DOCKETED	
Docket Number:	19-IEPR-03
Project Title:	Electricity and Natural Gas Demand Forecast
TN #:	231545
Document Title:	Transcript of 12-2-2019 Workshop Re 2019 Revised Natural Electricity and Natural Gas Demand Forecast
Description:	N/A
Filer:	Cody Goldthrite
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	1/16/2020 8:53:43 AM
Docketed Date:	1/16/2020

CALIFORNIA ENERGY COMMISSION

COMMISSIONER WORKSHOP

In the Matter of:	)	Docket No. 19-IEPR-03
	)	
2019 Revised Electricity and Gas Demand Forecast	)	RE: 2019 Revised Natural Electricity and Natural Gas Demand Forecast

CALIFORNIA ENERGY COMMISSION (CEC)

WARREN-ALQUIST STATE ENERGY BUILDING

ART ROSENFELD HEARING ROOM, FIRST FLOOR

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, DECEMBER 2, 2019

10:00 A.M.

Reported by:

Peter Petty

APPEARANCES

COMMISSIONERS PRESENT:

Janea S. Scott, Vice Chair

Andrew McAllister, Commissioner

Karen Douglas, Commissioner

Patty Monahan, Commissioner

Ken Rider, Advisor to Chair Hochschild

CEC STAFF PRESENT:

Matt Coldwell

Ingrid Neumann

Cary Garcia

Mark Palmere

Bob McBride

Elena Giyenko

Aniss Bahrenian

Sudhakar Konala

Nick Fugate

Mike Jaske

Rosemary Avalos, Public Advisor's Office

PUBLIC COMMENT

V. John White

Ken Schiermeyer, SDG&E

Delphine Hou, CAISO

INDEX

P R O C E E D I N G S

10:06 A.M.

SACRAMENTO, CALIFORNIA, MONDAY, DECEMBER 2, 2019

MR. COLDWELL: All right. Good morning, everybody. Welcome back from Thanksgiving holiday, hopefully everybody had a good one.

So my name is Matt Coldwell, I'm the manager of the Demand Analysis Office here at the Energy Commission. I'm filling in for Heather this morning who usually leads these IEPR meetings. So I'll try my best to do a good job in her stead.

So just quickly I'm going to go over just a few housekeeping items to start with. So the restrooms are just right outside the doors here to the left in the atrium. If there's an emergency and we need to evacuate the building, just please follow staff out to Roosevelt Park which is located diagonally across the street from the building here.

Just want to mention today's workshop is being broadcast through our WebEx conferencing system. And parties should be aware that you are being recorded, if you get up and make comments. So we'll post the audio recording and the written transcript on the Energy Commission's website in about a month.

At the end of the workshop there will be an opportunity for public comments and so we're going to ask parties to limit those comments to about three minutes. For those of you in the room that like to make comments, you can fill out a blue card and give it to me or give it to the Public Advisor Rosemary there in the back, and then when it's your turn to speak, just come up to the center podium here, the microphone, and give -- it's also helpful to introduce yourself so the court reporter has your name.

For WebEx participants, you can use the raise your hand feature that WebEx provides if you want to make a comment, and we will call on you during the public comment period. You can also use that same feature to lower your hands in case you want to withdraw your comment.

Materials for this meeting are available on the website. Hard copies are on the table at the entrance to this hearing room. Written comments on today's topics are due on Monday, December 16th by 5 p.m. The workshop notice explains the process for submitting those written comments. And of course you can ask staff, too, if you have any specific questions.

So finally, I'd like to thank our participants for being here today, and then just request that you identify yourselves before speaking. This is help --

this is helpful for those of us in the room, for folks participating remotely, and of course for our court reporter.

So we're here today to talk about the 2019 Electricity and Natural Gas Demand Forecast. We'll also have a presentation on our Transportation Energy Demand Forecast this morning too. But I'll -- with that, I'll turn it over to the commissioners for opening remarks.

VICE CHAIR SCOTT: Great. Good morning, and welcome everybody. Thank you so much for joining us today at our IEPR Commissioner Workshop on the 2019 Revised Electricity and Natural Gas Demand Forecast. I am Janea Scott, the vice chair of the Energy Commission and overseeing the IEPR process this year. We want to welcome everybody.

I do want to reiterate what Matt said this morning. If you'd like to make a public comment, please grab a blue card and you can hand it to him or to our public advisor who's waiving one there for you to see. And we will be delighted to hear from you.

I'm looking forward to hearing the information on our revised forecast here. As you all know, the forecast work that -- and analysis that the Commission staff does is foundational to all kinds of clean energy planning that the state is overseeing. And it's something that both our sister agency, the Public Utilities Commission and also the California Independent System Operator use in their planning processes as well. So it's fantastic to really hear what's going on here, where some of the kinks may have been, what we've worked out, and really get those numbers well done for all of us.

I'm also very much looking forward to the transportation forecast, it's something that we have been working very hard to update and make sure that we've got the latest and greatest information with electric vehicles, fuel cell vehicles, and making sure that as we make this transition to zero emission vehicles, we're capturing that appropriately both within the transportation forecast but also as it begins to reflect in the electricity forecast.

So looking forward to today. Let me see if any of my fellow commissioners have remarks that they would like to make this morning.

COMMISSIONER MCALLISTER: Great. Thanks, Vice Chair Scott.

I'm Andrew McAllister, lead on efficiency and overseeing the forecast works. So really excited to see the series of presentations. Want to thank Nick, Cary, and the whole crew for -- Siva, the whole team which I know it's -- it's small but mighty. And also looking forward to the transportation forecast update.

Also, the storage and the self-generation update. I think, you know, the sort of long-term scenario building for particular storage. But both of those continues to be really important as we try to figure out sort of what the distribution level forecast, what changes and distribution level resources actually implies for the overall forecast.

And then also the hourly, the evolution of our forecast to produce hourly results is also really critically important for long-term planning. And certainly with our sister agencies, that’s a key resource for transition planning and for the RA work, and just really, really critical in terms of, you know, as we move towards understanding load shapes and just the impact on our overall resource mix on a time sensitive basis. The work that we’re doing and the analytics we’re doing are really evolving us in a direction that’s going to -- that’s super necessary but also really interesting. So building those capacities is something that’s critical for the Commission going forward.

So I really appreciate all the team’s work both up to now, today, and to come. So looking forward to hearing what everyone has to say today and getting some feedback.

