoption or what I call low, another one is in between which is the mid in the middle of the two, low and high, and then one is what they called aggressive adoption. In the aggressive adoption, they took the ZEV 2012 numbers, the one-and-a-half, let's say, roughly, million

vehicles multiplied by three. So they just took the ZEV mandate numbers that were coming out of that, multiplied it by three, and they called it aggressive adoption.

Notice, also, that, in line with current adoption, which is the low, what is interesting to know is that the low is based on a 50-50 distribution between hydrogen vehicles and PEVs. So the assumption is if 50 percent of the ZEV mandate is not by hydrogen vehicles, then the other 50 percent would be. So they are taking off -- hydrogen is already taking off 50 percent of that, therefore you're going to have a low PEV forecast.

Now about Energy Commission? These are the scenarios that we are defining. We refer to them among ourselves as common scenarios. And the reason why we call them common scenarios is that the data that we are using, the population income and price data that we are using is the same as is used by the rest of the Demand Analysis Office.

Notice the first two. These are the key inputs, of course. These are not all of the inputs that you use. And some people were

saying, well, how can we duplicate your forecast? Well, we have over 150 different variables. We had a ton of data. For some things it is impossible to just replicate it correctly, accurately. But these three variables are important variables in our model and in our forecast. Population and income, essentially, drive the population of the vehicles. So when we are forecasting total population of all EVs, population and income as two variables are the ones that are playing the prominent role.

Look at the fuel prices, however, you can see that fuel prices, we are mixing -- we are moving the petroleum fuels and electricity and natural gas in opposite directions. And the reason why we do that is, again, we are generating a demand forecast that should be consistent with the rest of transportation and electricity. So we want to generate one that -- we want to generate a forecast that will develop the highest and the lowest in our forecast of the EVs, because are exchanging that data with the rest of the division and they are incorporating it into their forecast.

So there, in the high demand, which can

do better as the high electricity demand, petroleum fuel prices are high, electricity, natural gas and hydrogen prices are low. So in this case, electricity, natural gas and hydrogen prices, when they are low, you could better call it high alternative fuel vehicle.

In the mid case, of course, it is in between.

And the low demand case, notice again, petroleum fuels and electricity, they are moving in the opposite direction, because we want to substitute EVs for petroleum -- for ICE vehicles, for gasoline vehicles.

Now the CEC's light-duty vehicle forecast, is based on economic and demographic. Again, as was evident in the previous slide, economics and demographics have a lot to say about the PEVs, about the MDVs, and they determine. So if our economic and demographic forecast are a straight line going up, that means that our MDVs are going to be a straight line going up. So if they're going at a curve, because it is entirely determined by these factors, they are going to take the shape of the inputs, actually.

COMMISSIONER MCALLISTER: Aniss, can I ask a clarifying question --

MS. BAHREINIAN: Sure.

COMMISSIONER MCALLISTER: -- on a previous slide?

MS. BAHREINIAN: Sure.

COMMISSIONER MCALLISTER: So when you have -- when you say the fuel prices are high and low for, you know, petroleum fuels and electricity and natural gas, hydrogen, is that high and low relative to one another or high and low just relative to some scenario of pricing?

MS. BAHREINIAN: It is --

COMMISSIONER MCALLISTER: Because, I mean, you can argue that for EVs, you know, a high electricity price and even a relatively modest fossil fuel price, it's still going to be cheaper to operate and EV, even in that scenario.

MS. BAHREINIAN: Yes.

COMMISSIONER MCALLISTER: So I guess I'm kind of just wondering what the -- how that's all structured?

MS. BAHREINIAN: Yes. We are just trying to get the maximum. But the high and the low is relative to the price scenarios for petroleum

fuel products versus electricity and natural gas and hydrogen. We have three scenarios for each of those fuels. So what we do, is we mix and match the high scenario of the petroleum fuels with the low scenario of the electric prices.

COMMISSIONER MCALLISTER: Within the range of possible electricity prices --

MS. BAHREINIAN: Yes.

COMMISSIONER MCALLISTER: -- and gasoline prices, respectively?

MS. BAHREINIAN: Yes.

COMMISSIONER MCALLISTER: Okay.

MS. BAHREINIAN: Absolutely.

COMMISSIONER MCALLISTER: Thanks.

MS. BAHREINIAN: So the CEC Light-Duty Vehicle Forecast of 2017, the 2017 forecast is based on our residential and commercial survey of consumer preferences that was conducted by Resources Systems Group, or RSG, on our behalf. So we really have the latest data that anybody wants. I mean, it completed in February 2017. You can't get any more recent than that. And then we used this -- the survey data is used to update the models. So we do have a set of models that we are using, but we keep updating it with

the new data because consumer preferences keep changing, and as such we have to also develop new models that are based on the new consumer preferences.

Later -- and then also the last projections of vehicle attributes, accounting for announced and projected technology developments in 2017 and beyond. So we search and look and try to see, what are the latest projections of vehicle attributes?

The CEC model is based on discrete choices analysis that was originally developed by Daniel McFadden at UC Berkeley. It is devised from economic theories. It is based on economic theory, it has a good foundation. And McFadden used it to predict BART ride issue, before it was even built. And the model has many applications in transportation, energy and marketing.

Now the important part that you see here is what is it that determined technology fuel type choices? Now what determines all of those economic and demographic factors, we forecast the population of the light-duty vehicles and what is being sold on the market. When it comes to the trends between different vehicles and fuel types,

then these are the factors that are going to enter into consideration of the consumers.

Number one is the consumer preferences for different technology and fuel type. And what it does, it allows the model -- allows the consumers in the model to substitute between different fuel types. If there is an increase in preferences for EVs, then the consumers are going to substitute EVs with gasoline vehicles, for instance.

We also have preferences for vehicle class. So these are two separate sets of preferences. We check counts for substitution between classes of vehicles. Now these are the kind of substitutions that are related specifically to fuel type and class. But as you can see later, consumers also substitute for other reasons.

Now this is the set of classes that we have. Note here, we have 15 different classes of vehicles versus, for instance, in the Bloomberg really had only small, large mid-size and SUV. We have to be more precise because we are forecasting fuel demand.

Note here the light blue cells are the

sales that ensure all of the different classes, gasoline, for instance, has different makes and models in every single class of vehicle. So if you want a van, if you want a large van, no problem, you go to the store and you buy one that is in gasoline.

The green cells are showing all of the different technologies that are going to be introduced into the market at some point in the future. This is our best guess in it so far. And we can actually use more input on this from others if they have more information about the classes that will enter the market.

And the white cells are the ones that will never be introduced in this model. We're not saying that they will never be introduced, but in the model, those are absent. You can notice here that between PEV, EV and FCV, you have the most white cells in these columns.

Salmon colored cells are actually the ones that are being deleted. Naturally, a lot of diesel is getting out of the market, so you could see most of the diesel makes and models are being deleted, as well as one of the makes of fuel cell -- I'm sorry, flex-fuel vehicles.

So the class is important. This is another common thing between what we do and what Bloomberg actually said. Bloomberg also believed that class is important. It is very important to introduce EVs/PEVs into the larger vehicle classes, because consumers are moving in that direction. Our survey shows that, Bloomberg was emphasizing, so this is catching up, that manufacturers have to build cars in the larger vehicle classes, and that is important to the consumers.

Another set of factors that we do incorporate that do impact fuel type choice are government incentives, state rebate, Federal Tax Credit, HOV lane access, all of these are important to the consumers, and these are important. Our model actually accounts for these separately. That's important because a dollar of tax credit acts differently for the consumers than a dollar of state rebate compared to a dollar of price reduction. It is important to include them separately. Most other models or forecasts, they don't consider them separately. They just up and down the price of the vehicle. And we see that, actually, they have different

impact.

In one of the -- so these are also our policy variables. We are talking about policy analysis. These are the variables that we are using for policy analysis. So one exercise that we did was, okay, what does it take to get to the 4.2 million?

And what we did was by changing these incentives over time and in a way that doesn't increase -- that is what is called revenue neutral, how can we increase taxes on gasoline vehicles, for instance, or fees on gasoline vehicles and rebates on PEVs or FCVs, so that we could reach the 4.2 million? So we can exercise these. It's possible because we have these policy variables.

What are the other determinants of technology fuel type? Well, very important, it's the vehicle price. Vehicle price is very important in choice of the consumers. If the manufacturers can manage to bring the prices down, consumers are going to buy EVs. Because in our survey it shows that consumers actually have higher preferences for EVs, for PEVs. That has been shown in the most recent survey that we

have, which is why we are forecasting more EVs than PHEVs.

This is, again, very entirely consistent with what Bloomberg is doing. Actually, I think that perhaps Bloomberg is the only forecaster that is forecasting like we do, that EVs are going to grow in the market. Even though they are looking at it from the supply side, we are looking at it from the demand side, we are both reaching the same conclusion: EVs are going to overcome the other ZEVs.

Fuel economy, of course, is very important. If you are underestimating fuel economy of BEVs or overestimating them, it's going to have impact on consumption of electricity, so that is an important factor.

Cost per mile is very important, fuel cost per mile. So if the electricity prices and gasoline prices, when we are looking at them in terms of how much it costs to drive one mile, that is what we are considering in our forecast. We do not look at the price of gasoline and price of electricity, versus how much it is going to cost to drive one mile. This is going to be impacted not only by the price of the fuel

itself, but also by the fuel efficiency of the vehicle.

Maintenance cost is another factor.

Range; this time around we have noticed it has gained significance. I think that perhaps one reason why it has increased significance this time is because consumers are now more educated about the EVs. So increasing the range of vehicle is going to have impact.

Acceleration is actually important. And NREL has found that acceleration has great impact on choice. We have found the same thing in our survey and in our forecast.

Number of makes and models is important, not as important as some of the other factors, but still, it is an important factor.

And then refueling time, refueling time is very important. And I have to tell you that when I was watching a documentary on Bloomberg, they were showing all these screens with the stream of data that is coming every second from different places from every part of the world. I was really intimidated. I was saying, well, how can we ever compete with that? We don't have all of this. Even now as I'm talking to you about

Bloomberg, what I'm saying is not based on reading the actual report, because we don't have access to it. I have only read the executive summary, and I have participated in the webinar that they had yesterday.

But even so, with all of the data that they have, which is, as I said, very intimidating to us, with all of that data, they still didn't even mention Toyota's new technology on batteries that is going to actually reduce the refueling time. Even they didn't have that in their study, with all of the data that they have at their access.

So this is an evolving market, it's in flux. And still, things are not settled yet. There's a lot of uncertainty.

In addition to all of those factors, we also account for infrastructure. And the infrastructure enters our model in terms of time to fuel station.

Now of all these, as we have been mentioning, actually, since 2013, vehicle price is the more important factor. What can we do when Bloomberg puts out that forecast, which is mostly a supply-based forecast? But Bloomberg is

saying that battery prices are going to come down to $73.00. When battery prices come down, then what will happen? Price of the vehicles are going to come down. So then maybe we can incorporate Bloomberg information into our forecast as to the vehicle prices and the range. So what we can do is to look at what they have generated and incorporate that into our scenarios. And perhaps we can develop another alternative scenario after discussion at DAWG and with the CPUC and everybody, so that we can increase the number of PEVs in our forecast.

If I have time, I would talk more, but I think I'm done. Our OM is telling me I'm done.

CHAIR WEISENMILLER: Great. Thanks. I just want to reiterate, we're not adopting a forecast. I'm not voting for a forecast that has ZEV going down. Everything that's occurring now in the market is in a positive direction.

As you indicated, every day you see more stuff. For example, the Financial Times, this morning, talked about the economic can put an impact on the general manufacturers for the high luxury vehicle, saying they're really threatened now, that comparing the number of parts in, you

know, the latest Tesla, there's 7,000; there's 30,000 in their cars. And so that has -- gives them a fundamental competitive disadvantage which they now have to overcome.

Now again, I realize I'm not trying to say, okay, let's go through every press release today that would lead you to think -- you know, because the Volkswagen settlement, is that in here. You know, the thing is, is that -- I mean, you know, it's just -- come on. I mean, if you look at the waves coming, there's a lot of uncertainty on timing of this stuff. It's pretty clear where it's moving. Diesels are gone. You know, basically battery costs are coming down.

Again, we keep talking about the battery giga factory here. China has tons of giga factories. You know, they have like 11 compared to 1. You know, they have very, very aggressive goals. I mean, why is Toyota moving into ZEVs after going Toyota Prius oriented or hydrogen oriented? It's because they're able to sell cars in China. You know, obviously, it's a lot easier in China when you say, okay, you're in Beijing, you want a car tomorrow. You want a BEV tomorrow? Or you can get in a lottery and maybe

sometime in the next few years, you might get an IC engine. Obviously, everyone doesn't have that power. But, you know, that really forces the OEMs to start, you know, getting pretty aggressive on this, you know?

So again, getting back to the consumer preference, I appreciate that. But I'm just telling you, in terms of everything we see, it's not just Bloomberg. You know, by looking across the board, everything is saying, my god, we went down, you know, and thinking, trying to figure out that you could easily say, well, we went down because X happened, because, you know, this happened or that happened.

So, you know, anyway, it's just we're in a very tough time. I think certainly going forward, you know, using the working group, bringing ARB in, but certainly, you know, listening to what the utilities are saying, getting the best information at this time. But I think as we do that, you know, it's going to force us to rethink these.

MS. BAHREINIAN: And thank you very much. And we appreciate -- I appreciate all the input and feedback and guidance that we get.

I should also -- one of reasons why we are coming down, compared to the previous forecast, I want to just explain that. Because in the Revised Forecast in 2015, we made a number of changes. One was that we increased conservation preferences over time. So we developed to scenarios that made it in the high scenarios that were based on increased preferences.

What we have done in this Preliminary Forecast that we have released, we kept consumer preferences constant, which is not realistic because we know consumers are going to have improved preferences. And we can work with DAWG and others in order to develop a better way, a good way to increase consumer preferences, as opposed to one that is arbitrary.

The other thing that we did was, if you recall from 2015, these are David Green's, really inspired by David Green and the Academy's study on --

CHAIR WEISENMILLER: Right.

MS. BAHREINIAN: -- transition to alternative fuel vehicles. And what we did, they said in their study, which wasn't a forecast, but

what they were saying was that in order to meet the goals, we're going to have to see vehicle prices coming down to parity with ICE vehicle prices in 2050. So in the mid scenario, in the 2015 IEPR, we made the assumption, we artificially lowered the prices of vehicles to the same level, to parity with gasoline vehicles in 2050. In the high case, we made it more aggressive and we lowered the prices, brought them to parity in 2030.

CHAIR WEISENMILLER: But I'm telling you, the Financial Times said today --

MS. BAHREINIAN: Yeah.