VICE CHAIR SCOTT: All right. Back to you.
MR. COLDWELL: All right. Thank you, Commissioners.
So first up today is Cary Garcia who's going to be providing just kind of a general overview of the forecast. So I'll invite Cary to come on up.
Let me see if I can do this. This is the part where Heather is a lot better than me. So.
MR. GARCIA: All right. Good morning. So after Thanksgiving. I'm primarily running on caffeine now so less tricky. So hopefully I make sense up here.
So I'm Cary Garcia. As Matt mentioned, I'm the lead forecaster in our Demand Analysis Office. And so today I'm going to, as the title suggests, just an overview of our statewide process for doing the forecast. And then I'll a little bit later in this presentation I'll get into some specific details about the planning area forecasts.
Although I will for the IOU planning areas, I will not be getting into the peak demand because as Andrew mentioned, that's getting handled through our hourly demand model which Nicholas Fugate will be talking about later today.
But nonetheless, the consumption and sales forecast will be driving some of that information so

hopefully this provides some background to those forecasts later.

So first I just wanted to go over some of the basic products that we produce. As I mentioned, electricity consumption and sales forecasts, this particular forecast is forecasting from 2019 through 2030 using 2018 as our actual historical starting point. And we do these forecasts by eight planning areas in the state. PG&E, Edison, San Diego, the three primary IOU territories, and then we also do Los Angeles Department of Water Power territory, Burbank and Glendale, Imperial Irrigation District, and what we call NCNC, our Northern California Non-CAISO. And so that's going to include SMUD service territory along with Turlock, Modesto, Merced, and some other portions of the balancing authority of Northern California.

And so in addition to the consumption in cells forecast, we also produce peak forecasts. As I mentioned, we rely on our hourly electric load model for the IOU planning areas, and we use our traditional essentially a translation for peak end-use based on consumption data to peak using load factors from our older but still functional HELM model, hourly electric load model which was the predecessor to the hourly electric load model that we use now for those IOU planning areas.

And so these peak forecasted in by TAC as well as those balancing authority areas and we lay these out in our demand forecast forms, sets a baseline form for the high, mid, and demand scenarios as well as what we call our load serving entity and balancing area forms which breaks out LSE, sales, sales by individual LSEs, and also peak demand by particularly important areas for the ISO's planning purposes. And so that will be located in the form 1.5. So we're still wrapping those up, but those will be posted shortly following this workshop today.

And we also produce end-use natural gas forecasts. Same -- pretty similar, slightly different planning areas looking at PG&E, SoCalGas, and San Diego Gas and Electric being the primary three gas providers in the state. And those will also be getting wrapped up as well shortly this week. But I don't have slides prepared yet for those but they are a part of our typical full IEPR forecast.

We also include -- so these forms that I mentioned previously are we start off with our baseline forms and we also produce manage set of forecasts for both sales and peak demand. And this is going to include additional achievable energy efficiency that we've developed this past year using the 2019 potential and goal study for IOUs as well as POU potential savings from municipal utility reports.

And typically we'll -- planning in the state revolves around the Mid-Mid which is sort of our, you know, our baseline best estimate of what the demand is going to be along with energy savings. And our more conservative case, which is our Mid-Low, essentially the same mid demand case but with slightly low expected savings in the future.

And please stop me if you have any questions along the way. I saw -- I know there's a few new -- fresh faces that I don't typically see at our Demand Forecast Workshops.

So a little bit about the method as I've laid out some of the products. The models start off with our end-use models by sector so residential sector, commercial, industrial, mining, resource extraction, transportation, communication, utilities, Ag, as well as street lighting. So we -- those models depending on historical electricity demand in the state along with rate forecast for electricity and natural gas. We also have a self-generation model that we spoke about earlier that now includes storage forecasts which Sudhakar will talk about later today. As well as transportation electrification with the help from our transportation electrification forecasting unit.

And then as I mentioned, this information gets fed into our hourly forecasting model for those IOU territories which essentially drives the trend for peak demand which you'll see later.

We also apply some adjustments accounting for additional committance efficiency savings. So that's savings that is going to be from new programs that will be implemented in the 2018, 2019 period that we didn't capture in previous forecasts. And that will essentially drive down -- add savings to our forecast driving down some of the starting points and lowering some of those forecast trends. As well as the additional achievable energy efficiency which I'll talk about a little bit more. And then we also include some adjustments for climate change as well.

So just to lay out our demand scenarios or demand cases. The key element here is really demand that's the -- oh. So we're starting off with our high demand scenario and that essentially pretty simply just has high economic and demographic projections along with higher climate change impacts and higher penetration of electric vehicles. But to create that, a true higher demand case, we've laid it out to where you would expect with high electricity demand, you would have lower rates and therefore less incentive for self-generation. So you'll notice when I talk about rates or Sudhakar will talk about PV, there's a flip-flop in demand scenarios which sometimes can be confusing for folks.

The low demand case is the opposite of that. So essentially a low economic demographic information in electric vehicles, penetration higher electricity rates and more self-generation but no climate change impacts. The baseline assumptions lie between both the high and the low with moderate amount of climate change which I'll talk about more.

The key inputs that we rely upon are primarily Moody's Analytics and Department of Finance. Department of Finance is used for population and household estimates for a high, mid, and low cases. And Moody's really just the economic information. Gross state product, employment. I mention employment twice because there are different types of employment by sector that are useful in some of our models. Actually, I mentioned that twice because that's a typo but I was trying to save myself there.

And just below what I have here are some of the assumptions that drive the mid case. And throughout this presentation I'll primarily focus on the mid case so if you see something that doesn't say like high or mid, I'm generally focusing on the mid case because that’s what we’ll use for our planning purposes as I mentioned before.

But we’re seeing in those -- some of the drivers of the economic information that we receive. Unemployment rate in some cases does start increasing so we’ve typically seen, you know, more and more employment. But in the latest projections that we have in comparison to 2018, there was a sort of a dip in 2021, 2022, and in some planning areas, that dip has been more dramatic right around that time period.

We see slower wage growth as well. And these are just -- the following three bullets are really just what some of the drivers here are. So some uncertainty around trade that’s occurring in those projections. There will be some rebound so you’ll see this trend where things start dipping down a little bit and then slightly slower growth in the long term.

And then with the latest Department of Finance information, we do see some increases in households and some planning areas. Statewide it’s a very small increase, but population growth remains pretty slow and if not a little slower than we previously -- the previous estimates we received from the Department of Finance.

Some other inputs that we have in our forecast.

As I mentioned, PV energy that Sudhakar provides through his modeling efforts. I won't steal his thunder but these are some quick bullets here and he'll get into more detail in that later today. Light-duty electric vehicle consumption that we've included in the forecast. So it's roughly 15,000 gigawatt hours of consumption by 2030, most of it being attributed to residential electric vehicle charging.

We also have medium and heavy-duty vehicles in our forecast that the TEFU unit provides. You can see pretty significant growth in that sector, so that's going to be buses, transit buses, and various, you know, gross vehicular weight classifications for the different types of medium and heavy-duty vehicles.

And they also include off-road electrification which is going to be things like forklifts and other sort of -- what else? I think forklifts is the one that comes easiest to my mind. I'm actually not quite -- I'd have to ask our transportation (indiscernible) the different things that can be electrified that don't go on the road. But those have been updated for this forecast as well. And so that will affect sectors like commercial, our TCU forecast which includes like port electrification and military bases and things like that.

As I mentioned, climate change is included in this forecast. There are high and mid demand cases. And these scenarios were developed by the Scripps Institute of Oceanography. But we -- essentially using the same scenarios that we've had before, I think there's an update on the horizon in the 2021, 2022 range, so we revamped this. But essentially what we're doing is keeping those same projections and just -- what would you call it -- incrementing it to the new starting point to keep -- to keep it in line with what our projections are now for current demand.

The last bit here, Ag and water pumping has been adjusted. So we may have -- we may have mentioned in our preliminary forecast that we've now developed a cannabis cultivation forecast. And I'll -- we're going to talk about that in a little more detail. Unfortunately the staff that developed that wasn't able to make it but I'll do my best to answer any questions in that forecast and provide detail around that.

But ultimately, it's roughly around almost 4 percent of total consumption by 2030 so getting to around 12,000 gigawatt hours. So essentially, it grows that population. And I'll talk about that a little bit more. But this is primarily focused on indoor cultivation which is expected to be the bulk of the crop production in the state.

So getting into climate change a little bit. These are the updated projections or I guess re-incremented projections focusing on the 2019 starting point when they would have effect because we would expect that in the 2018 consumption history that we have, we would already be seeing the impacts of climate change in that data. So we're simply just re-estimating it to take into account the impacts that would occur in 2019 and out to 2030.

So the high demand case, what's happening there is that this is using a business as usual climate mitigation scenario from Scripps. So essentially there's no climate mitigation occurring and so you see an increase in temperatures due to the GHG emissions. So that's something around the range of 1½ to 2 degrees increases in temperatures over time. The mid case is more moderate assuming some level of mitigation but as we know, we may not be doing the best work that we can be doing on that so there's still a fair amount of increases in temperatures that occur.

And so this sort of shakes out into a net effects being that although you have increase in cooling degree days that would increase electricity demand, you also have an increase in heating degree days over the year which essentially would reduce space heating and things like that in the electricity sector. So ultimately it's sort of a net effect and we -- we go about developing these using, as I said, those temperature projections from Scripps. We estimate a set of econometric models focusing on the commercial and residential sectors which are going to be the most weather sensitive. And so from that, we develop essentially a coefficient for sensitivity to temperature changes and then we use that -- use those trends from the different high and demand, high and low -- sorry, high and mid temperature changes due to climate change to estimate what those impacts are. So basically a degree equals, you know, two degrees in temperature over this much time period will equal X, you know, X number of gigawatt hours based on that coefficient.

COMMISSIONER MCALLISTER: So Cary, just to -- so you've -- you've put that in energy terms, right, and I think the -- one of the most important issues here is how it effects peak and peak shift and seasonal --

MR. GARCIA: Yeah.

COMMISSIONER MCALLISTER: -- load shapes. And so just wanted to make sure that you're going to be talking about that as well.

MR. GARCIA: Yeah. So I typically would have included -- or in previous history, we would have included the peak numbers here as well. But now, which Nick will talk about later today, we've started modeling climate change on an hourly basis and that's something that Scripps has helped us develop.

So they've essentially taken the previous daily -- essentially it was daily temperature data that we've had, and they were able to create an hourly profile of those impacts for us out to 2030. And so those are going to be incorporated into the hourly forecast.

COMMISSIONER MCALLISTER: Okay.

MR. GARCIA: And will have effects on peak.

COMMISISONER MCALLISTER: Thanks.

MR. GARCIA: And looking at Nick, he will get into that. He has a thumbs up so confirmed there.

Yeah, I should also mention, you mentioned peak, but we also do the same thing for natural gas as well.

Okay. So efficiency. So here we're including in the revised forecast, we have the new 2018 to 2019 utility program savings from both the IOUs and the POUs in the state. And so this will also include standard savings. So the latest 2019 Title 24, Title 20 appliance standards as well as some federal standards that are baked into the forecast. So those will be the new committed pieces. And as I mentioned, the new potential and goal study provided us with new information for additional achievable energy efficiency that we apply to our manage forecast.

So looking at a committed savings, this might seem like a goofy slide but I'll kind of walk you through it. So starting with that orange line there, that's the new building and appliance standards. So as you have new construction and new appliance standards being applied to those buildings, you would see the savings start increasing over time as those compliance with the standards starts maximizing. So you can see there's a growth there over time.

That blue line, that's an efficiency program savings so that's a little different. So what essentially happens there is the programs come on line in 2018, 2019. And they begin to decay off as the useful life of those programs start declining over time. And so the way it shakes out, that green line at the top was essentially the combination of both those savings streams occurring. So you have this declining and new efficiency programs because there's no new committed savings occurring while the new building and appliance standards are taking effect.

So ultimately you have the high amount of savings occurring in 2019 and 2020 all the way through 2021 as well. And then this slowly starts declining as that efficiency programs decline. You can see from the graph efficiency programs, the latest ones, provide the bulk of that savings in the beginning. And then slowly around 2025, you can see they sort of level off there and end up matching the building standards, and the building standards end up keeping the total committed impact on the forecast from declining further.

But you can see that total impact in the beginning there is pretty large in the first part of the forecast, 24,000 gigawatt hours. And it inclines a little bit as you can see by 2030.

COMMISSIONER MCALLISTER: So Cary, you had conversations with the PUC about the program, so the future of those program savings. I mean, we're working with them on sort of what the -- well, I guess backing up a little bit. Historically, right, the -- each portfolio, you know, every few years the -- the ratepayer funded efficiency programs kind of get a refresh and it opens up sort of new wedges that wouldn't necessarily be in the out years of this forecast. Right? And so you'd kind of expect this forecast to have a tailing off over, you know, the five last, five final years of this forecast period.

So historically like this isn't a surprise, I think, because there's some sort of new unknown savings, you know, be a program approach or widgets or whatever that sort of will fill in above that green to sort of make it flat, right? That's historically kind of what's happened. You know, that's what innovation's all about.

I guess so the question I would have is are you taking into account the kind of the fact that the ratepayer funded programs are kind of projecting that they're going to have actual declining savings over time, like that they are having a harder time finding cost effective savings in the efficiency portfolio. That seems to be the conversation that's playing out at the PUC, for example.

MR. GARCIA: Yeah. I can't answer that right now primarily I haven't gotten to that level of detail on this. I know we have some staff here that worked on committed savings.

Ingrid, would you be able to respond to that?

COMMISSIONER MCALLISTER: I mean --

MR. GARCIA: I should mention my other name is the chief aggregator so a lot of this data comes to me and I do my best to understand all the bits and pieces.