CHAIR WEISENMILLER: -- looking at the number of components, prices will be lower, okay? And I should also note from your preference, when the state talks ZEV, we're sort of indifferent on whether it's hydrogen or battery, it's ZEV. So, I mean, I guess that's something we haven't got to and how do we deal with that split, a question?

But, you know, certainly in terms of -- so it's not, gee, hydrogen is occurring, so we're not going to hit ZEV, it's cumulative.

MS. BAHREINIAN: Yes. And I should --

one of the things the class table letter showed you, this one, you see that you have FCV here. And there are only three classes that are populated by FCV.

CHAIR WEISENMILLER: Uh-huh.

MS. BAHREINIAN: One of the things that we are doing, one of the things that we have looked at, is another kind of an FCV called plug-in hybrid FCV --

CHAIR WEISENMILLER: Uh-huh.

MS. BAHREINIAN: -- which is used now in Europe, but we don't have it in the U.S. market.

Bloomberg is right in looking at global market. Because when it comes to supply, it is really global market that impacts it. It is a global market because manufacturers are producing for the global market. They don't produce for California --

CHAIR WEISENMILLER: No. GM sells --

MS. BAHREINIAN: -- or the U.S.

CHAIR WEISENMILLER: -- more cars in China than it does --

MS. BAHREINIAN: Absolutely.

CHAIR WEISENMILLER: -- in the U.S.

MS. BAHREINIAN: And Tesla also sells in

China.

So if there are some vehicles or technologies that are available in the global market, say in Europe, plug-in hybrid FCV, chances are that those are going to migrate at some point to the U.S. economy.

So what we are thinking, also, about doing, in addition to increasing the number of classes that are in this table, we're also going to add another one that is called plugin hybrid FCV. And we did a test with the model, and we noticed that the consumers really liked that. If we add this plugin hybrid FCV, the sales went up of the ZEV vehicles.

So there are a number of options that we are going to have to discuss and consider when we are in conversation with DAWG or the CPUC and ARB on increasing the number, making it more realistic, increasing the high scenario, the mid scenario versus the low scenario. We could increase the high scenario and create another alternative scenario that addresses all of these different changes, even though there may be uncertainty about it.

CHAIR WEISENMILLER: Okay. Do you have

anything?

COMMISSIONER SCOTT: No. I mean, I think the challenge between the Preliminary Forecast and the Revised Forecast is there's a lot of work left to be done in between preliminary and revised. It's kind of potentially analogous to seeing the line without the AAEE in it. That completely changes what the picture looks like. The conversations that need to be had within the DAWG have not happened yet, and those will make, I'm assuming, those will make quite a difference in what this looks like between now and revised.

Additionally, the conversations that we have with ARB, talking about the scoping plan, the ZEV mandate, other things like that, I think also have the potential. And those conversations have not taken place yet, but they are important.

And I agree with you, our trend lines are extremely conservative and not reflective of what's sort of happening the real world around us. And that's something we need to figure out, kind of, as well between now and that Revised Forecast.

CHAIR WEISENMILLER: Yeah. Well, we need to get onto the other big topic, you know, the DG

part.

MS. BAHREINIAN: Yes.

CHAIR WEISENMILLER: But I'm certainly going to encourage you to work closely with Staff on this topic.

MS. BAHREINIAN: We will.

CHAIR WEISENMILLER: And look forward to Staff working well with you on it. Thanks.

MS. BAHREINIAN: thank you very much.

MS. RAITT: So next we have Scott Shepard from Navigant Consulting. He's going to be presenting via WebEx.

Go ahead, Scott. You can let me know when you want me to change your slides.

MR. SHEPARD: Okay. Can you confirm that you hear me?

MS. RAITT: Yes, we're ready. Thanks.

MR. SHEPARD: Oh, okay. Thanks. Well, thank you, everyone, for letting me present. Sorry I can't be there. I'm joining you from England. But I am a former California resident. And had I still lived there I would be there.

So anyways, my name is Scott Shepard. I am an Analyst with Navigant Research. And I manage the Electric Vehicle Research Service for

Navigant Research. And what I'm going to be presenting on here is the methodology that we use for the annual public, the Electric Vehicle Geographic Forecast Report, which takes our global forecast of national markets and disaggrates it among the North American markets, that is to say it is a forecast that produces sales forecasts and population forecasts for states and provinces in North America, and then sub-state populations within both those countries, so basically looking at core base statistical areas and census conglomerations in Canada and the United States, respectively.

With that, I think we can move on to the next slide. Thanks.

So just a real quick agenda here. I'm going to provide an overview, only about the technology competition model, while providing an overview, really, of some of the sensitivities within the model, some of the uncertainties about it. We have a slide in the back that provides a little more explanation about the actual calculations that are driving the model and where particular inputs are weaving their way into the actual calculations. And then the second part is

to discuss our disaggregation method.

So with that, we can move on to the next slide.

So while you have this in front of you, I'll just provide an overview of what's going on in the model at a high level.

So our forecast is driven by -- at the national level. We are doing this top-down approach to assessing the competitive relative value of each powertrain fuel combination within a market.

So we look at the light-duty vehicle market and we split it up into two classes. The class that involves all passenger car or body types, such as hatchbacks, sedans, coupes, what have you, and then the class of vehicles that includes -- that are larger, basically the light-truck classes is what it's commonly called, and that includes crossovers, SUVs and compact pickups

And then in those two classes we look at 12 different combinations of powertrains and fuels. And those powertrain and fuel combinations included, you know, the internal combustion engine powered by diesel or gas, the

hybrid powered by diesel or gas, by the battery-electric vehicles, fuel cell-electric vehicles, basically all of those possible combinations. We do a grind-up assessment on what the average costs of those vehicles are based off of their unique vehicle components, such as for batteries, the -- I'm sorry, for battery-electric vehicles, the battery, for fuel-cell vehicles, it is the fuel cell that's within the vehicle that is providing power to the battery.

So from that ground-up assessment of the vehicle costs, we then assess what the purchase cost of that vehicle are using information on government additions and subtractions, basically taxes and subsidies. And we then account for operating costs, basically doing what any fleet operator would do in terms of assessing which vehicle they're going to purchase for their state, which is to do that total cost of ownership analysis for each vehicle on a certain ownership period. So our period is roughly 36,000 miles or three years.

And once we have identified that overall cost structure for the vehicle, based off of these more, I guess, easily findable or

quantitative economics, we then factor in some of the more qualitative aspects of each technology, the primary component being infrastructure. And that component we view as, agnostically across all powertrain fuel combinations, a penalty that is added to a powertrain fuel combination if that powertrain cannot compete, its infrastructure cannot compete with the market-leading option. And we model that as a -- that penalty based off of the costs that would have to fall on somebody who is adopting the vehicle and would likely have to use an alternative vehicle for a certain percentage of trips through a period of ownership.

So that's a high-level overview of the model methodology and the major pull factors.

Within that method, we're able to test certain input parameters, such as oil prices, lithium-ion battery prices. A lot of the work that we do, besides just putting this report out, in terms of custom projects, we often test sensitivities to subsidies or government policy changes.

The report that we produce, I mean, I'm talking about here, we typically keep all

policies, major policies that are impacting the vehicle market, such as the Federal Tax Credit or corporate average fuel economy standards or the EV Program, as staying as their written throughout the forecast period we're looking at. But with some of the lower level market interventions from some national players, we typically have those particular incentives or subsidies or interventions building out along a timeline that aligns with the reduction in the battery price or the premium moves (phonetic) of the vehicle for battery-electric or plugin-hybrid vehicles. And the reason for that is these policies are typically highly uncertain in terms of their length or longevity.

So given that, you can see some of the major sensitivities when you look at regarding our input parameters. And as you see on the chart to the left, you have oil prices and battery pack prices. And those are the two major areas of uncertainty that are also fairly volatile. Definitely, oil prices are more volatile than lithium-ion battery prices.

And so this just gives you a sense of how

our model works in terms of the competitive components within it, in that if you are tweaking your oil price up, you are tweaking your oil price, you are diminishing the relative competitive value of the conventional or the stop-start vehicle against the plugin vehicles, battery-operated vehicles, battery-electrics and the plugin hybrids.

So you can see the benefit that is created when you toggle up oil prices one percent, or whatever, you have a net benefit of a just slightly over two percent impact on plugin vehicles in 2017. The sensitivities are not linear. There's a curve incorporated, and they change over time. For instance, if you were to look out, you know, to 2050, you'll eventually see that tweaking up oil prices does not help hybrids anymore, and eventually it starts to hurt them because it makes battery-electric and plugin hybrid vehicles so much more competitive.

You can see this dynamic in the chart below, oil prices, in that it's showing the impact of lithium-ion battery pack price declines, which initially provide a benefit to hybrids because they're also benefitting from a

slight decrease in battery pack prices. But that quickly dissipates as plugin vehicles become more competitive on behalf of the battery pack price decline.

So with that, we can move onto the next slide, where I discuss some of the other major uncertainty areas within the model. So this is really to provide a sense that, you know, we generally, within our reports, we're looking at a more major macro area-type parameters that are influencing the model. The ones that we don't typically look at for our (indiscernible) reports are these ones, in terms of flexing certain scenario parameters, but we've definitely done that before.

And this just gives you a sense of what particular parameters are affecting what components of the model conceptually, and in real life. So Federal Tax Credits, they impact the total cost of ownership for the vehicle. If you were to remove that, the sensitivity to that particular variable, it would be very high. I mean, you'd significantly impact the market in the near term. But the deviation from what we have built into our forecast is very low. It's

not -- we don't see that as likely to go away. But -- and that's just an example for all the rest to follow.

Some national stakeholder interventions are inclusive of everything from utility incentive programs to state subsidy in the same programs, local government incentive programs, the Electric Buy America Program. At the time this report was being developed, EBA hadn't been really produced yet or put together. So when the update to this report comes out, the impact of EBA will be integrated into the update.

Let's see here, so we can see some of the other components. There is one thing I should touch on here, is automaker support and vehicle availability timeline. That's an area of very high uncertainty. We get a lot of different feedback coming in about product development timelines and deployment dates and where vehicles are being deployed. So generally, we try and hit the mark with timelines, but that is highly proprietary data that doesn't usually come out exactly how we hope it would.

In terms -- and I guess this is an important area for me to point out now, and I'll

probably touch on it later again, but in terms of how that relative competitive valley that I was speaking to earlier is influencing model outputs is the relative competitive value aligns with the average figure for sales per model. So if you have a high relative competitive value, meaning you have a very competitive vehicle based off of its TCO, it's total customer ownership, then you're going to see higher than average vehicles sold per model put into the market.

And that's where the vehicle availability component becomes very important. Because if we have a very high relative competitive value for a particular technology but there's no technology in the market, then -- and we say that there is going to be, then our forecast can be off by a substantial amount. So it's an important area to point out here in terms of uncertainty.

And the last one I'll speak to here is the uncertainty of automated vehicle systems and how they might impact the overall transportation system. This report is really at the end of a series of models that are looking at how various transportation technologies are impacting the market, or will impact the market when they are

adopted. And so looking out past 2025, you know, and longer, into 2035 and 2050, we can assume that some form of automation is going to be impacting the transportation sector. And in that capacity, we need to develop a way in which we can understand how it's going to impact the market and either improve the conditions for certain types of powertrain and fuel combinations or not.

And we can go to the next slide.

So this is our forecast for the next ten years, well, next nine years, I guess, now, on the plugin electric vehicle market in North America. Our motto is it's demand driven and it's supply driven. There is that demand point where we're assessing the relative competitive value of each powertrain fuel combination. But there's also the supply component which is that of vehicle availability. And the vehicle availability component is being driven not just by the automaker announcements that we see coming to the market, but it's also being driven by fuel efficiency standards and the ZEV Program.

So we are doing assessment of where the market needs to be at, at 2025, in terms of

volume for automakers to be compliant, and within their range because there is a range by which automakers can be compliant in terms of strategy. It can be a certain amount of plugin vehicles and a certain amount of hybrids and whatnot. And from that point we have a number of models that we're predicting come into the market past the near-term projection that we have, which is usually three to four to five years, because for the (indiscernible), unless you know about automaker strategy.

So that helps us get an idea for where automakers will be in 2025, is looking at those particular supply-side drivers. And by that -- by 2025, we're predicting market share for planned vehicles at around seven percent of the United States market.

And, yeah, with that, I can move on to the next slide.

So Aniss was discussing earlier about the way this model is working in terms of conceptualization. This provides a little bit of an overview regarding our high-level approach to the market in terms of the total cost of ownership. Now that's seasons with the relative

competitive value.

This is our state disaggregation method. There was another disaggregation that we do for sub-state of sub-province populations. But at the state level, we're kind of operating on the same principle in that we are trying to determine the total cost of ownership at the state level.

So we've done it at the national level, and now we're doing it at the state level to try to desegregate what our national picture looks like when we chop it up into all its component parts. And that gives us an assessment of what the market share is likely to be in each state, based off of the particular sub-national interventions that are happening at the state levels, the unique aspects going on the market concerning vehicle preferences, the demographics of the market, infrastructure development within the market.

As you can see within this influence diagram, there is a feedback that is created between the state PEV population and the infrastructure. And that goes back into what I was talking about in regards to how we factor in infrastructure as an agnostic component for all

powertrain fuel combinations in that the -- all these fuel combinations basically get a penalty for not having a really competitive infrastructure field. But the infrastructure is also driven by the plugin -- by the alternative fuel population. And as you have an emerging population, you have a better business case for that infrastructure. And you create a loop over time where one influences the other.

And so what we're seeing in this model is that as plugin vehicles come to certain markets, then make the business case in those markets better over time, and therefore attract more and more sales. And that's just something I wanted to point out here is that's one of the components to our model that is one of the reasons we see California becoming a very strong plugin electric vehicle market in the future.

So something I would like to point out about California particularly, we have done a number of surveys on the national market. And in comparing the surveys that we get back, we have found, typically, that California responses show that consumers typically have low vehicle capability requirements. That means they are

more willing to purchase a vehicle at the lower vehicle range in terms of battery-electric vehicle, and they're less concerned about other vehicle capability requirements, like all-wheel drive, they're less concerned about battery reliability, whereas other portions -- whereas other regions in the United States are more concerned about those, significantly more concerned about those aspects of vehicle ownership than in California.

There are other attributes to the California population that also would precipitate that they would be interested in plugin electric vehicles rather than other options, besides the fact that they often say more than other pops that they are interested in plugin electric vehicles, which is a question we do ask on our survey.

But besides all these points, there's also the aspect that California has typically had aggressive stakeholder interventions. And these should be noted because they do contribute to that feedback, that positive feedback loop. And the component of the analysis that is also important to note is that the federal purchase

incentive phases out based off an OEM volume cap. And as you create more positive conditions for one state, that state is more likely to attract more of those federal purchase tax credits over the forecast period.