COMMISSIONER MCALLISTER: I mean, this is a conversation we've been having in the context of the Efficiency Action Plan which, you know, staff has been working busily on for many months now.

MS. NEUMANN: Okay. Hi, this is Ingrid Neumann. I did the AAEE portion for this. So I believe Cary's discussing the committed savings that go into the baseline forecast.

COMMISSIONER MCALLISTER: Uh-huh.

MS. NEUMANN: So what you're discussing is in the PG study that is used for the AAEE.

COMMISSIONER MCALLISTER: Right.

MS. NEUMANN: So that decline is seen there.

COMMISSIONER MCALLISTER: Okay.

MS. NEUMANN: So that's what he'll be discussing in the minutes forecast, probably. This is the portion of codes and standards and IOU and POU programs that are in the committed.

MR. GARCIA: Yeah.

COMMISSIONER MCALLISTER: In the committed. Right.

MR. GARCIA: But I think Andrew's getting to has there been in the previous iterations of committed savings, has there been more of a decline relative to -- based on these issues with ratepayer funding?

COMMISSIONER MCALLISTER: I mean, the goals right now are defined now for the portfolio going forward and they're actually smaller than they have been historically. And the spend is likely going down on those programs so that would expect that to be reflected here.

MR. GARCIA: Yeah. The program savings is going to be coming from the CPUC's -- I'm blanking on the name of that database.

MS. NEUMANN: So I don't know. I can't speak to the what's in the baseline forecast other than specific committed codes and standards were included in the baseline forecast and then those were not included in the AAEE because that is supposed to be incremental --

COMMISSIONER MCALLISTER: Right.

MS. NEUMANN: -- to the baseline forecast.

So you can see how he has the newer building and appliance standards. So for example for Title 24, the 2019 building standards that don't go into effect until 2020 are included here with the committed savings. Right? But future code cycles are not included here but rather they're included in AAEE.

COMMISSIONER MCALLISTER: AAEE. Okay.

MS. NEUMANN: So the potential of goals that the CPUC is putting out and their projected decline in savings, I don't think that's what you're seeing here. That's what you'll see in AAEE.

COMMISSIONER MCALLISTER: Okay.

MS. NEUMANN: I would suspect that this is what you would normally see, right? Because these are not -- these -- the program IOU and POU programs savings here are existing ones not projected ones, not in the goals --

COMMISSIONER MCALLISTER: Yeah, exactly.

MS. NEUMANN: -- that you're referring to.

COMMISSIONER MCALLISTER: So eventually you'd have some AAEE that pumps that green line up --

MS. NEUMANN: Right. And it's not as much this time as we've seen in the past.

COMMISSIONER MCALLISTER: Yeah. That's my -- I guess my question is --

MS. NEUMANN: That is true.

COMMISSIONER MCALLISTER: -- what -- what is the recent work for the new portfolio over at the PUC incorporated into this baseline. It sounds like the answer to that is no, which is okay.

MR. GARCIA: Yeah. I -- it's -- as I mentioned, it's 2018 to 2019 --

COMMISSIONER MCALLISTER: Yeah, okay.

MR. GARCIA: -- what's happening there. And there is some -- there are some programs that occurred before then that are still embedded in the forecast, and we just added the 2018, 2019 as they were --

COMMISSIONER MCALLISTER: Okay.

MR. GARCIA: -- given to us by --

COMMISSIONER MCALLISTER: Okay.
MR. GARCIA: -- CPUC.
COMMISSIONER MCALLISTER: I see.
MR. GARCIA: But Ingrid brings up a good point as well, though, which is that I think you're correct in that if you're seeing these changes to that portfolio happening now but when we get to 2021, for example, we should start seeing some changes based on that. And that's something we can follow up on to get a conclusive answer to that.
But Ingrid also brought up a good point in that you are seeing it in the potential goal study in that the additional achievable energy and efficiency has been cut almost 50 percent in comparison to the previous versions of AAEE that we've had in the past. Or actually comparison to 2017 which was the most recent one prior to this 2019.
COMMISSIONER MCALLISTER: Right, got it.
MR. GARCIA: So that effect definitely is getting captured there.
And this brings us to AAEE. So you can see here -- there are various flavors of AAEE. So we have -- start at the very bottom there. So you'll see the high -- the first -- the first part of each scenario is essentially the demand scenario. So a high demand

scenario at the top there on the blue -- sorry, at the top of the legend, not the top of the graph.

But that's matched up with an AAEE scenario which in this case that blue line would be the high demand with the low energy efficiency impact. And then you see the various flavors of that as you go through. As I mentioned, we primarily focus on the Mid-Mid, that green line there, and the Mid-Low which has the more conservative amount of energy efficiency.

So that Mid-Mid, as you can see, is around 16,500 or so gigawatt hours by 2030. And as I just mentioned, that's about half what we've previously had in our Mid-Mid scenario for energy efficiency savings for these additional achievable energy efficiency savings.

And you can see the more moderate Mid-Low scenario around 12,000 gigawatt hours by 2030. And way at the top there, the Mid-High plus, assuming a far greater amount of efficiency savings over time with additional programs occurring there along with standards and all the other bits and pieces that are at play in there.

But I'll show these a little bit more and Nick will have these as well looking into the effects on the demand forecast when you apply these scenarios to the individual planning area forecast.

So these will basically, I'm showing energy here but they'll also drive down peak demand as well. And Nick will have modeled that on an hourly basis which we've done this year for AAEE savings.

So getting to our cultivation forecast. So as I mentioned, we've been developing a new forecast product focusing on cannabis cultivation. And just to start off, I mean, there's really some challenges here. These are pretty big ones that create a lot of uncertainty in what you would -- in developing a forecast, particularly some of the high and low scenarios around it.

So first of all, historical data on production and consumption is going to be difficult to find, particularly when you have an industry that has been illegal for quite a while. There's not a lot of information getting shared. You know, people keep that in, you know, just general users of cannabis may not be willing to share information about that. And you also have underground production that was occurring in the state.

There's also a fair amount of uncertainty around energy intensity of the cultivation. So what types of -- what types of, you know, methods will you use to cultivate it? Will you use indoor version of this which is more energy intensive, probably the most energy intensive. Outdoor which is the least energy intensive. Or somewhere in the middle, use a greenhouse which kind of takes the best of both worlds using sunlight along with some, you know, modifications for lighting.

And within that, you have the energy intensity, obviously, but there's also different rates of production for those three different methods there. There's some benefits to using indoor and greenhouses in that you get to cultivate more often during the year versus outdoor, you're kind of limited to the world's natural seasons.

And then you also have the noncommercial home operations that can be occurring as well that are difficult to capture. So those would be things like, you know, just the fact that there's -- I think you can have up to six or so plants just depending on, you know, cities and county regulations. But that can be occurring as well that would be driving up residential electricity demand.