And that increases the benefits to the state at the expense of other states. Because we have a Supply Forecast, that state becomes, in terms of the feedback loop, fairly strong in terms of attracting sales into the future because, for one, it's diminished the infrastructure penalty factor than some other states that have a smaller population and that can't really sustain strong growth for that state in terms of getting rid of that penalty based off of the PEV population along.

So it's just one more thing to note in terms of what's going on in our model and some of the forces that we've seen over time that are important to point out.

So we can move to the next slide.

So lastly, this is the overall forecast that we have presented in this iteration of the Electric Vehicle Geographic Forecast, which in our basic condition puts the plugin electric

vehicle penetration rate at roughly 30 percent in 2025. And that is beating ZEV, as we all know. You'll see a lot of the penetration, the increasing penetration, coming in the next two years, 2017 being a year of significant improvement, and then 2018 being a year of --

MS. RAITT: We lost you, so hang on just one second here. What's happening? Okay. So, Scott, are you still there? We can't hear you anymore.

CHAIR WEISENMILLER: Okay. So just on logistics that you're --

MS. RAITT: Uh-huh.

CHAIR WEISENMILLER: -- as we try to deal with this part, we're running late, as you probably noticed. We had hoped to cover the PV issue before lunch. Obviously, this is an important issue. So I thought it would be better to come back fresh after lunch, than to try to squeeze it in, frankly. So just so you get a sense that, yeah, you can take a break at this point. A lot of people appear to jump up instantly.

And my presumption is that we can or should be able to compress a little bit the

comparison part later this afternoon. Obviously, it's very important, you know, how this stuff is allocated among utilities and, as we all know, even within the utilities. But I think we can make that a little simpler, because I suspect the utilities need more time to dig in to what's going on here. And I think it would be better to give, again, full attention on the PV issue, you know, a less crazy fashion than saying it's now 12:15, let's start and see how fast we can get through it or, you know, or how late we're going to run. And I've checked with both my colleagues, they seem to be happy.

So anyway, hopefully we're back soon on this.

MS. RAITT: Okay. I'm sorry, it sounds like we're just going to have to be cut off on this presentation. I'm sorry, Scott.

CHAIR WEISENMILLER: Well, that's good. You know, again, it's certainly been helpful to have this, you know, different perspective. It certainly raises some of the basic questions we've been struggling with by a simpler model. But again, you know, hopefully we'll have the reports filed on the record. And if he could --

I certainly encourage him to provide any written comments he wants to, although I suspect it's going to be more, here's my report --

MS. RAITT: Uh-huh.

CHAIR WEISENMILLER: -- which is fine.

So let's --

MS. RAITT: Let's have a break and come back at one o'clock --

CHAIR WEISENMILLER: Yeah. Exactly.

MS. RAITT: -- to talk about DG then.

CHAIR WEISENMILLER: Right. Okay. Thanks.

MS. RAITT: Thank you very much.

(Off the record at 12:05 p.m.)

(On the record at 1:05 p.m.)

MS. RAITT: Here we go. So we have Asish to talk about Self-Generation. Thanks.

*MR. GAUTAM: Good afternoon, Commissioners, members of the public. Kind of empty today. My name is Asish Gautam. I'll be going over the Private Supply Forecast for this IEPR. First, just a quick outline of my presentation.

I'm going to give a little bit of background info for this IEPR Preliminary

Forecast, and then I'll give an overview of the data and the methods and some of the changes we've made for this Preliminary Forecast.

And then I'll present the statewide results and then some of the next steps and take questions after that. So a lot of the changes we made for this Preliminary Forecast is due to some of the issues we faced trying to finalize the forecast in the 2015 IEPR.

Some of the issues we were struggling with back then was the possible changes to the NEM Program by PUC, and the possible expiration of the federal tax credit. And when we finalized the forecast back then we made some conservative assumptions on these two topics.

And of course, the PUC largely left the NEM Program unchanged and made some modest reforms, and then the tax credit was extended. And so our forecast became very conservative in outlook. And then in the 2016 IEPR we brought together forecasters from the utility, the National Labs, to talk about how they prepare forecasts for DG adoption.

And then we also explored the whole idea of the peak shift phenomenon. So let's see. So

here's the list of the different data sources that we've relied on to prepare the Preliminary Forecasts for DG this IEPR.

The first three gives us the install capacity for PV, and then there's also solar hot water. And then the last source gives us generation data, both onsite and export for large co-gen plants that we're including in our forecast.

So for this forecast our base year, our last historic year is 2015. And so at the end of 2015 we have about 7,000 megawatts of PV and CHP. PV was just roughly under 4,000 megawatts. We estimated total generation to be about 19,000 gigawatt hours.

So our PV makes 50 percent of the installed capacity. It's about one-third of the energy impact. The reason for that is the co-gen plants operate on much higher capacity factors. So they account for more of the energy.

There's roughly about an equal split between Northern California and Southern California when it comes to the PV install capacity; about two-thirds of the PV capacity install in the residential sector, about a third

in the commercial building sector, and then the other sectors, like ag and industrial.

Let's see. Some of the other changes that we've noticed since the 2015 and '16 IEPRs has to do with the large, national installers have kind of exited the market. And then also, with the decline in PV cost there's been a trend away from solar leases to more customer-owned systems. Okay.

So next, I'm going to give a little overview on the forecasting approach. Again, the approach we take is to look at customer response to a cost-benefit or economic indicators such as payback period. For this forecast we're also experimenting with a different metric called bill savings, and I'll talk about that a little bit later.

And then we use -- apply a Bass Diffusion Curve to trace out the additions over time. It's kind of a workhorse for us in regards of estimating future adoption. There are other entities that also used a similar kind of framework.

And we had three demand scenarios with varying levels of housing stock, growth in floor

space and growth in retail rates. And so we have some differences about scenario. Some of the changes that we made for this IEPR Forecast are mainly in the residential sector.

We've incorporated TOU rates and periods just for the IOUs and SMUD. The reason we focused on the IOUs and SMUD is because we actually have some load research data that we can use to apply the TOU rates and periods.

For the other POUs we're focused on using the annual average sector rates that's been prepared for this IEPR. We've also segregated usage by different consumption buckets so that we have low, medium and high-usage customers.

In prior IEPRs we only had one single profile for a climate zone. So we tried to expand on that with this IEPR. Let's see. One of the things that we noticed is that for this, the TOU rates that we have seen so far, the peak periods that move later in the evening, and so there is some reduction in bill savings.

Let's see. So most of -- I believe most of the peak period starts between 4:00 to 9:00 p.m. So it's not as coincident with the PV generation. Again, so when we followed up with -

- mainly with NREL from the last 2016 IEPR regarding how they approach forecasting for PV adoption, they did a survey and they found that bill savings was a better predictor of willingness to adopt solar.

And so we have reached out to them about some of the data and methods and they've offered some assistance to us in implementing their approach into this IEPR Forecast. And so for this IEPR Forecast, again, we're using monthly bill savings for IOUs and SMUD, and then we have an updated payback curve for the other utilities.

And then we didn't have a whole lot of updates from the commercial sector, but we did update our payback curve. So for a given payback we now have more adoption related to the payback curve we were using in prior IEPRs.

And this is based on an analysis that in the PUC's NEM tool that they had retained E3 for. So that's where we use it. One other change that we did make for this IEPR -- and there's always a call for more geographic disaggregation. And you've heard from Chris about the limits we have because of our econ demo data and other issues.

One thing we tried to do for this

forecast was to kind of pull out the POUs that get aggregated into the IOU planning areas. So the main reason for doing that was to have a more -- basically having a service area forecast, basically.

But we have reached some data issues, because a lot of the POUs that we have broken out don't have comparable load research data or were not in our last RASS or CEUS survey, and so we were kind of borrowing results based on the climate zone that they're in as a placeholder for this IEPR.

And depending on how future surveys and the database go forward, if we can get better data to characterize usage for those POUs that it would help improve our estimates there. And then let's see.

We spent some time on working on a data storage model, but this is -- we're not able to finish it in time for the Preliminary Forecast. I'm just going to give a quick overview of where we have gone with this.

So we're targeting three different segments. There's the standalone storage, storage for new customers paired with PV system

and not -- and then we're also trying to look at how all the adopters of PV systems may also be looking to adopting a storage system, as well.

There's a little bit on system sizing here. We really saw this coming out of the PUC SGIP data about a five-kilowatt and three-hour duration, some simple assumptions on round-trip efficiency and cost trends from the SGIP data.

Some preliminary findings just right now, standalone storage is -- has a limited potential because the peak to off peak ratios are not enough to incentivize standalone storage, but storage with PV happens to have the most promising potential.

For our setup we're looking at maximizing the -- or disbursing consumption from PV before charging up the battery storage system and trying to limit the exports. And then the discharge is based off the TOU rates.

Again, this is still an ongoing effort. And then we started a little bit on the -- for the commercial sector, but we haven't made as much progress. For there, we're looking to displace demand charge -- or save on demand charges.

Again, some other updates regarding NEM. We presented in the February Methods and Data Workshop about how we will come up with some options and present it to the DAWG and to our Joint Steering Committee.

So here are the three options we have. For the low demand we're assuming that the current NEM Program stays as is in the forecast period. In the mid demand we assume that your exports will be only credited at 10 cents a kilowatt hour.

The high demand is the same as the mid, but we added a $3 kilowatt charge, based on the capacity of your PV system. And we didn't find much opposition to our proposal in the DAWG or the JASC. And just given the uncertainty surrounding how NEM may change in 2019 due to maybe incorporating locational benefits and whatnot from the DRP.

So this seemed to be kind of a -- something that people are okay with for now. And then depending on how things go forward in future, PUC proceedings may have to kind of revisit that in the future IEPRs.

Oh, and yeah, we also updated assumptions

on the federal tax credit, which has been extended till 2021 and has a kind of a step-down. So first, we're going to present results for the statewide PV energy. So we see PV -- the estimated energy growing from 6200 gigawatt hours to between 29 to 35,000 gigawatt hours.

All three scenarios are substantially above the mid case from the 2016 IEPR. The differences among the scenarios are basically coming -- well, there are econ, demo and rate differences, but mainly, it's due to the assumptions surrounding NEM.

And then we also have much faster growth, about 13 percent a year, in the mid case relative to the -- 2016 mid case. And the next slide here kind of shows that -- the install capacity projections by the different planning areas.

You can see for the POUs we've found that the updated payback curves that we're using gives us very similar results, not similar, but very close to each other. And so the econ demo variables kind of dominate.

And so what happens is the -- we have slightly more PV in the high demand scenario than the low demand scenario. So it's kind of flipped

from the way we usually estimated results by the scenario. And the underlying capacity in total is about 17,200 megawatts to just under 21,000 megawatts.

About 70 to 78 percent of the capacity is in the residential sector, and we also notice substantial increase in additions in the more inland forecast climate zones because of slightly higher housing growth and commercial floor space.

One thing we noticed that, so when we do the update for the revised forecast we'll change our last history from 2015 to 2016. And what this means is that we'll still show some year-to-year growth, but we know for 2017, the first quarter installations are down quite a bit.

There's been a number of explanations offered. There were some weather-related issues in the beginning of the year so that, you know, that not enough installations were being done. Another reason was that installers may be trying to get more familiar with the TOU rates now that PG&E San Diego and just recently Edison have gone to the NEM 2.0, which requires customers to go take service on the TOU rate.

One other reason is that when the large,

national installers exited the market their impact is more felt now because they accounted for a lot more of the installations.

CHAIR WEISENMILLER: I think the other thing, certainly, is at one -- when you look at the data on installations it's very fragmented.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: And at one point the theory was for some of the people, like Solar City, was you know, we're going to try to blast forward now, get as much market share so we can become dominant. And now, it seems like a lot of them are dealing more with, oh, my gawd, cash flow, you know, that, you know, the goal was to survive, not to become the largest solar installer.

And so there has been some retrenchment. I'd be very curious to see the second quarter.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: Or third quarter numbers as you try to sort out the trends.

MR. GAUTAM: Yeah. So the PUC does have results for their -- for the IOUs up to the June of this year. And wherever you are right now is about where we were for all of 2014. So I think

we touched on this early in the morning about, you know, they may have been in kind of a rush to get under the expiration of the tax credit and maybe the changes in NEM, and that we may be coming back to more, I mean, normal rate of installations.

CHAIR WEISENMILLER: Exactly. I mean, that's where we probably need to -- again, right -- I mean, the reality, I remember we had a -- back in the biennial reports in the '80s we had one where I think we kept missing the gas forecast.

At some point it was just, I forget whether we jammed it down or jammed it up, but figuring whatever we were going to do it was going to be, you know, flip it from too high to too low.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: And then correct things. And so but yeah, I think there's at least a theory on pulling forward, now you get the markets -- all this uncertainty, you know. So trying to smooth your way through it is not easy.

MR. GAUTAM: Yeah. So --

CHAIR WEISENMILLER: But we're just trying to get to the best we can, and I assume the more -- better data we get going forward the more points it gives you at least to try to smooth through.

MR. GAUTAM: Yeah. Let's see. Here we have the statewide non-PV results. I'm only showing the mid cases, because our results for the high and low tend to be very close because of offsetting effects between them. For the co-gen you may have smaller -- higher floor space, but lower bill savings. So they kind of tend to smooth things out.

We have a higher mid case in this Preliminary Forecast because we have changed the -- we have a higher forecast for energy storage systems. And I'll show you in the next slide here. Again, so we weren't able to finish our forecasting tool for the energy storage systems.

What we're doing is simple trend analysis for this type of -- for Preliminary Forecast. We're expecting about 400 megawatts higher based on recent trends in the SGIP data. You can see in the early part of the forecast the mid case in the 2016 IEPR is a little bit higher, and this

was mainly concentrated in Edison's service territory.

And when we spoke with Edison's staff it turned out that there were some data issues with the SGIP data set that we used in the 2016 IEPR, and that's been corrected for now. So that kind of explains that, why we started a little bit lower relative to the 2016 IEPR.

One of the things that we've been struggling with storage is that it's a fairly recent technology to hit the marketplace and so we don't have that longer historical time series to kind of do a forecast. So that's something that will probably struggle for some IEPRs.

The other things that, taking some lessons learned from under-forecasting PV in prior IEPRs, we note that there's a lot of interest in storage. There's been dramatic cost reductions in storage. The PUC has revamped their SGIP Program to fund about -- the total funding is now dedicated to storage, about 80-85 percent of it.

And there were two other -- there was a bill floating around in the Legislature, SB 700, which would have created like an Energy Storage

Initiative modeled under the CSI Program, similar to the PV. I don't believe it was signed into law.

But again, there's a lot of strong policy support for storage, and it's one of the things --

CHAIR WEISENMILLER: The reality, too, is if you sold your PV to well-to-do, really, adaptors, you've got a great client list to go back and sell storage to. And so the -- you know, again, you can -- the easier customers then try to keep pushing along on some of the other stuff.

But it is associated with net metering. You know, depending on what happens on net -- you know -- basically, in the NEM proceeding I think it was -- Solar City was on one side of the issue and Tesla was on the other, with the Tesla Battery people saying, wait a minute, with net metering why is anyone buying batteries. So but I think you're going to see a healthy amount of up sales.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: Right.

MR. GAUTAM: Okay. For new construction,

this is really getting at what Chris had touched on earlier about how to approach the 2019 Building Standards, where basically, the ZNE option here. So we do do a forecast for new construction, but the question is how to account for a ZNE compliance scenario.

And as Chris had mentioned, we may try to do a baseline forecast and incorporate the additional PV into a managed forecast. One of the things that has come out with our conversations to the utilities is that our forecastings for residential sector is primarily focused on single-family homes.

There are some utilities that are expecting more multi-family units to be built than single-family. So we're going to have to revisit how we treat multi-family and -- for the revised forecast.

CHAIR WEISENMILLER: Yeah. The issue is more complicated than even we've got to. One of them is we've always assumed, Commissioner McAllister and I, that we cannot require solar on shaded roofs.

MR. GAUTAM: No.

CHAIR WEISENMILLER: For example. Now,

that gets to the question of how many shaded roofs are there.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: And but also the -- or just leave it as the Building Standards' proposals are evolving now and not getting -- you could certainly have follow up conversations with the staff on it, but it's getting more complicated.

MR. GAUTAM: Okay. Again, we'll be working with the staff on efficiency and utility stakeholders to -- probably in a DAWG setting to try to kind of hash some of these things out.

COMMISSIONER MCALLISTER: I wanted to just chime in on that. And you know, we had a little bit of this conversation with Chris in the morning, but certainly, you want, you know, anything, you know, I can do to help facilitate that conversation with staff and, you know, with Efficiency Division.

And it's becoming increasingly important to try to anticipate I think what's -- what may or may not happen. I think the PUC is in a position to inform this maybe more than we might assume in this building, because they are

actually starting to think about, you know, their 2019 Rulemaking on time of use, on opt out time of use for everybody.

That's going to go into the marketplace and probably impact PV uptake. And also, the NEM 3.0, you know, they got to get to that. So I think that the relative economy of solar in the new construction, but -- certainly, but also, just across the whole market is going to change in ways we don't necessarily know right now. So but it's going to happen early on in this forecast period, right?

MR. GAUTAM: Yeah.

COMMISSIONER MCALLISTER: So I think we kind of need to be prepared for that, and at least incorporate that into the narrative. On the new construction, yeah, I think the -- again, we're having a very robust conversation now with the PUC.

And so I think we need to, you know, make sure that we're listening to them and trying to anticipate what might happen. There's, you know, this cautious conversation is definitely gathering some steam in both conversations in Title 24, and over in their future rule-making

topics.

MR. GAUTAM: Okay. So the next slide is going to talk about some of the -- this makes it easier -- talk a little bit about rate reform and then the changes that, as we've seen, are an important step, but you know, in the future rate designs can take different dimensions.

Just going to think about, you know, we have so much renewables it's more than possible that our rates could reflect more wholesale prices, and especially in the solar generation hours that might not incentivize solar, but other load modifiers could benefit, like EV charging, battery storage charging.

And then Commissioner McAllister touched on the NEM 3.0 decision about how locational and system benefits could be incorporated. We also paid attention to the Suniva and Solar World trade case. The ITC has agreed to hear their complaint back in May. From the *1:31:10 of rate online is that if the plaintiffs get the ruling they are looking for, then most of the impacts may be felt more on the utility scale solar, and maybe large commercial industrial solar and maybe not as much in the residential and smaller

commercial, but that remains to be seen.

There's also the issue of the tax reform moving nationally. So it's kind of hard to kind of read right now, but I think the House plan has a 20 percent -- going back to the 20 percent marginal rates. So that could -- would impact leases.

But again, we've already seen a shift from leases to cash-owned systems. So I'm not sure what -- how much more of an impact that may be.

CHAIR WEISENMILLER: Also, solar is a global market.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: So China last year put in 30 gigawatts. They're going to put in 30 gigawatts this year. So in terms of economies of scale stuff --

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: -- you know, the costs are coming down. Now, there are arguments, in fact, President Picker and I got a letter from, you know, the pro tem, saying that, you know, again, there's a bunch of -- the question is, do people buy a lot of solar between now and

when the tax credits go away.

And that encouraged us to encourage the utilities, you know, this is more utility of scale, but I'm sure, as you know, the PV panels can go on the roofs, they can go utility of scale and there's probably going to be, again, some degree of real -- depending on what happens on tax credit reform, could be a real push on how do you get the stuff out the door.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: You know, between now and that point in time. And again, this weird jump up and then step down.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: Afterwards.

MR. GAUTAM: Yes. And then the third bullet about transition, just trying to get is there's been a lot that's been said about, you know, with the increasing competitiveness of the EG, what are we seeing, how do we see things like retail trace happening, moving forward in California.

A few months ago the CEC and the other agencies had a workshop on this very topic about how there's an interest by local communities to

care about where they get their energy from, and depending on how some of these policies go forward there could be greater incentivizing and more DG adoption.

Especially, there's been more focus on the disadvantaged communities. And then so it's depending on how -- what kind of funding opportunities have been identified. So I think there's some Cap and Trade type funding to be allocated to this area, but I think a lot of it is kind of up in the air right now, because there's a lot of -- in the various workshops that we've had there's a lot of institutional type issues like, you know, what do you do about multi-family in terms of overcoming some of the split incentive issues.

So then finally, I just want to leave with some of the next steps. We'll be updating our historical data for 2016, try to complete our storage analysis, and then we'll be taking a look at the comments that have been submitted for the Preliminary Forecast to try to incorporate it into the advance forecast.

And then we're also kicking off a project with NREL to prepare for the 2018 and '19 IEPRs.

They have developed some sophisticated modeling tools that we hope to incorporate and we think this will help better serve our stakeholders longer term.

Other issues. So there is a rulemaking effort to collect more interconnection data. I think the rule-making was filed with the overall real soon. So the comment period might have started already. We'll be coordinating with stakeholders in other venues and how the demand forecast is used, like the DRP and the IRP and whatnot.

We're also trying to coordinate more internally, especially with our EPIC staff, because they have released a number of solicitations about important forecasting of, for example, solar generation profiles, micro grids and whatnot.

So we're very interested in their findings and seeing ultimately how we can incorporate back into the demand forecasts. I think that was it for me -- oh.

CHAIR WEISENMILLER: Oh, okay. So a couple basic questions. I mean, one of them is the theme that emerges from your presentation,

and certainly our questions back and forth, is there's an awful lot of uncertainty on the PUC side.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: You know, as you've indicated, our base cases have been too low historically. There's been some perturbations. And all of us are scratching our head on NEM tax credit and everything else.

So at least, how do we reflect in a range of scenarios that uncertainty, you know, around the base case? You thought about that much?

MR. GAUTAM: Well, I mean, the scenarios that we have are more focused on longer term economic drivers, so not as much on things that would be unique to just PV or DG in general. To be honest with you, it is difficult to even try to think about what other factors can -- we can incorporate to do a sensitivity.

I mean, we have the standard things like retail rates, but we still can get -- have a handle on how rate design can evolve. We had just spoke earlier about how rate design could include other elements, such as more a reflection of wholesale prices, or maybe even moving away

from energy only to maybe demand charges, as well.

So there are, you know, a number of scenarios you can do, but to quantify the uncertainty, but I'm still struggling with the same issue on how do you isolate just the factors that impact DG only, as apart from all the other longer term drivers.

CHAIR WEISENMILLER: Just, I think, you know, obviously, the expected case is what we're going to use for planning.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: But I think part of -- if we can untangle some of the connection between policy and the range and the uncertainties, again, that's -- be helpful in the policy context. I guess the other one is, in terms of, you know, historic self-gen and co-gen, you know, that's -- in terms of a scenario which again, if anything, I am expecting not rapid growth, but some degree of shrinkage. And the question is, how well are we doing on picking up the shrinkage there?

MR. GAUTAM: So it didn't make it into my PowerPoint, but we did do a scenario, and I read

about for existing co-gen plants what happens if some of these plants can't get a contract for selling their exports back.

And so if plants cannot get -- so we worked with the staff in our supply office to develop some scenarios here. And so one of the assumptions we made was that if co-gen -- existing co-gen plants, as their contracts come up to expiration and they -- we assume they can't get a contract -- new contract, then we can have about a 50 percent reduction in the onsite generation.

I can't recall off the top of my head right now what that translates to capacity, but it could be substantial.

CHAIR WEISENMILLER: Yeah. Well, no. I know we're working on our tracking progress on SGIP numbers and staff's bringing a lot into this. It's not done yet, but basically just to reflect that, you know, while we have pretty aggressive goals for growth there, realistically, it's shrinkage.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: You know, certainly that's something which again has to be captured

in the forecast of what the expected case is.

MR. GAUTAM: Yes. So for our expected case for existing plants we assume that the level of generation that we have in the base year, we hold it flat. And the reason for that is because the bulk of the co-gen plants are in the larger industrial and mining sectors.

We don't try to forecast grown in there, but we do try to do a forecast for smaller scale co-gen, using the PUC's SGIP data as a source. And now that you bring it up, there is an interesting issue here regarding more requirements for generation projects, and that rebate program to start blending renewable gas.

And so it's one of the things we really did not have time for this preliminary effort to spend time on, but I think the way the PUC's approach -- the Rebates Program is set up, I think by 2020 you're supposed to be at about 100 percent renewable, some kind of 100 percent renewable gas instead of natural gas. So there could be a transition away from gas-fired -- natural gas-fire co-gen to digester gas or something else like that. But that's --

CHAIR WEISENMILLER: Well, certainly, in

the renewable gas workshop we had people were throwing around numbers like $15 a million for renewable gas, and not large quantities of it. So it's going to be pretty hard to make the economics, as well.

MR. GAUTAM: Yeah. Okay.

COMMISSIONER MCALLISTER: Yeah, just a couple questions. I guess I'm wondering sort of what's the latest on the quality of the interconnection data you're getting. Seems like that's kind of been an ongoing issue, mostly resolved as of, you know, last couple years, I think, but I just wanted to check in with you on that.

MR. GAUTAM: Yeah. So right now we are requesting monthly interconnection by ZIP Code for the major sectors through the -- or IEPR forms, but these -- what we collect is just simple capacity and customer count.

We still have to rely on the PUC's and the Commission data to tease out trans and install costs, things like that. So the changes that we submitted as part of our Rulemaking has a much more expanded fields that's been added.

We will not collect some of the other

fields that we think we'd be interested in, things like the cost and more system level details, but it is kind of a decision to try to treat outfalls -- try to get enough data that you can do something with, and not try to burden the filers too much, and it's still not clear to me if the (indiscernible) of this data like the system orientation total, things like that, so.

COMMISSIONER MCALLISTER: Yeah. So but the PUC's interconnection database, is that generally comprehensive in the IOU territories, or is it -- you know -- is there a process that guarantees that basically any interconnection gets into that database?

MR. GAUTAM: So the PUC's interconnection is limited to IOUs, which is the lion's share of installations. From what I understand right now is that their focus is on NEM PV, and so it does exclude the non-export PV.

If I'm recalling correctly, it's probably a difference about 400 or so megawatts. I'd have to get back to you exactly what the total size is for that segment.

COMMISSIONER MCALLISTER: But if it's getting -- if a NEM installation goes in, in an

IOU territory you're pretty confident that it's in that database, like if that's happening --

MR. GAUTAM: Well, we haven't had a reason to suspect otherwise yet.

COMMISSIONER MCALLISTER: Yeah. Well, no, I just -- well, it was just an issue, you know, as the rebates expired there was no automatic reason why that reporting would continue to take place, and the PUC has made the effort to have it continue, but I just kind of was wanting to, you know, get a status report on that.

I don't have any reason to assume that it's not happening either. I just was sort of curious.

MR. GAUTAM: Right. So there is a difference between data collected in rebate programs, then the rebates go away. But for interconnection it's a pretty standard procedure to, you know, request an interconnection permission before you can even install your -- or have it run.

COMMISSIONER MCALLISTER: Yeah.

MR. GAUTAM: So I think we have some confidence that it should be capturing all the

installations in there.

COMMISSIONER MCALLISTER: Right. Okay. Thanks. And then just curious about the market itself for rooftop. Are there -- you know -- the trends in terms of system size and things like that, are you -- sort of what is that looking like now?

And I just asked because, you know, the Title 24 context, which is likely to be driving PV on new construction to a great extent going forward, you know, the required system sizes are actually pretty small. And so just wondering how you're taking all that into account and what the system sizes you're working with are.

MR. GAUTAM: So if I'm recalling from the data sets that we looked at, for residential it's still the dominant size about five or so kilowatts. There was an interesting report that came out on GTM about how TOU rates may incentivize larger system sizes to try to take more generation in the later evening hours.

So you know, it's kind of up in the air for getting how it may evolve going forward with all these other changes in the play, in the mix.

COMMISSIONER MCALLISTER: Yeah, okay.

I'll stop there, I guess. The next couple of years are going to be really interesting. I mean, I think we're going to be able to have a lot more detailed, or at least a lot more informed conversation in 2019 as we sort of get to the endpoint of some of these discussions. So great. Thanks a lot for all the work.

MR. KAVALEC: I want to change the order a little bit here, because our friends from Edison have an early flight to catch. So I wanted to go ahead and do the Edison presentation, and then we'll go back to our presentation on rates.

COMMISSIONER MCALLISTER: That sounds fine.

MR. KAVALEC: Okay, our first utility planning area today is Southern California Edison. And some highlights on the inputs and assumptions that went into the Edison forecast.

Population growth of around 0.7 percent per year, which is a little bit lower than the State average of around 0.8 percent.

Growth in number of households a little bit higher. Per capita income growth of 1.86 percent per year which is also a little bit lower

than the State average.

A little bit lower than half a million light-duty EVs in our forecast projected to be on the road in the Edison territory in the mid case. More than half of those are battery-electric vehicles. The rest are plug-in hybrids. And that gives us electric vehicle consumption of a little over 2,000 gigawatt hours in 2028.

Behind-the-meter PV, installed capacity of 6,300 megawatts in 2028. And as I mentioned earlier, our EV and PV forecasts are lower than Edison's, and they can talk about that a little bit.

Then, load-modifying demand response impacts of for Edison of a little bit less than 100 megawatts in 2028. Again, that's pricing programs, like critical peak pricing, peak time rebates, as well as permanent load shifting.