But once again, that's difficult information to capture, there's not a lot of data yet about that. But that could influence the uncertainty around our forecast here.

So the basic method for the cannabis cultivation forecast starts with estimating California usage of the products. So let's -- that basically breaks down to how many users are there and how much are they using? So we relied upon the Substance Abuse and Mental Health Services Administration, SAMSHA, to calculate this information. And we also accounted to underreporting that could occur as I mentioned, as that would be something that we would expect given the transition from -- or looking at historical data when it was illegal versus now where it has been legalized. And so using some literature, we account for that roughly a 22 percent adjustment for underreporting that may be occurring.

And so once we estimate that baseline of users and amounts, we need to forecast the number of users that are going to be -- that we expect to continue to use and then also because of legalization, we would expect additional users to come on. And so the main driver here is essentially population growth. So heavy users are expected to keep using generally the way they have been. But similar to other states when we look at Washington, Colorado, you see this uptick in usage from new users that otherwise seem to know that it's legal, they kind of jump into that realm and want to use a little bit more than they have done previously.

There's also another bit where we have to rely on literature as well to account for exports that occur.

And this could change quite a bit given that, you know, legalization is starting to -- it seems to be in the West Coast, perhaps, and other states are now legalizing. So Nevada, for example our neighbor next door, was most recent in 2017. And so that could add a lot of changes. So if you have other states around you that are cultivating themselves, you would -- you could essentially have less exports occurring because there's no longer needed in those states.

But right now, based on literature, roughly a 3 percent multiplier has been applied to account for those exports that will occur. But as I said, you know, things can change and legislation can change state by state. Federal legalization is something that could come up and that could cause some changes and require some adjustments to this current forecast.

COMMISSIONER MCALLISTER: So just to be clear, that's a 3 X, right? That's a three times.

MR. GARCIA: It's three times.

COMMISSIONER MCALLISTER: So -- so three-quarters of the cannabis cultivation in the state would be still illegal. So, yeah, that seems like a pretty important number to get a good handle on if we can.

MR. GARCIA: Yeah. Yeah and -- I mean, it's not baked into this forecast but I know that in the recent news, I believe there were some increases in some of the taxes on that. That’s something that we have -- hasn’t been addressed here, but that could also be causing some changes.

COMMISSIONER MCALLISTER: Taxes on the legal.

MR. GARCIA: On the legal, right. So if you’re talking about, you know, black market cultivation, I believe the news is sort of saying, well, it’s pretty clear you raise the prices on legal products, then suddenly there’s an increase demand for black market if it’s cheaper.

Obviously there’s some caveats with that. You know, theoretically the state would be a safer product because it’s regulated, it’s tested. So there -- there’s some tradeoffs there, but generally you expect, you know, an increase in those taxes and the cost of it would -- would make black market products more -- more likely to get purchased.

MR. RIDER: May I ask a question?

MR. GARCIA: Yeah.

MR. RIDER: Just on the intensity there, you know, California electric rates are significantly higher than surrounding states. And so just as a question, you mentioned, you know, three times multiplier on the exports.

Is that mostly a certain type of grow -- because thinking about, you know, if Oregon or, you know, I don't know where you're thinking this is getting shipped but, you know, if it's legal there, you know, the electricity rates are much lower so it makes sense that actually -- you would think offhand that the more energy intense versions of the production would migrate to lower electricity prices.

So I'm curious as to what factors -- and maybe I can dive into this if it's in this report, but what factors make California the primary -- like with our high electricity prices, why we're such a primary grower and supplier to the surrounding regions.

MR. GARCIA: Yeah. As I mentioned earlier, I did not prepare this particular part of the forecast.

MR. RIDER: Yeah, I understand.

MR. GARCIA: I wish I had that information but I could follow up with you and dig into -- we have a draft report that we have so we could share that with you and get into the specific details of that, how that multiplier was developed. But I can't answer that right now. I'm sorry.

But I think what you're saying does makes sense. There are some -- I was trying to get to that. I mean, there's a lot of uncertainty around how these other states operate. And your good example is like electricity rates, right? Even within the state, as electricity rates change from planning area to planning area, you'd expect people would move their operations to different areas. That may not be as easy with a large-scale operation but it could have an impact for sure.

Getting into that -- some of that production. So we relied upon California Department of Food and Agriculture looking at the percentage of permits given to different -- different types of growing operations. So outdoor here shakes out roughly to about 20 percent of the gross. And the other portions are primarily greenhouse, as you mentioned.

You know, some of those electricity rates, you're going to have sort of a middle group on balancing the amount of yield you can have along with the cost in comparison to indoor. So that greenhouse ends up being the predominant -- predominant permit that is getting applied for or is actually permitted in the state.

As I mentioned earlier, that forecast was roughly around 12,400 gigawatt hours in our mid case for -- for that cultivation. But there's a lot of uncertainty around this so we've spoke to our expert panel getting some input. Thus far, the preliminary comments were that the mid case does seem reasonable given some of the uncertainties. But we still want to dig into what would be appropriate like high in demand cases that would capture that uncertainty.

As I mentioned, we could -- it would be helpful if we had more data on the number of users of each type, heavy and light. Hopefully we'll get more data on that as legalization is no longer a new trend in this state or across the -- across the country. We want to understand like how much are people using, what is the actual production? That's hopefully something we can start getting from the state in terms of like CalCannabis. I think they're, you know, a fresh agency, but as I think more data comes in, we start getting more information what the production is, what the tax information is, and what's getting sold out there.

And also we'll start getting more information. I mean, we have the current permit data but we'll be getting, you know, as we get more and more data, we'll see how things shake out between indoor and greenhouses. Those are two dramatically different levels of energy usage there, as I mentioned, so that energy intensity is going to change.

In the forecast as we applied it, right now it's pretty basic using population to share out a statewide forecast to the different planning areas. It might seem pretty crude at first and it is for right now, but when you look at that permit data, ultimately you see as I kind of broke out this information, this outdoor, indoor, and greenhouse is what you end up seeing is the heavily populated areas are also getting the indoor operations was their most energy intensive, whereas the lower population dense areas are going to the outdoor operations so they would have lower energy usage overall.

So for right now that works, I think it's our best estimate. But hopefully we can leverage some more of this permitting data. And as I said, getting more information on actual production that's occurring at these facilities would be very helpful to improve upon this forecast.

And then ultimately right now, we're adding it to our agriculture and water pumping forecast. That seems to be the best fit. We can always tease it out and move it to different sectors as appropriate. You would expect there would be a small increase in like side operations, for example, not just cultivation but the processing to make different products from it. But right now, that seems to be very small according to the literature than otherwise could be captured in something like commercial sector model, for example. But just like any other business that would be out there.