So, for a little change of pace, what I'm going to show here is consumption and peak end use load because those are the basic building blocks of our forecast. Our sector models forecast consumption and then we adjust that to get to sales, and then net energy for load.

Then our peak model forecasts end use

load at peak, meaning the total end use load regardless of generation source.

So, looking first at consumption, for Southern California Edison, very close in terms of the mid cases in terms of growth. And then peak end use load. So, really, one of the benefits of doing a preliminary forecast is that you'll sometimes catch things that look suspect that you want to look into more.

And in this case I'm a little leery of this jump downward between 2016 and 2017 in the Edison service territory for peak end use load. It could just be that we had unusual low load factors in 2016. Or, it could be there's an issue with the model's scaling and calibration routine. But anyway, this is something I want to look into and fix, if it needs fixing, for the revised forecast.

Okay, so we have a consumption forecast, then we take self-generation energy amounts and we subtract that to give us sales. And you'll see the flatness of the sales for Southern California Edison, average annual growth around 0.3 percent.

And then to get to our net peak, which is

the peak that has to be served by the utility, we start out with the purple line, our peak end use load that I showed you earlier. You add in line losses. You go up to the green line, which we call gross generation. And from that you subtract off self-generation, as well as that small amount of load-modifying demand response, and you get to the net peak which, as you can see, is flatter than the peak end use load because of self-generation.

You will see this for all the planning areas, residential consumption via electric vehicles and plug loads is growing at the fastest rate among the sectors, followed by commercial and then industrial.

The commercial growth is relatively low for Southern California Edison because the forecast from Moody's, for commercial employment is relatively low, and that's the main driver.

So, my second bullet there, with less growth in commercial, Edison's consumption grows slower than the State average in the mid case.

And the end-use load peak grows faster than consumption because of this suspect drop that I talked about earlier. And also because

residential is growing at a much faster rate than the other sectors and residential tends to be peakier, so that drives up the end-use load at peak.

Okay, comparing our -- well that should say Edison, obviously. Comparison of our mid case with SCE, submitted for that IEPR. As I mentioned earlier, Edison has much higher electric vehicle and PV forecasts. But aside from that, and taking into account that their forecast incorporates uncommitted efficiency and ours doesn't, our sales forecasts are very similar.

The peak forecasts, as I also mentioned earlier, are not directly comparable at this point because Edison's talented analysts have incorporated the peak shift, which hasn't been included in our forecast, yet.

So, I will ask Hongyan, from Edison, for comments or response? Does she want to come up here?

We will have a quick presentation here in a moment, when we load it on.

MS. SHENG: Well, while the file's being loaded, let me just introduce myself. My name is

Hongyan Sheng. I'm the Manager of load forecasting at Southern California Edison.

First of all, I'd like to thank Commissioners for providing this opportunity to make comments at the meeting. I'm very enlightened to hear some of the comments you made earlier on with regard to how we need to work together to explore the potential for future PV load growth. I'll be happy to stay engaged with the CEC forecasting team and other stakeholders to ensure that we get to a reasonable consensus for you.

I'd also like to thank the CEC forecasting Team, and Chris, for working really collaboratively with SCE forecasting teams throughout the IEPR forecast process. We not only learned a lot from each other, but also I understand much better as to how we may close some of the gaps we're seeing in our forecasts that we will show later on.

But, hopefully, by highlighting some of the differences we see today and also understanding what's driving those differences, we can feel much more positively about how we can narrow those gaps, you know, toward the final

forecast.

So, first I'd just like to highlight, at a high level, the major areas that we see, you know, in existing forecasts. One of the main differences, as Chris highlighted, is right now SCE's forecast and CEC's are not directly comparable. Peak shifting drives significant differences between our long-term peak demand forecast. So, we have a slide that we'll put on later to highlight how much we think the impact, how much impact there is between the forecast, what we consider the shift, in fact, compared to the projecting without considering the peak shifting fact. So that will, hopefully, give us a sense of how much that will help reduce the differences we see, you know, in existing peak demand forecast.

So, as I mentioned, we see the differences in our peak demand forecast, but we think most of that will be addressed through the peak hour shifting impact that I believe Chris and his team work on to incorporate in the final demand forecast.

Another area driving differences between our forecast is coming from the future projected

EV load growth. And I think Navigant's provided some high-level overview of the methodology that SCE had relied on. But we'll provide specific views on the number of differences.

Another of the areas that we identified is solar PV. And this time the main drivers for the differences not necessarily comes from the modeling between CEC and SCE, but rather it's really driven by our assumptions about future expected compliance rates, in the nature of the Title 24, which we view it's likely to a mandate with high compliance rates.

And I think the CEC forecast, the compliance rate assumption is much lower. So, we'd like to provide some highlight around that.

CHAIR WEISENMILLER: I think actually, yeah, that would be good. I think the things we really want to know, you know, is one, the shaded roof question.

MS. SHENG: Yes.

CHAIR WEISENMILLER: Number two, the sizing of what you're assuming on the PV part and compliance. All three could be differences.

MS. SHENG: Yeah. I think those are totally valid questions. SCE would like to work

with CEC Efficiency Division, CEC forecasting team to continue to refine those assumptions.

As far as to the shading limitation requirement, we have looked into NREL's, the National -- you know, the Renewable Lab. NREL's recent latest study, basically the shading requirement for solar roof installation has reduced significantly. Meaning that we don't see much constraint any more from the shading requirement for the solar rooftop installations.

However, in terms of sizing, I think SCE will need to continue to explore the proper sizing assumptions to make for the future new home, you know, construction. What's the right sizing? Potentially, for multi-family, the sizing requirement will be more limited compared to a single-family.

So, I think currently SCE, you know, has not really differentiated single-family versus multi-family in terms of the potential sizing differences in the requirement. But we would like to work with the CEC team closely to make sure that some consensus view in terms of what are the proper sizing assumptions, essentially differentiated by single-family and multi-family.

CHAIR WEISENMILLER: I think the other thing we struggle with is from a different proceeding is that generally, you know, low-income -- SB 350 low-income barriers effort, we've been told that, you know, there's very little solar in rented housing. And so, trying to figure out, again, what your split is for rented space and how that affects -- obviously, we're all trying to figure out ways to improve that. But at least at this point, you know, for low-income/rental that's not an area of high solar penetration at this point. And difficult to move forward in the future.

MS. SHENG: Yeah, definitely, I think that's why I think when we look at the specific details we would try to work closely with CEC Efficiency Division, and also our SCE internal ZNE experts to make sure that we line up with the best assumptions.

So, the first slide here is really just highlights and, hopefully, help us to understand that by incorporating peak shifting impact it could mean significant differences in our long-term projection.

What we look at here is by 2028, the top

line reflects the SCE existing peak demand hour work. The dashed green line, below that, reflects our hypothetical peak demand projection results, incorporating peak shift demand and peak shift impact. So, the magnitude of impact could be as much as 2,000 megawatts.

So, hopefully, when CEC gets incorporated the peak shift impact in the final forecast, our peak demand forecast gap will be much reduced.

The next slide shows, if we can go to our load EV, electrical vehicle forecast. Here's the number of vehicles we are looking at that we expect to be on roads by 2028. SCE right now forecasts significantly above CEC's current project. We're looking at about 1.8 million light-duty EVs on the road by 2028, compared to CEC's about half-a-million or so, and there's a big gap there.

But we also look at CARB's scenario where, you know, CARB is looking at by 2030 we see -- let me see, I think we have a backup slide here. Eventually, we're looking at about 4 million or so EVs on the road by 2030 or so.

So, our longer-term trajectory gets really close to CARB's scenario. However, SCE's

a high look of acceleration happening in the early ten years, rather than the later part. And we even see there's more upside risk to the very longer term, beyond 2030, if the early acceleration occurs there's more upside risk to our current forecast for the longer term. You know, potentially we could see more EVs on the road.

So, in terms of how we are looking at the confidence around our EV load forecast, we really are -- you know, as Commissioner, you mentioned about there's news coming every day, and it's just fascinating. What we'd like to highlight here is former areas of key barriers that we look at for EV, electric vehicle adoption. And, you know, day by day we keep monitoring the changes as we got to, you know, how these barriers get addressed.

And so, what we highlighted here is, first, in terms of technology costs, really we're seeing battery costs not only decline significantly in the recent history, but continue to decline based on the most vendor projections.

At the same time we, you know, look at the strong incentives existing to date just

provide tremendous economic basis for customer adoption.

Another key areas of barriers that we look at is the infrastructure. As most of you know, the utilities within California are making significant commitment to expand the charging infrastructure to help bring forward more electric vehicle adoptions, and so that we can achieve more clean air goals for the State.

And that is really ramping up. But, potentially, we have a lag behind our EV growth. Eventually, we see a strong feedback loop, you know, from expanding infrastructure to push for more adoption in the marketplace.

The recent Volkswagen settlement funds will be utilized to help expand the infrastructure, as well.

The third areas of barriers we look at is, really, all the actions taken by manufacturers, and all the nations across the globe. We've just been hearing different, you know, existing news every week, it seems like, from the key car manufacturers about different product offerings, and different (indiscernible) in terms of limiting the (indiscernible) car

sales by a certain time.

It seems like, you know, there are different driving forces to make -- you know, it could actually be a goal, just like the vehicles that we have today.

And then the last area I think which is really, really key to the eventual electric vehicle adoption is our consumer awareness. We recognize there's a lot of funding that's provided to target EV, including disadvantaged communities, to raise consumer awareness about electric vehicles. All the way up from top DOE funding to the programs. All of those I believe that will become also the additional vehicles for facilitating our consumer adoptions in the future.

So, as we look across all of these key barriers, how they're being addressed, you know, in the real world we're really feeling very positive about the future accelerated EV adoptions.

COMMISSIONER SCOTT: I want to highlight what you have just said. And I think that the discussions that are going to take place in the Demand Analysis Working Group coming up will be

really important to make sure that this type of information is something that everyone is thinking about and considering. And I'll be looking forward to seeing what's in the PG&E, and SMUD, and SDG&E, and LADWP plans as well.

And what you're showing also, on the line previously with the -- I think it was actually in your -- oh, no, it's in this one, too. With the scoping plan, also underscores the importance of the discussion that the Joint Agency Steering Committee will have in this space.

MS. SHENG: Thank you. I also feel excited about your initiative about getting all of the stakeholders together to help analyze for the future potential EV load growth.

So, the last area I will highlight quickly is with regard to the nature of zero net energy compliance. We work closely with our internal analyzing experts, who then work really close with CEC Efficiency Division. In our view, you know, we really see the strong -- the upcoming implementation of the ZNE will push strongly on the compliance part. From the CDs, you know, I see really close.

And as well as, you know, the nature of

the compliance, basically our experts see that it's very easy for any inspector to check on whether there is a solar PV rooftop system installed or not. So, different than other types of compliance, we believe the solar rooftop system requirement will be very easy for anybody to check on.

So, in our view, the compliance rate will be pretty high. And we also consider that from technical potential perspective, both single-family and multi-family would be able to meet the roofing requirement for solar PV system installations.

So, we have assumed not just, you know, for single-family, but also for multi-family starts in our territory for the longer term. About 90 percent of them will have solar rooftop systems.

So that drives mostly the difference between SCE solar PV forecast and CEC's current solar PV forecast. Meaning that SCE's forecast is much higher for the longer term because we are assuming much higher ZNE compliance rates. And also, we are applying it to all of the housing starts, including the multi-family starts. But

definitely, we have more work to do in terms of refining our sizing, you know, assumptions and other restrictions.

COMMISSIONER MCALLISTER: So on that point, you know, again we had somewhat this conversation at the statewide level, with Chris earlier, and Asish.

But I guess in terms of where, you know, at the actual regulation the Building Code is going to land, I think, you know, please make sure you're keeping in touch with the staff in the Title 24, in both divisions, I think in the Title 24 and in the forecasting team about that.

And multi-family I'd say, you know, that's probably less certain just because there's likely to be a hard requirement in that sector, at least for this go around of the update of the Building Standards.

And then, I think on our side -- so, you've got a bunch of local governments down there that are looking at requiring PV, or they're focused on net zero or, you know, the different versions of this. And so I think it behooves us, on our side, to keep track of that. So, if you can help us do that and sort of keep

track of the local governments that are pushing the envelope on this, then I think we'll get the local piece of this in alignment, as well.

MS. SHENG: Definitely. We've been trying to engage with both the forecasting team at CEC, and then we just brought some conversation between our ZNE experts and the CEC Efficiency Division. And, hopefully, we can rely on both their expert judgment to help us shape up the final assumptions.

So, that's the areas that I would like to highlight at this time. You know, as we highlighted here, I believe most of these major area differences, as we understand what's driving those differences we have a strong belief that we can really bridge those gaps by working closely with CEC forecasting staff and bring out the most consensus assumption for the final forecast.

CHAIR WEISENMILLER: Thanks for coming up today.

MS. SHENG: Thank you.

MS. RAITT: Thanks. So, I guess we'll go back to Lynn Marshall to discuss electric rate scenarios and an update on time of use analysis.

MS. MARSHALL: Okay, good afternoon. So,

I have two topics I'm covering today. An overview of the preliminary rate forecasts, which are an input into the energy demand sector models and into the self-generation model. And then I'll give an update on work in progress for estimating time of use load impacts for the revised forecast.

So, just a brief recap. So, in the context of the electric rate forecast, we have the high energy demand/low rate case, we have natural gas and carbon prices, best investment in infrastructure, and we have higher demand so that the average distribution rate tends to be lower.

And then on the low energy demand case, we have high natural gas and carbon prices and more investment in infrastructure.

Okay. So, in addition to the staff common case inputs, like the natural gas and the carbon credit prices, some of the key inputs are the utility-specific energy and capacity supply information and the utility revenue requirement projections. So, this rate forecast was prepared back in April. Much of that data hadn't been submitted, yet. So, for this preliminary rate forecast I haven't been able to review and update

all of the revenue requirements.

Those data are all now filed, so for the revised forecast I'll be going through all of the different revenue requirement components, including the new AAEE, using the new preliminary demand forecast. And then, we'll have a natural gas price forecast by then.

So, these are the high prices I used. The mid-case, the starting point is lower. However, we still have a significant ramp up. So, in the mid-case I think it increases by something like 80 percent by 2020.

In the high price case it doubles by around 2019 to 2020. So, this forecast has a significant ramp up on gas prices that's going to affect the wholesale prices.

Now, the NAMGas team has continued to work on their modeling and I've been told they're expecting the revised gas prices to be lower overall.

For incremental renewable purchases I have updated PPA prices for wind and solar from the staff Cost of Generation Model. So, they're starting off at something like current costs. And then, as the production tax credit and

investment tax credits are ramped down I see prices going up.

So, those are used to value incremental purchases that utilities need to meet their RPS target.

Okay, the carbon allowance price forecast I haven't changed since the February workshop, but I did want to bring these up just to say I looked at the language of AB 398 to see how that will affect it. The most significant implication would appear to be the addition of price containment points. So, I think that's mostly, I think, to affect a high price trajectory and not necessarily the end point.

The Haas Institute actually has done a working paper looking at that type of market regime with the price containment points. And their assessment was it actually lowers the probability of reaching a price cap. So, we won't be able to -- I don't think Air Resource Board will have new, proposed rules in time for this IEPR, but we'll follow that.

So putting those pieces together, I also looked at implied heat rates of recent Cal-ISO energy prices from 2016 and the early part of

2017. And it was in the neighborhood of 7,300 Btus per kilowatt hour. So, that's reflecting all those hours when renewable are along the margin and depressing prices. So, I used that as the heat rate.

So, we have a lower overall set price forecast compared to 2015 forecast, but actually we've got a higher rate of increase by the end of the forecast reflecting the gas prices.

So, putting that all together, at the statewide level we have the mid-case residential statewide rates. A slightly higher rate of growth, 1.2 versus 1 percent, and kind of the overall driving forces are the overall lower level of sales which pushes rates up.

The transmission costs for jurisdictional rates increase much faster in the recent years than was assumed in that forecast, so I'll have to reevaluate that for the revised forecast.

And then we have the rising wholesale price and some increases in the renewable prices.

Similar factors on the commercial side. A higher rate of growth, one and a half percent versus 7/10ths of a percent in the CED 2015.

Okay. So, as we look at the IOUs we have

some various kinds of overarching factors and then some utility-specific issues that I'll point out. And as I said, a lot of the assumptions are going to change for the revised forecast, so I'm going to point out already that things are going to be different.

So, in PG&E residential rates, in the PG&E forecast we have Diablo retiring. I did not make any assumptions about preferred renewables to replace Diablo. Now, since then staff has developed a set of common case assumptions for how to handle the Diablo retirement. So, in the revised forecast I'll be adding more energy efficiency, and some wind, and geothermal, and phasing those in around 2024. So, that trajectory will look quite a bit different.

And then a similar story on the commercial side. So we have 2.2 percent annual growth rate in this forecast, so that should come down quite a bit, and probably closer to the CED update May case.

In the SCE area, so SCE has a number of balancing accounts and some tax refunds that they've been paying back to customers. And as those get amortized, I think around 2017-18, then

that's causing that kind of spike up in rates. And then we have a general rate case that's just getting started with -- I think, the potential implications on these capital expenditures are pretty large there, so that's something we'll look at. So, it kind of drives the range of the high/low, in addition to the variation caused by high and low sales.

So, you know, in the high demand we have almost flat rates versus a 4 percent in the low demand case.

And similar story on the commercial sector.

So, San Diego, I'm wondering about this jump up. They have a number of things going on. They have a delayed general rate case, increased -- pretty large increase in the transmission rate. They also have this balancing account to account for residential cross-subsidies. That's called the Track. And so there was, in 2017, a large increase in that component, so that hit the residential sector pretty high.

That said, I think when I calibrate to move to the 2016 historic year that 2017 .03 is going to come down a little.

Commercial side, and I should point on the commercial rate San Diego has the highest percentage of direct access, so this is actually a weighted average of IOU customers and direct access customers. So, the trend looks a little different there.

So, do you all have questions on the IOUs or you want to wait?

CHAIR WEISENMILLER: I just want to observe, I think they have been using the constant IER, or 7,300. The one disadvantage of it is we're adding more and more renewables all the time, which is driving -- you know, or increasing the efficiency of the grid, I guess, which is driving the heat rate down, you know, blah, blah, blah.

So, there are some forecasts that I've seen, you know, and it would be good to sort of see if, basically, anyone has a forecast out that captures some of that effect, as opposed to just holding it constant.

MS. MARSHALL: Yeah. Actually, PG&E has a methodology where they use a regression methodology to estimate prices of function of the heat rate. So, that kind of approach I think is

worth looking at. I didn't have time to go down that path for the IEPR but, yeah, I think that would be a -- there's other methodologies we could use to capture that effect, so we'll keep looking at that.

Okay. So, LADWP, they're about the second year of a five-year rate action. And, actually, the rate increases, as implemented, prove to be actually set lower than what they had originally proposed.

And then beyond that, these are -- we're using scenarios from their analysis that they did as a part of that rate case. So, these have not changed a whole lot from the previous forecast, except to true up to the adjustments to the actual rate actions.

And then, NCNC that's mostly SMUD. So, they have on the residential side I think they have a one and a half percent increase in 2018, and then 2019 they're holding rates flat because that's when they will transition residential customers to time of use.

Then on the non-res side, there was two years of a one percent only increase. And mostly those rate increases are to fund, I think,

additional capital to support infrastructure investment. So, that keeps their rate increases pretty low.

All right, so I'm going to use on to time of use, unless you want to have any more questions on that.

Okay, so the PUC has approved rate designs for the IOUs to use for the 2018 default pilot. That's our best estimate of what the actual default rates will look like in 2019. Most of those are a 4:00 to 9:00 peak period. A couple of them have three periods. They are testing some other rates and, generally, the IOUs are moving towards offering multiple optional time of use rates. But what I'm modeling here at the rates that customers are most likely to be defaulted on, but there are other options for customers.

SMUD, the SMUD board has also voted to implement a standard, what they call time of day rate, in 2019. And that will have a 5:00 to 8:00 peak period. So, they're on the same timeline as the IOUs.

So, key assumptions for this. We had a couple of meetings with the DAWG on this topic,

including CPUC staff. So, the assumptions I'm using at this point, I'm starting with price elasticities from the Statewide Pricing Pilot.

I'm actually using those unadjusted elasticities for load modifiers to use in the self-gen forecast, on the theory that -- so, that's an opt-in study, reflecting customers who are engaged and aware that they're on a time of use rate. And people who are installing PV are probably also engaged enough and aware to figure out that they're on a time of use rate and how it works. So, those are what I gave to Asish.

To prepare the default load impacts, there's some useful insights that we've gotten, that I've discussed with the DAWG on the results of the current opt-in pilot. And then, importantly, we need to reduce the load impacts using the SPP elasticities to account for the fact that default customers, you may have many of them who pay no attention or don't care that they're on a time of use rate.

So, in the SMUD pilot, the load impacts were about -- the default customers were about two-thirds of the opt-in customers.

And then a final assumption is what

percentage of the population is actually going to be defaulted? SMUD is going to be almost everybody, anybody who doesn't opt out.

But for the IOUs, they have some statutory exclusions. The largest category there is the requirement that there be 12-months of quality interval data. So, the IOUs have estimated when you put together all of the excluded categories that may be 65 percent of residential customers will be eligible to be defaulted.

All right, and then another key characteristic is in the rate design what's the ratio of the peak to the off-peak price that really drives demand responsiveness in the model?

So, we're starting off with the adopted PUC rate designs. And keeping those constant in the mid and the high demand case, and then in the low demand case we're letting that peak to off-peak differential increase. So, that drives increasing responsive peak impact reductions over time.

And then the other aspect we're varying on the scenarios is kind of what I've labeled here, the engagement adjustment that lets you

reduce load impacts to account for kind of the unawareness or unengagement of default customers.

So, in the mid case I'm using the SMUD result. And in the high demand we have higher reduction to the load impacts. And in the low demand/high engagement I have 10 percent lower reduction. Okay.

Now, I have some kind of preliminary snapshot of work in progress. In these cases I haven't varied the number of participants, so this is kind of a comparative static step here. For the next DAWG meeting, I think I'll also do some additional scenarios that vary the participation rate.

And then the caveat that all of these results will change when I use the preliminary demand forecast and account for AAEE.

So, these are peak period impacts over the peak period. So, this is the peak period is 4:00 to 9:00 and these are the average impacts over that time period.

So, you can notice that for PG&E, much lower level impacts than SCE. The PG&E, that rate has a much lower peak to off-peak ratio than the Edison rate. PG&E's around 1.3 and SCE is

about 1.8. Right, so that really you see a difference in the results there.

SCE also has more cooling degrees days, generally. So, on the SCE side you can see as you increase the peak to off-peak ratio in that low case it drives results up close to 250 megawatts.

These are average peak periods, so once I have translated those to an hourly shape, you'll get a higher -- the absolute impact will be higher, okay.

So, then on the bottom row we have San Diego and SMUD. And again, San Diego has a peak to off-peak ratio of about 1.6. That's relatively low for a time of use rate. SMUD's is 2.4. So, you can see the difference in impacts there.

So, looking across months, and I've got to put a couple caveats in here. So, I'm using elasticities from the Statewide Pricing Pilot. They only had one year of data for the non-summer months. It was not that large of a sample. So, these all need to be reevaluated once we get a full year of load impacts from the ongoing default. That will give us a real solid basis of

comparison for what the non-summer month load impacts look like.

And also, that study didn't include any three-period rates, so I'm using it to model these three-period rates. How well, how appropriate that is I'll be able to judge when we get the next load impact result from the opt-in pilot.

So, the other thing to notice about this is this suggests that we have overall some energy conservation going on. Right, the peak reductions are much bigger than the off-peak increases. The summer load impacts from the opt-in study did suggest that we have conservation. But again, we need to look at the whole year of impacts before we can be certain of that.

The SMUD Pilot Study I think did not find any conservation. It was all switching between periods.

And then you can see, right, the load impacts are really driven by cooling degree hours and AC saturation so a much lower level of reductions in those non-summer months.

So, for San Diego and SMUD, kind of similar results. San Diego has a -- they both

have three period rates. And again, when I get more results from the pilot study I can evaluate how well this is modeling.

You know, in the San Diego, the San Diego three period rate there's a rate just like this in the Default Pilot Study. And economics would suggest that people reduce in the mid-peak, but that is not actually what they did. They actually conserved. So, San Diego has a relatively high mid-peak rate. You'd actually expect some load reductions.

That's not actually what they did. So, there's some counter intuitive things, so we'll have to look at all of these together, and discuss that with the DAWG to see what assumptions we finally want to make for the final set of forecasts.

So, next steps. So, as I mentioned, I'll go through the -- I think that will come out in August and September to look at the full year load impacts in more detail, and then implement the hourly load data that Chris will need for the hourly forecast. And then, we'll be having another workshop with DAWG to talk about the specific assumptions we want to use.

So, any questions?

CHAIR WEISENMILLER: No. Thanks.

MS. MARSHALL: Okay.

MS. RAITT: Okay, so back to Chris Kavalec to discuss Los Angeles Department of Water and Power's forecast.

MR. KAVALEC: Okay, on to the remaining planning areas' forecasts. This slide gives a summary of the growth rates for the different planning areas, the big five. Actually, for SMUD the planning area is Northern California non-CAISO, but we really don't have a representative for that area to comment on the forecast.

So, we're presenting SMUD's forecast, which is most of that planning area, anyway.

So, looking at the mid cases for sales and peak, you'll see that the highest growth rates come in the two POUs, LADWP and SMUD.

And the reason for that there are, in relative terms there is less PV adoption. So that's a reduction to sales and peak impacts compared to the IOUs.

Also, because LADWP has, in relative terms, a fairly high EV forecast for its size. And SMUD has, among the five utilities here, has

the highest projected growth rate in population, so that drives up its sales and net peak.

Okay, LADWP, population growth is the lowest among the five planning areas. But per capita income growth is the highest. And this is something I want to check on with Moody's for the revised forecast because this seems high to me, compared to previous estimates. And LADWP, in doing their forecast, is using a much lower rate coming from UCLA. So, I want to check on this.

A couple hundred thousand light duty EVs on the road in 2028, in the mid case. More than half of which are battery/electric vehicles. Leading to consumption of around 860 gigawatts in 2028 from electric vehicles.

PV installed capacity of 678 megawatts in 2028, in the mid case.

Consumption, you see that big difference at the beginning of the forecast between the mid case from 2016 and the new mid case, or all three new cases. And that's coming from a correction to the sales, the historical sales number. We had a much higher number initially filed through QFER, with us, but that number has since been corrected downward. So, that's the reason for

the difference.

And again, peak end use load, a similar growth in comparing the two mid cases. A little bit higher in the new mid case and also a little bit higher for consumption in the new mid case because of the high income growth.

Again, adjusting our consumption to get us down to sales by subtracting out self-generation energy, and we're left with a sales curve that's upward sloping for most of the forecast period. Unlike what we'll see with the IOUs and that's because of less, in relative terms, self-generation affecting sales.

Going from our peak end use load, in purple, adding in losses, giving us gross generation. And then, subtracting off self-generation at peak gives us the dark blue, with triangles. And that's our net peak forecast for LADWP.

And again, upwards sloping, unlike the flat forecasts you'll see for the IOUs because of less relative PV adoption.

Once again, the residential sector leading the way in terms of consumption growth via EVs and plug loads. Commercial second. And

then we have industrial flatter or declining.

Because of the relatively strong commercial growth, relative to the other planning areas, and relatively high EVs, as I mentioned before, LADWP consumption grows faster than the State average in the mid case.

The residential end use load at peak grows more slowly than residential consumption. So, total end use load at peak grows slower than total consumption and that's because you have a lot of EVs on the consumption side that don't have much impact on peak.

Comparing our forecast with LA's, submitted for the IEPR, LADWP has more EV consumption and lower PV, although not by the significant margins that we saw with Southern California Edison.

Aside from this, there are really not significant differences we could find in our forecasts, both on the peak side and the sales side. And plus, LADWP is in the midst of developing their new forecast that we can compare with when we do our revised forecast in the fall.

So, because we're so similar and because LA's developing a new forecast, I don't know if

they have any comments. But I'll just ask if Bingbing or Mike Cockayne are on the phone and want to make some comments? And if so, please raise your computer hand.

Okay. So, moving on to PG&E. Population growth of almost 1 percent a year, a little bit higher than the State average. Per capita income growth of 2 percent a year, right on the State average.

Among the planning areas, the highest number of light-duty EVs on the road. Again, more than half of which are battery/electric vehicles. Giving us EV consumption of 2,400 gigawatt hours in 2028.

Behind the meter PV, 7,750 megawatts in 2028. And as mentioned before, we're a little bit lower than PG&E on the PV side.

And load-modifying demand response of a couple hundred megawatts by 2028.

We started off slightly lower than looking at the mid case from 2016, in red, because of the additional efficiency program impacts at the beginning of the forecast period. But after that growth is similar out to 2028, between the two mid cases.

Peak end use load, again similar growth out through 2028. So, we end up almost identical to where we were in 2016 by the year 2027, comparing the two mid cases.