All right. So I am -- spent a lot of time on cannabis cultivation, more so than I was expecting. So I will try to dig into the state results and leave time for the rest of our presenters.

So getting into the statewide results here -- sorry, there's something in the way there. This is looking at the baseline economic and demographic information for our latest high, mid, and low scenarios that you see there. And then I put a note there for the mid demand scenario from the previous forecast that we developed.

So as I mentioned before, we do see that population growth from 2019 through 2030, our forecast period, does decline, is reduced in comparison to 2018. Households overall does see an uptick in comparison to 2018, whereas personal income, manufacturing output are -- are reduced a little bit, manufacturing output in particular.

Manufacturing output would not be something we wouldn't expect. We've seen industrial load in the state and resource abstraction, for example, on the decline, which has kind of been going on for the better part of a decade.

And then total employment. So here total employment seems, you know, about level with the previous mid demand case but planning year by planning year this starts changing. And employment's an important driver for our commercial forecast in that the driver for that commercial forecast is commercial floorspace which uses employment by different sectors -- or employment by different sectors to map to a specific building type. So small office, hospitals, schools, different types of building types where floorspace is important to do those projections for the commercial forecast.

So if you see a -- start seeing declines in employment and as I mentioned before there was sort of this -- there's sort of a negative growth in employment occurring in 2021 and twenty -- and slower growth through 2022. It begins to take off you will see like a dip in that consumption in sales in the near term and then it slowly starts to rise out of there as there's -- and this is typical in economic projections. Nobody really predicts a recession, nobody wants to be that guy. What they generally say is, okay, things are going to slow down a little bit and we're going to slowly climb out of it which is kind of -- it seems to be the economists' best guess of what will happen without saying yes, a recession is going to happen.

And vice versa, we sort of see things -- you see a similar phenomenon when you're looking at okay, how are we going to get out of a recession? You'll see things like oh, we're going to get out of it now. Nope, we're going to revise it. And so it's a little slower and slower.

So I think we're kind of in that phase right now where there's a lot of uncertainty, we do feel -- a lot of economists I think feel like there's going to be sort of this dip in employment. At some point we're riding pretty high on the employment growth for the better part of the last five years or so. So I think there's an expectation that's going to slow down a little bit but not quite a full recession yet.

Okay. Another input that I mentioned is electricity rates. So this is on a statewide basis, looking at the overall increases in rates. You can see fairly significant increases over the forecast period, particularly this is going to occur in more of the nearer term. But those are pretty dramatic here. And so we've included updates for the PG&E and Edison's distribution revenue requirements and that's going to be based upon a lot of this wildfire mitigation that's going to be added to the ratepayers here.

And then some less -- less dramatic increases for San Diego Gas and Electric. Although the latest information from the general rate cases has been included in the forecast. But by comparison, you can see in the 2018 much lower rates, pretty flat there. Whereas now we see these increasing rates in the forecast. And they do have an effect on particularly -- I highlight residential and commercial because those are going to be the most sensitive to these rate increases that are forecast.

So looking at consumption. So consumption is going to be the end-use electricity demand that includes self-generation as well. So behind the meter PV and other forms of self-generation.

Some mid case, as I said, is going to be brought down a little bit and slowed in comparison to 2018 because of those drivers that I was mentioning before, those effects that occurring in the residential and commercial sectors. And this continued decline and industrial and resource extraction through the state.

So ultimately by 2030, you can see there are roughly 320,000 gigawatt hours in comparison to our -- our previous forecast, that dotted line. I should lay out the demand scenarios in case it's a little hard to see. So that dotted line you see at the top there was our previous forecast, our mid case forecast from the 2018 update. The red line is our high demand scenario. And that green line at the bottom is our low. And then that dark blue line in the middle is going to be our best -- our baseline scenario, our mid case.

And these are baseline forecasts so they only include those committed savings impacts, they don't include the additional achievable energy efficiency savings.

So here's the sales results. So the difference between that previous forecast and this is simply subtracting out the self-generation impacts from PV and other components. And so that's what's going to cause that slope, sort of a dip down there, this curve, as PVs growing faster in the near term and sort of tails off -- tails off towards the -- the longer term -- longer term portion of the forecast.

So overall, average annual growth is about half a percent comparison to almost 1 percent in the previous mid case. One important change here is that in the 2018 update, we sort of had another AA scenario which had AAPV for the Title 20 for impacts for solar on new home construction. So this now has been baked in to our baseline forecast. So that's going to add an additional PV that otherwise wasn't in the update forecast. And that will be coming -- Sudhakar will talk about that a little bit more coming on line in 2020, relatively soon.

So that's also going to drive down that forecast there so you see sort of like a hockey stick on the bottom as that comes online in 2020. But then you have the other components like the electric vehicles and other things adding to the forecast that continue to drive the forecast up.

But, yeah, and as I note there, so you see that faster growth in PV in the near term whereas the long-term source starts tapering off. So that's what's causing those differences in that trend line between the previous mid case and the new one.

Looking at baseline sales results by sector, this is basically the 2019 through 2030 component average growth rates for various increments from -- of years. Sort of a mid-scenario or a mid- -- a near-term 2019 to 2025, you see that slower growth there. Whereas growth starts picking up in the medium to long term and then over the forecast, that shakes out to about 1 percent as you can see in that residential sector.

Commercial, we do see that decline in electricity sales and so you're going to have that PV growth there but you'll also have just a lower consumption forecast as I mentioned from the decreasing employment which is going to drive that commercial floorspace projection which is going to then drive the commercial sector demand. So if you have lower commercial floorspace, you therefore have lower commercial sector demand.

Additionally, you'll have those committed savings estimates that I showed affecting the baseline consumption data which also drives things down a little bit. But those start decaying off over the -- over the forecast period. So the forecast starts creeping up once again.

And you see some other pieces here, as I mentioned. Slower floorspace, some person per household starts decreasing which could increase your residential -- or decrease your residential electricity usage. And then the increasing rates that I showed before also contribute to slower growth in those commercial and residential sectors.

Industrial, as you can see, continuing to decline a little bit faster than previously. Mining as well raise some extraction. When you see the Ag bump a little bit -- bump up a little bit, that's not typical, usually it's pretty flat. But since we added that cannabis cultivation to the Ag forecast, you see this increase in that over time.

And then you also see some trends in street lighting, essentially efficiency occurring there that's driving down the street lighting forecast, so LEDs and things like that.

Any questions on the statewide? Going to try to jump in to hear Marty a few minutes over -- a minute over time.

So the next presentations I'm going to give are getting into the planning area. So these first slide, I'll give a little bit of an input summary showing what the major drivers are and some of the pieces and I'll get into the baseline scenarios, sales, and some of the managed scenarios. And for the IOUs, I won't get into peak, I'll leave that to Nick later today.

So as I mentioned, we have those increasing rates for PG&E here. And as I -- along with -- in comparison to the rest of the state, we have less household growth that's getting added in the near term, so that's going to be driving down your residential forecast. And those increasing rates will also influence the commercial sector as well. And along with that, you'll see -- there's a larger decline in employment in 2021, so essentially dipping down. And then that longer term growth is a little slower compared to 2018.

Below that is just some pieces for the PV energy you can see still growing pretty well, almost 9 percent in the forecast. Light-duty vehicles add some additional consumption as well as the medium and heavy-duty vehicles there, showing those 2030 figures.

Similar graph to the state but looking now at

PG&E for baseline sales. As I mentioned, the commercial and residential sales are going to be lower due to those drivers that I mentioned before. You could even see a decline in commercial sector sales in that midterm and relatively little growth over the long-term forecast.

And similar issue with the -- with the residential sector. And you can see the Ag sector there bumped up a little bit. That's because there's about 600 gigawatt hours of that cultivation being added to the forecast, along with some increases in crowd production and municipal water supply usage.

And then similar, you'll see this across the state and I think all planning areas will have that decreasing and street lighting usages as I mentioned to the efficiencies that occurring there.

So this is a graph of the sales results here that I just showed but just aggregated up for all the sectors combined. This mid case, the growth is pretty flat. That carve out you see in the bottom looking at the mid case is essentially that PV coming online and growing faster in the near term, and it starts to taper off and so you end up seeing increase in demand over the forecast period but a decline in that near term. So right in that -- through 2021, the PVs actually -- energy is actually growing at 18 percent per year which is pretty significant causing that sort of hockey stick-like shape there on the bottom.

But overall, because of those declines in overall consumption or slowdowns in consumption due to those drivers, you do see a slower rate of growth here. Nearly flat for sales in comparison to under one percent in the 2018 forecast. And we're also coming in at a much lower starting point, the 2018 sales were a lot lower. And that gets driven down further by those committed savings coming on line in 2019 and stay pretty -- pretty relevant through 2021, 2022.

And those begin to taper off along with the PV and the other pieces that while light-duty vehicles and all these other additions start bringing the forecast back up out of that dip there. So essentially, those other demand modifiers are outpacing the PV growth there along with the committed savings.

This is kind of a blown up graph, it looks more dramatic here because it's definitely zooming in, right, to 2019 to 2020. But this is comparing our Mid-Mid and our Mid-Low AAEE scenarios for the sales results. And you can see pretty clearly the Mid-Low is more conservative here, roughly at 3300 gigawatt hours in 2030, whereas the more optimistic Mid-Mid base case is around 6,000 by 2030. But overall, the Mid-Mid will reduce those baseline sales results that I showed here by about 5 percent in 2030 when those savings are added to the forecast.

Edison, similar story, you have increasing rates that are going to affect your res and commercial. But less of a decline in employment here in comparison to what we had previously. So you don’t see as much of a slowdown in comparison to some of the other planning areas.

PV energy results, still quite a bit, roughly growing at 9 percent per year. And then the light-duty vehicle consumption as well as a fairly significant, although medium heavy duty is still somewhat small in comparisons to the other components of the forecast, it is growing quite a bit in our mid case as you can see here from about 5 gigawatt hours to almost 450.

Yeah, so commercial sector, as I said, not hit as hard so it remains relatively flat. You don’t see those declines in commercial sector sales that you saw in the PG&E’s planning area. And then the residential sector also is not hit as hard, although it is -- this is a slowdown in comparison to our previous forecast. So you can see the commercial and residential sectors are down 6 and 7 percent, respectively, in comparison to that 2018 update forecast.

Looking at this graph, you do see we're kind of similarly in -- rough -- close to the same starting points that we were before, but now there is still a slowdown in comparison as well as that PV growth there carving out a little bit of a dip. But as I mentioned, Edison is not as nearly as impacted as some of the other planning areas by the changes in the economy. And so ultimately sales slows a bit but roughly about half a percent versus 1 percent in 2018 reaching 104,000 gigawatt hours by 2030 there. But ultimately, this ends up being about 4 percent lower than the 2018 update.

Looking at the managed forecast as I showed before. Similar story, the Mid-Mid ends up dropping about 5 percent off the baseline sales case. And you see the difference between those -- the conservative Mid-Low versus the baseline managed case, the Mid-Mid there.

Some of those -- some of those kinks in there, some changes in rates that are happening year to year. So that's what's going to be causing -- and we're also zooming in quite a bit so some of these changes seem a little more dramatic than they otherwise would.

San Diego's input. So San Diego here did see a decrease in employment. Like PG&E, they had a -- a greater decrease in unemployment in comparison to the previous economic data that we received. Household additions also dips in 2020, so they're still adding households but it's that growth is actually much slower in 2020 and then it starts picking up again. And this is going to be a little different than 2018.

But the rates see modest growth, but nonetheless in the 2018 forecast that are almost flatter declining, whereas now we do see some growth, although they're -- they don't grow as rapidly as PG&E and Edison's territory.

And then the bits and pieces there. So still significant growth in PV energy. Light-duty vehicles are adding to that consumption in that big change in medium and heavy duty comparison to our 2018 forecast. In comparison to 2018, the medium and heavy duty is relatively flat, but now we see these new technologies come into play. And our transportation forecasting staff will talk about that more later.

So mentioned there's some -- some sort of growth in the residential and commercial sectors. As you can see, as I was showing before, although Edison didn't have that decline in employment, you can see the impact of what's occurring here in our commercial sector. That near term decline in employment which -- and slower recovery from that leading to an overall commercial sales forecast in comparison to the update.

Residential sector, as I showed -- or as I mentioned, that near term, there was a slower increase in those households. This starts picking up and grows a little bit faster over the long term. And then sales ultimately grows roughly 1 percent. Industrial sectors still on the decline which is not anything new. And then the Ag sector appears to be growing tremendously but it's relatively small for San Diego and that's going to be the addition of that cultivation there. And then once again, street lighting, seeing some savings occurring in the forecast.

So looking at the sales results. Slower growth in comparison to the mid case but growing at just under half a percent annually in our mid case, which is roughly 6 percent less than 2018 -- the 2018 forecast in 2030. Roughly 19,000 gigawatt hours. And you can see the differing trends between that mid case and the 2018 update versus what we have now. And that's going to be a much faster PV adoption in the midterm in comparison to what we had in that update.

So you can see the -- that belly that starts to form there as the -- we would essentially start out with consumption, carve out the belly with the projections of self-generation. And you can see it has a much different trend in comparison to the 2018 update there.

MR. RIDER: Cary.

MR. GARCIA: Yeah.