Converting from consumption to sales, again, we're subtracting off around 20,000 gigawatt hours of self-generation, of which around 13,000 comes from PV. Giving us a relatively flat sales line. A growth rate of around .38 percent per year from 2016 to 2028 for sales.

And then converting from a peak end use load to net peak, we add in our line losses, subtract off our self-generation, 4,300 megawatts worth, of which more than half comes from PV. Ending up with a relatively flat forecast for peak demand through 2028.

Commercial, again, the same order, the residential followed by commercial and industrial. A relatively strong, both commercial and residential growth. So, PG&E's consumption grows faster than the State average.

And because residential is growing as a

share of total consumption, with its fast growth rate, the end use load peak grows slightly faster than consumption because it's becoming peakier.

Comparing our forecast with PG&E's, submitted for the IEPR, PG&E has higher EV and PV forecasts, although not to the same extent as we saw with Edison.

Aside from this, and accounting for committed versus uncommitted efficiency, PG&E has a higher sales forecast, which we've narrowed down to three things. Faster growth in the industrial sector, faster growth in the Ag sector. And these come from differences in the way the models are specified that predict industrial and agricultural growth, because I think we're using basically the same input data to do this. It's just a matter of how the models are specified. So, we'll look into that some more for the revised forecast.

And the way that efficiency is accounted for, PG&E uses an econometric model. And it's always a little bit subjective in determining how much efficiency is already embedded in the forecast. Because econometric models are carrying out past trends.

So, I think because of the difference in efficiency accounting between our modeling system and what PG&E does, that accounts for some of the differences in the sales forecast.

And as with the other IOUs, PG&E has incorporated the peak shift and, therefore, we can't at this time compare our peak forecasts directly.

COMMISSIONER MCALLISTER: Chris, how difficult is it going to be to sort of tease those pieces out, like between now and the final? Right, the EE you just talked about strikes me as a little bit difficult to kind of resolve.

MR. KAVALEC: Yeah. And so, first, I need to get more familiar with their methods and see how different they are.

COMMISSIONER MCALLISTER: Okay.

MR. KAVALEC: And maybe they have some insights in the way they put their models together that we can use or vice-versa. So, we first have to sit down, and take a look, and compare our differences and take it from there.

But these are relatively small sectors. I think some adjustments can be made for the

revised forecast, if necessary.

So, I'll ask PG&E, now, did you want to make any comments?

(Off-mic comment)

MR. KAVALEC: I'm sorry?

MR. WRAY: I'll follow up with written comments.

MR. KAVALEC: Okay, thank you.

COMMISSIONER SCOTT: Should we just repeat for the record that he asked the question, and PG&E answered that they'll follow up with written comments.

MR. KAVALEC: Okay, on to San Diego. The population growth a little bit lower than the State average, as well as per capita income growth a little bit lower.

Around 130,000 light-duty EVs on the road in 2028, according to our EV forecast. Of which around 80,000 are battery/electric vehicles, giving us EV consumption of 350 gigawatt hours by 2028.

PV installed capacity of 1,900 megawatts in 2028, in the mid case, and some load-modifying DR amounting to 27 megawatts in 2028.

In terms of consumption a major

difference between the two mid cases. Very close in terms of growth over the forecast period.

Now, as I mentioned before with Edison, this result here strikes me as a little strange and needs further investigation. This kind of big jump from 2016 to 2017, which pushes the new mid above the old mid, as you see. Otherwise, similar growth rates between the two mid cases throughout the forecast period. But again, this looks like something going on maybe with our peak model that needs to be looked into further.

Moving from consumption to sales, giving a relatively flat curve for sales. 4,400 gigawatts of total self-generation, about three-quarters of which comes from PV.

Then taking our purple curve, adding in losses to give us gross generation, then subtracting off our self-generation, 1,000 megawatts worth, gives us our net peak curve. Again, relatively flat for most of the forecast period.

The same order for our three major sectors, residential, followed by commercial and industrial. Commercial growth relatively strong, and as well as residential. So that San Diego's

consumption growth slightly faster than the State average.

And this jump that we talked about results in peak growing faster than consumption in 2016, in the mid case. But again, as I said, that jump needs to be investigated.

Comparing our forecast with San Diego's, San Diego has a higher EV forecast, which is actually, if I remember based on our 2016 forecast for EVs, so San Diego is haunting us with our own higher forecast from last year.

But aside from EVs and PV, our sales forecasts are very similar. And once again, San Diego has incorporated the peak shift so we can't directly compare peak forecasts at this point.

So, I'll ask San Diego for comments, and I believe they have a presentation where they want to show us the impacts of their peak shift on their peak forecast.

MR. VONDER: Hello. I'm Tim Vonder, SDG&E. I'm in the forecasting staff. I don't have anything prepared to present. And like Chris just said, the differences that we also noticed between the two forecasts are in the area of EVs and PVs. Other than that, we're pretty

similar.

With regard to EVs, we haven't had a chance, yet, to really dig into both the Energy Commission's forecast versus ours in detail to really comment on a lot of the reasons for differences.

But I can make two general observations about the two. And that is, one, we have more vehicles in our forecast than they do, which we're aware of. By the time we get to 2028, it's about a two-to-one ratio.

And I have to admit that updated our EV car count up through 2016 with actuals, and then we borrowed the growth rates from IEPR 2016 and applied those to develop our car forecast for the future.

We'd like to do a better job working with the clean energy people in our own company to try to get a better understanding of the market and where it's going. And we are very much looking forward to a DAWG working group. I think we can come and contribute a little, but I think we can go and really learn a lot. So, we're looking forward to that very much.

I guess one other little thing I'd like

to mention about the data that I was able to analyze, and that is on the use-per-car, and I can't comment on the type of cars in there, and the size of cars, but just the consumption on a per-car-basis for CEC versus SDG&E, we're slightly, like about 10 percent higher on the annual usage for charging than CEC. So, it's not much. The major difference between the two is certainly the number of cars in the forecast.

So, Ken is going to -- Ken Schiermeyer is Forecasting Manager, and he's done a rather interesting analysis on peak shift and hourly load, and he's going to make a presentation on that. And I think you're going to find a new graph in there that you've probably never seen before. I haven't. And every time I look at it, now, I have more questions. So, it's going to be interesting.

CHAIR WEISENMILLER: Yeah, I was just going to follow up on the one observation, which is as we work through the ZEV forecast, an issue certainly is going to be then the allocation among the utilities. So, certainly looking forward to your participation in the working group and thinking about, you know, San Diego --

along with what's the total number of what's your share versus Edison, versus, you know, et cetera.

MR. VONDER: Right.

CHAIR WEISENMILLER: Thanks.

MR. VONDER: That will be interesting. Yeah, we're looking forward to it. Thanks.

COMMISSIONER MCALLISTER: Thank you, Tim.

MR. SCHIERMEYER: You know, again, this is Ken Schiermeyer from San Diego Gas & Electric. And there seems to be a difference between the CEC and IOUs, so with regard to peak shifting in the peak forecast, for us particularly.

So, I thought I would just kind of give you an idea of what we're doing, in hopes of sharing information and maybe bettering the process.

You know, it's probably no secret that there's been a number of recent trends that are impacting system load shapes. You know, the two that come to mind easily are rooftop solar, of which at the end of 2016 we had 700 megawatts of installed capacity. And up and coming are electric vehicles, of which we had about 22,000 by the end of 2016.

And so, our challenge is with these

shifting load shapes the challenge is incorporating those shifts in our peak forecast. And so, as a solution we've revised our peak forecast framework to try to incorporate some of these shifts, and to also try to develop a framework that might be able to handle new technologies, you know, coming down the road. For example, battery storage or TOU pricing.

So, here's an example of our recent peak shift day. Just adding the solar back to the system load shape, you know, shifting the peak to later in the day by two hours.

In digging a little deeper, I think going forward I think we're going to need to dig a little deeper and see what's going on underneath the load shape. So, the blue bars are the system load shape. And I've included a red and green, you know, by sector, for commercial and industrial for red, and green for residential, and the kind of goldish yellow is the solar generation.

And I think we're going to have to keep an eye on, you know, what's going on beneath the system load shape when we analyze what's happening with the system peak.

To give you some perspective about what we did, historically we had a single-equation model to estimate system peaks. And system peaks, you know, were considered to be bend-up in one time frame, you know, the 2:00 to 5:00 afternoon time period, in the August-September, you know, time of year.

And so, we considered -- we didn't consider which hour it occurred into, you know, really, because they were similar enough that it worked for this methodology, prior to the growth in these new technologies.

That model included assumptions for system peak weather, to create a one-in-two scenario. It incorporated overall energy sales trends and calendar information. It did take into account PV, other non-PV self-serve load, EV charging, demand response. We essentially added them back to the peak. Forecasted that, and then subtracted off what we thought the forecast for those technologies was.

The problem was we had to pick an hour, you know, for what we expected these technologies to occur. So, if we picked a 3:00 peak, we had to have the solar, the installed solar capacity

with the amount of generation that happened at that time of the day. And so, that became increasingly problematic.

Our revised framework, we moved to more of an hourly peak model framework, and it matches hourly loads with the PV generation, the self-serve generation, the EV charging, the demand response that happened in that hour.

It's similar to the single equation except for we have one equation for each hour at this point.

So, you can think of it as instead of forecasting one peak for a 2:00 to 5:00 timeframe, we're essentially forecasting an hourly peak for each hour in the peak day.

This allows the system peak to float on the hour, by the hour, depending on the technology that is impacting that peak. And, you know, these are the technologies we're including today.

So, if you have something, a new technology that's going to happen in the future, if you have a load shape associated with it, you potentially could incorporate in this framework.

COMMISSIONER MCALLISTER: So, an example

would be helpful, sort of a concrete example to kind of understand what this means.

MR. SCHIERMEYER: Okay.

COMMISSIONER MCALLISTER: But I mean, I think I more or less get it. But I guess I'm wondering, say, in energy efficiency, can an hourly model -- you know, will this help you understand the benefits of -- you know, the relative benefits of different energy efficiency technology, sort of depending on when you're going to be used throughout the day, is that what you're saying?

MR. SCHIERMEYER: Exactly. Yeah, so and that is part of some of the challenges, you know.

COMMISSIONER MCALLISTER: HVAC versus lighting, versus water heating?

MR. SCHIERMEYER: Yeah, getting really good end-use information at an interval level. You know, we have an upcoming load shape project that really could benefit this, I think.

COMMISSIONER MCALLISTER: Yeah, because I mean I'd like to know more sort of offline. You know, not on this forecasting topic, actually, but just on it generally. It would be interesting to compare notes on those

methodologies for how to do that.

MR. SCHIERMEYER: Okay.

COMMISSIONER MCALLISTER: Because I think this is an important issue for planning across the board, not just for the forecast.

MR. SCHIERMEYER: I think so, too. I think, you know, you could -- you know, in light of everything that's happened, if you're evaluating a new thing you could, say, depending on the hour, you know, how valuable or how impactful is it going to be.

COMMISSIONER MCALLISTER: Yeah, how is it going to impact the ramp, you know, possibly.

MR. SCHIERMEYER: Exactly.

COMMISSIONER MCALLISTER: Right, I think that's essentially what we're talking about.

MR. SCHIERMEYER: Yeah, yeah.

COMMISSIONER MCALLISTER: Okay, thanks.

MR. SCHIERMEYER: This graph, this is what Tim was alluding to. This is -- I tried to develop and I only did it for 3:00, 4:00, 5:00, 6:00 and 7:00. The load that happened on the peak day by year.

And I think what it's showing is, you know, in forecasting a lot of the times you

depend on the past to forecast the future. But I think what this is showing is the past might be different than the future. And so, switching to an hourly framework I think will allow you to handle this better.

But, you know, just at a high level -- it's hard to see, I'm sorry about this. But there's a black line with markers on it, and that's the system peak for the year. And, you know, starting with 3:00, which is the red, it really -- that's when our system peak used to happen. And so, that red line was matching the dark black line pretty closely until the peak shifted to -- oh, I'm sorry, until we started to see more and more installed solar, you know.

You know, as more solar was happening, you know, the capacity factor's 68 percent. And so, as you installed more and more, it knocks it down even more.

Conversely, our peak last year was 6:00 and it was the latest system peak we've had so far. And that's the blue line there. And in the past it was lower than the system peak until the peak got moved in later in the day due to increasing amounts of solar. And that's now our

forecasted system peak time.

And even more interesting is you see a yellow, kind of gold line, and that's 7:00 p.m. And, you know, it starts off as the lowest but, you know, by the end of the forecast it's closing the gap.

And so to me, that tells me that even if you increase the amount of solar, the capacity factor's only 5 percent at that time. And if you think about in terms of the load shape you're getting into the residential sector, you know, heavily weighted towards the residential sector. And so that's where you see residential growth and it's continuing to grow.

So, you know, this is what we've done for this forecast. It's new. And we hope to continue to try to improve it in terms of what kind of data we can use, any information we can gain from load shapes, or energy savings by load shape.

COMMISSIONER MCALLISTER: So, this takes a little while to get your head around. But are you anticipating that the peak not only move later, but also sort of flatten out and last longer? Like, you know, if it moves into the

evening times is it going to last until 8:00 p.m. or something, because that's kind of what this looks like it might be showing.

MR. SCHIERMEYER: Well, yeah, I don't have an 8:00 p.m. line on here. I tried to keep it simple.

COMMISSIONER MCALLISTER: Are these at the hour or are these a summary of the hour?

MR. SCHIERMEYER: Yeah, these are at the hour.

COMMISSIONER MCALLISTER: At the hour.

MR. SCHIERMEYER: Yeah. And so, the black line, it's covered with the blue, but that's our system peak forecast. So, we're expecting it to grow.

COMMISSIONER MCALLISTER: Yeah, it looks like in 2028 you've got a flat -- I mean, you've got a similarly high load at 6:00 and at 7:00.

MR. SCHIERMEYER: Yeah.

COMMISSIONER MCALLISTER: So, I mean, that's not a very peak -- I mean, that seems, you know, to be broadening as well.

MR. SCHIERMEYER: True, yeah. And we found that, yeah, the loads were similar. So, you could switch from one hour to the next

easier. But I think they're growing. I think when you're reaching out to that time frame, they're flattening out but they're growing at the same magnitude.

COMMISSIONER MCALLISTER: Okay, thanks.

MR. SCHIERMEYER: Okay.

COMMISSIONER MCALLISTER: Thanks a lot.

MR. SCHIERMEYER: Okay, thank you.

MR. KAVALEC: Thanks Ken.

Okay, our final victim of the day is SMUD. And we have the highest population growth in SMUD, of any of the planning areas, at least according to DOF. Per capita income growth a little bit lower than the State average. About 40,000 EVs on the road in 2028. Over half of which are battery/electric vehicles. And around 150 gigawatt hours of EV consumption in 2028.

Installed capacity of behind-the-meter PV, a little over 600 megawatts in 2028, in the mid case.

And so, comparing the mid case, a little bit higher growth because of the higher population growth in SMUD, comparing the two mid cases.

And because the residential sector is

growing faster than we had in 2016 as a relative share, we have a higher growth in our peak demand forecast for SMUD, or for peak end-use load.

Moving from consumption to sales, subtracting off around 1,000 gigawatt hours of self-generation, almost all of which is PV, we're left with, as we saw in the case of LADWP, we still have an upwards sloping sales curve for most of the forecast period. Average annual growth of almost one percent.

And moving from the peak end-use load, adding in losses, and then subtracting off self-generation we end up with our net peak, the dark blue. Again, upward sloping, unlike what we saw for the IOUs.

Very strong commercial growth in the case of SMUD, from the higher population projections. And one of the higher forecasts for industrial growth, which is much flatter for the other planning areas.

Because of this strong growth, SMUD consumption grows the fastest and grows faster than the State average for 2016 to 2028. And because we have comparable use of relatively small impact from PV, our net peak demand grows

almost as quickly as consumption, which is not true in the case of the IOUs.

Comparing our forecasts with SMUDs, SMUD has higher EV and lower PV forecasts, although we're not substantially different.

Aside from EVs and PV, and accounting for committed savings, which are in the SMUD forecast, but not in our forecast, SMUD's sales and peak forecasts are lower. And one important reason for that is SMUD is assuming slower population growth. They're using Global Insight, I believe, and not DOF, which gives you a lower population growth projections, reducing their sales and their peak forecasts.

And Nate Toyama at SMUD has some insights on what may be a changing relationship between sales and peak, which would imply that we may be overstating peak because of that.

So, at this point, Nate, I'll ask you to come up and make comments, and then you have a short presentation for us.

MR. TOYAMA: Thank you. Nate Toyama from SMUD.

(Pause)

MR. TOYAMA: Let me give you some

background of what I want to talk about, first. I met with the CEC staff Friday, and we were going over the forecast and comparing our forecasts. And Chris brought out this spread sheet that had maybe 20, 30 columns, and he was adding things and subtracting things, and we're trying to compare our forecasts and see where we ended up.

And when we did that, after that exercise, I went home and looked at the spread sheet again and I had forgotten what Chris had told me to do.

But it is very complicated in the sense that what we're trying to do is compare forecasts and see where we line up. And by looking at the forecast, we have different numbers for PV, EV. We include in our forecast energy efficiency, which would be unbudgeted in your terms, which we include in our forecast.

But, you know, on one thing the forecasts were very different of these incremental changes in the way that we use energy. And whether we're ever going to reconcile these differences or agree to have the same forecast, or maybe agree to disagree on these forecasts, we're probably

never going to have similar or identical forecasts for these incremental changes. And that's simply because we use different models, we have different assumptions, we have different time periods we're looking at, and we have our own staff that does this.

So, you know, it was interesting to look at the end results of these forecasts because we need a baseline forecast. We need a baseline forecast for predicting sales and for loads.

But even if we had the same incremental changes in our load we would still have differences in our forecasts.

And so, that sort of made me realize that the incremental changes that we have, which are important to understand, don't necessarily drive the forecast. What drives the forecast is what I call the base forecast, or in the data we submitted. I refer to it as our unmanaged forecast. And it's really the underlying structure of our forecast. And that's really what I want to take a look at.

And so, for today's presentation what I'm doing is I'm taking and developing a base forecast which looks at the end result, the

baseline forecast, and I start to strip away the incremental changes that we have, like energy efficiency, PV, EV for SMUD. And for the CEC forecast I take out PV and EV.

I compared the base forecasts and I wanted to develop some sort of forecast metric. And in this case the forecast metric is use per account. And here I have the base sales forecast.

And so here I show how I derive what I refer to as the base forecast, which is this column over there, slightly in the middle.

But still, the metric I'm using customer accounts. I could have used population, which we both have. I couldn't find a customer account from the CEC forecast, so I used SMUD's forecast for both cases.

The metric I'm using is sales per account and it's the final column on the right-hand side, which is in megawatt hours. And that's what I want to compare because this is what's driving the overall forecast.

The next sheet is a chart which shows the differences in these forecasts. And the red line is the CEC, what I call a base forecast, which is

increasing over time for use per customer.

And in SMUD's case, it's decreasing over time. And so, I think this is sort of the fundamental differences that we have is that even if we had exactly the same amount of the EV and PV, the forecasts will still be different. And it's really driven by basic assumptions and that's what's embodied in our forecasting models.

And now, I could explain what's going on with SMUD. With SMUD's forecasts, what we have basically are new houses we know are more efficient. We have some adjustments or the saturation and the changes of efficiencies of ACs. So, these are all driving the sales forecast lower. Now, we don't have any sort of income assist, or other sort of bucket of goods for people to be purchasing in the future because, exactly we don't know what they are, anyway.

And whether or not an income assist you might pick that up correctly we don't know or I'm hesitant about putting something that we don't know about. And so, we don't include them in our forecast.

I mean, basically, here is new

construction, efficiency standards, and saturations or changes in saturations to come up with our forecast and that's why it's declining.

The same thing with peak. The same process we go through. We have the basic forecast, or the baseline forecast for both, for SMUD and for the CEC. We strip away some of these things. We have then our base EE, a base forecast of peak which, again, is in the middle.

And then, finally, our metric which would be peak per account.

And then we have the same result. SMUD's peak forecast is declining because of the changes in efficiency, the newer houses being much more efficient. Just basically looking at our (indiscernible) there shows us that new homes basically use about 20 percent less than our average homes.

And then, for the base of our residential customers we have an end-use model that captures changes in efficiency over time, and how the equipment changes over time. So, these all lead in a decline in our peak for account.

That small little decline, beginning in 2019, is our TOU program, for residential time of

use, to default case. So, we see a slight decline. Systemwide, there's about 70 megawatts.

And then, when we look at the CEC's forecast, again it shows the same characteristics as the sales forecast, where it's increasing over time. It was really the peak forecast that Chris and I talked about, that when we actually used the same assumptions, the differences between the peak and the sales forecasts were still about 200 megawatts by 2028.

And so, I think we can go back to the base forecast and say that it's how we estimate these models that are making a large difference in the way that SMUD forecasts its sales and peak versus the way that the CEC forecasts its sales and peak.

And so, that's the conclusion I have is our forecasting models are very different. And regardless of what we saw about EV, PV, and if we were to include SMUD's unbudgeted EE, it's definitely very different.

Now, but in the case of sales, actually when we include everything, they are very similar. And I would say that they're very similar more on coincidence than by planning or

by how exactly we forecast these things.

That's the end of the presentation. Questions?

COMMISSIONER MCALLISTER: I mean, I guess I'd like to get the flip side of that from Chris. You know, my understanding is that one of these is kind of a -- your forecast is kind of a managed forecast, kind of all in and ours isn't?

MR. TOYAMA: For our baseline it is.

COMMISSIONER MCALLISTER: Yeah, okay. And we're not quite at that point, yet, because we haven't done all the wedges to add up to get the long-term managed forecast, right. So, you'd kind of expect --

MR. TOYAMA: Well, if you looked at our forecasts, our forecasts are relatively flat over time, when we included everything, our managed forecast.

The same thing with both peak and with sales, they're both relatively flat.

Where the CEC has continual, you know, increasing over time, even if we include these things.

COMMISSIONER MCALLISTER: Okay.

MR. TOYAMA: But you're right, our

baseline forecasts would be including everything that we do as programs at SMUD.

COMMISSIONER MCALLISTER: Okay. And then all the stuff that gets layer on, on our side, makes it diverge from where you're at, is that it?

MR. TOYAMA: Yeah.

COMMISSIONER MCALLISTER: Okay.

MR. TOYAMA: I think it goes back to the basic forecast and that's why it diverges. Because actually when we sum up our programs, even though the individual programs are different, when we sum them up they get pretty close altogether.

COMMISSIONER MCALLISTER: Okay, thanks.

MR. TOYAMA: Thank you.

MR. KAVALEC: I'll just mention that at a fundamental level the difference we have is from incorporating income growth, which I don't believe you incorporate directly into your model. Right. So, when you have rising per capita income, or rising per capita GDP, you're going to have more commercial and residential growth, all else equal.

So, I think that what is driving that

wedge is that much of that wedge is the impact that income has on our forecast.

COMMISSIONER MCALLISTER: That issue right there seems like one that, you know, maybe not within the forecast practice, but all eyes are kind of thinking, now, of really looking at this issue of decoupling economic growth from resource consumption.

And I think it would be, you now, as we gather more data resources, more analytical capacity that seems like something we could be working at more, in more depth to really track what's happening out there in the economy with respect to our levelized planning --

MR. KAVALEC: I think that you provide some valuable insights with what you did in the comparison that you did.

CHAIR WEISENMILLER: Chris, I just have one of the more inappropriate timing questions, at least in terms of Edison just headed for the door. But at least in history we've had these issues of normalization in data between us and Edison. And I'd like to think that's been all resolved?

MR. KAVALEC: I like to think so, too.

(Laughter)

CHAIR WEISENMILLER: Yeah, I was going to say we probably should -- anyway, if you get a chance, if you could just circle back with that just to make sure that neither of those pop up, you know, at the last minute again.

MR. KAVALEC: Right. And the last -- was it last year, or the year before, we set up a structured process that we had the IOUs buy in to and, you know, we're going to do such and such by this amount of time, and this leaves time for review and comments. And that seemed to work okay. We didn't have it pop up at the last minute again. So, that's what we're going to try and do again this time is set -- put a time limit on it, structure it, and hopefully get it over with in time for the releasing the forecast.

CHAIR WEISENMILLER: You know, I think the other just sort of just summary thing is to say thanks for the split discussion. I think it sort of emphasizes generally the ZEV and PV. Although, I'd like to sort of just ask the proverbial question of among the various forecasts where -- you know, ignoring those factors, is there anything else for any

individual utility that really reaches the top of your list?

MR. KAVALEC: I mean, in terms of differences?

CHAIR WEISENMILLER: Yeah.

MR. KAVALEC: The differences -- well, I mentioned some for PG&E, a couple of the model specifications.

CHAIR WEISENMILLER: Yeah, I was trying to get more in terms of, of the various utilities, which one do you have the most difference from, ignoring ZEV and PV?

MR. KAVALEC: The most differences we had were with PGE& on the sales side and with SMUD on the sales side.

CHAIR WEISENMILLER: Okay.

MR. KAVALEC: Which was discussed.

CHAIR WEISENMILLER: Thanks.

MR. KAVALEC: And the peak is a whole different ball of wax that we didn't get a chance to compare today, but we will for the revised forecast.

Because I think peak differences tend to be sharper than sales differences.

CHAIR WEISENMILLER: Thanks. Thanks.

MS. RAITT: So, I think that's it for presentations. We could move on to public comment.

CHAIR WEISENMILLER: So, do we have anyone in the room who has public comments?

MS. RAITT: Anyone on WebEx who has comments, go ahead and raise your hand for the coordinator.

CHAIR WEISENMILLER: And if you do have comments or questions, it may help to e-mail those in, or chat, anyway. Do we have anyone, that's the first question?

MS. RAITT: It doesn't look like it.

CHAIR WEISENMILLER: Okay.

MS. RAITT: But we probably should open up the lines, if we have some phone lines.

CHAIR WEISENMILLER: Yeah.

MS. RAITT: So, if anyone's on the phone line and wanted to comment, we'll have your opportunity here. And if you're on the phone line and didn't want to comment, please mute your phone.

So, the phone lines are open if you wanted to comment.

No, okay, I think we're not having any

comments.

CHAIR WEISENMILLER: Okay. So, remind people when comments are due?

MS. RAITT: Comments are due August 24th and this gives you all the information for submitting comments.

COMMISSIONER MCALLISTER: So, you can probably close the phone lines.

MS. RAITT: So, I think that's all I have.

COMMISSIONER MCALLISTER: All right. So, this has been a really good day. And, actually, the conversation's been quite efficient in highlighting the pending issues and sort of highlighting what's going to happen in the next steps, and sort of rounding it all out going forward. And so, I'm happy with how things are going and I don't have any more comments.

CHAIR WEISENMILLER: No, certainly want to thank Chris and staff for organizing things today. I think there's a pretty clear roadmap for us, of the issues, a pretty good presentation. And again, I realize this is preliminary. You know, God knows, as she's talking under the hood other stuff can come up.

And, you know, traditionally on these things and also for the utilities obviously our presumption was this was kicking off and we'd get much more detailed comments in our written comments. And in, you know, working through the various processes, all processes to identify differences and work through those.

But again, I think it was a pretty productive meeting. I think in terms of, you know, obviously, as you said the ZEV and the PV are the big issues. And those are ones which, by definition, there's a lot of uncertainty. We're pretty early in the progression. You know, it's certainly something that, you know, presumably ten years from now it's going to be a lot easier to do those forecasts of both of those, and probably pretty routine. But at least at this stage we're still struggling to come up with the data, the methodologies and, again, trying to figure out what's the key things that really impact that.

So, certainly encourage focus on that and encourage participation by the utilities and all the stakeholders into those issues, so we can get the best numbers we can.

Then, you know, to the extent you guys can think a little bit about how to reflect some of the uncertainty in those. Although, again, realizing in our forecast we have lots and lots of assumptions. And, typically, it's sort of a central limit thing where you could be low on one and higher on the other, and things are somewhat offsetting.

And it's sort of where you have these two, which are growing pretty fast, that a lot of attention comes in. So, anyway, thanks again.

COMMISSIONER SCOTT: Thank you.

CHAIR WEISENMILLER: When is it the comments are due? Let's make sure we get it on the record.

MS. RAITT: Yes, August 4th -- excuse me, the 24th.

CHAIR WEISENMILLER: Okay, August 24th, we're looking forward to those documents coming in. Thanks again. This meeting is adjourned.

(Thereupon, the Workshop was adjourned at 3:29 p.m.)

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REPORTER'S CERTIFICATE

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

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

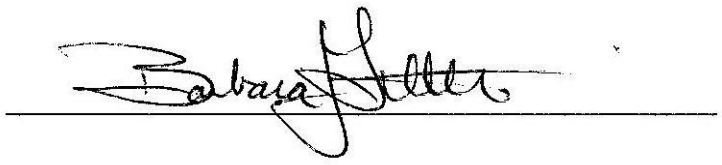
IN WITNESS WHEREOF, I have hereunto set my hand this 25th day of August, 2017.

TRANSCRIBER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were transcribed by me, a certified transcriber.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 25th day of August, 2017.



Barbara Little
Certified Transcriber
AAERT No. CET**D-520