MR. RIDER: Can you explain the residential difference here in San Diego Gas and Electrical? It’s quite a bit -- well, at first it starts much lower and then it goes -- it’s the most dramatic difference, I guess, compared to any other service territories. It’s quite a big change between the initial five years and then the following.

MR. GARCIA: Yeah. So what was occurring in the -- so looking -- the big driver for the residential forecast is going to be your households growth, so what the households. And so I noticed the same thing. And so digging into the household projections, what you have is in the 2018 forecast, you didn’t have a decline. It was sort of just steady growth over the long-term forecast. So just a nice even line.

What’s happening now is you see the growth come on, slower growth, and then a faster recovery. So that’s why you get this kind of -- along with some increases in rates, but this is adding to that decline in the 2019 to 2025, and then it starts picking up more rapidly in 2025 to 2030 over the forecast.

MR. RIDER: Driven by population growth, economic growth or?

MR. GARCIA: This is household projections from Department of Finance. Yeah.

MR. RIDER: All right. Thank you.

COMMISSIONER MCALLISTER: So just to be clear, that's just -- the Department of the Finance believes that there's going to be a dip and then a surge in the latter half of the decade?

MR. GARCIA: Yeah, that's happening -- this is not -- this is special to San Diego. I'd have to dig in with Department of Finance to find out specifically why. Because San Diego is pretty straightforward because it's county to county mapping, unlike some of our other forecasting zones.

But I'd have to double check with finance to find out what exactly is causing that. It's not -- it's not the same as some of the other planning areas. Some of them do see generally, like I was saying, they'll have a slower growth and maybe a little bit of a dip, but San Diego actually declines quite a bit just right off the bat and then just bounces up really quickly.

COMMISSIONER MCALLISTER: It would be good to have that -- good to have that insight.

MR. GARCIA: Okay. Yeah, and then here's our AAEE impacts. So across all the most of the planning is roughly a 5 percent reduction, as you can see, 4½ to 5 percent reduction. But ultimately our Mid-Mid reaches roughly 18,000 gigawatt hours by 2030 here. So 900 giga compared to the other planning areas, San Diego's relatively small compared to them, so you see less AAEE impacts overall here. So on a scale of 900 to 600 between the Mid-Mid and the Mid-Low cases. Triple digits in comparing to the four-digit impacts that you see in the larger places.

Moving on to LA. Also seeing increase rates here relative to 2018. And also a larger decrease in the 2021 employment in slower growth. Over the long-term, PV energy growing fairly well, 8 percent over the forecast period. And then you see the impacts there of light-duty vehicles that are baked into the forecast. Along with the growth of medium duty and heavy duty vehicles.

So residential and commercial sector once again have been reduced, growing at 1.9 percent and 1.1 percent, respectively, in the previous forecast. So a little bit slower in the commercial sector, as I mentioned that dip in that employment driving those floorspace projections. And then slight decrease in the residential sector growth, but not as dramatic as some of the other planning areas or San Diego that I showed before.

And then Ag sector, a little bit's getting added here as well. So you can see how that tremendous increase. And so that's going to be -- it's expected that that would be indoor operations that would be occurring in the LA's territory. And then once again, street lighting is -- is pretty declining and industrial and mining sectors, heavy manufacturing sectors are on the decline as they have been previously. But that's a steeper decline than -- and across all the planning areas, we see a steeper decline in those industrial mining sectors.

So here we see some fairly significant change between what we've had before and what we have now which actually puts us more in line with what we've -- with the projections provided by LA, DWP, through the IEPR process when we do those comparisons. So sales growth is just under 1 percent now versus 1.2 percent. So that trend didn't change so much, reaching almost 2400 -- 24,000 gigawatt hours by 2030.

We found that the 2018 actual sales were far lower than what we were predicting so in the 2018 update, we were starting with 2017 actual of data, expecting that to continue to grow. But we ultimately had a decline in 2018 which will bring the forecast starting point down a little lower. And then you're adding to that committed savings estimate that would drive that 2019 value even further down.

So looking at net peak results. And I'll mention, I wasn't able to -- yeah, okay, I have it here. I wasn't able to do the -- we typically will do an AAEE peak, but we haven't been able to finalize that yet, so we'll have to work on that this week. So I'll just be showing the baseline net peak results here versus some of the POUs territories. SMUD will be the last one.

So we're growing quite a bit slower in comparison to what we previously had. Half a percent versus one percent in the 2018 update reaching, as you can see here, 6300 megawatts in 2030. But these update projections are more in line with LADWP's IEPR forecast growth. Looking at how we've done this previously. So we don't have -- we don't have an hourly forecasting model yet for LA and SMUD, for example. It's something that we've been trying to work on in the future. We rely on load factors by particular end-uses that are developed from our previous HELM model, hourly electric load model.

So what I did there is I just recalibrated some of those load factors to better estimate what the contribution of consumption, the peak load would be, that translation from end-use consumption to peak load. By adjusting that factor, we end up with something a little more in line with what twenty -- with what LADWP is projecting. This came up in our preliminary forecast, we had dramatically different forecasts. So hopefully that adjustment will hold well. But once we re-fab our HELM model and that continues to get developed, we'll be able to retool this a little bit more and dial it in. But yeah, I'll leave it there.

Jumping back to sales, this is just a quick slide of the sales forecast here with the AAEE applied to it. So reducing quite a bit of AAEE savings in the Mid-Mid scenario here. I mean, reducing sales by about 16 percent so you end up seeing a declining sales estimate over the forecast period whereas that more conservative estimate of AAEE savings ends up with a flat sales forecast in that Mid-Low and that green line there.

So going -- saving the best for last in the home -- the home utility. Once again, near-term household growth is slower but -- and ultimately total additions reduced by 2030. Long-term employment here slowed with a much larger dip in 2021 in comparison to the previous forecast. And we also see a slower growth in population.

PV energy growing a little bit more over the forecast period, 11 percent versus 7 percent. And there are light-duty vehicle and medium, heavy-duty contributions to the forecast.

So as I said earlier, so that you see that reduction and near-term household growth reducing that residential forecasts. The slow downs and commercial sector also reducing, reducing the sales forecast.

Declining industrial, it does dip up a little bit. But mining, obviously, I don't see any much resource extraction happening in the Sacramento County area, but that is expected. And a little bit of Ag getting increased and that's due to about 70 gigawatts of cultivation impacts getting added to the 2030 by -- getting added by 2030.

But ultimately the two big drivers here, as I said, commercial and residential -- commercial and residential sectors, I should mention this before is roughly 80 percent of demand in the state. And so that's why I kind of key up on those two big -- big drivers there. They're the ones that see the most action particular. But these have been reduced a fair amount in comparison to our previous estimates.

And so when we get to our baseline sales forecasts, you see a reduction as well overall when you combine all the sectors together. So just under 1 percent growth versus almost 1½ percent in the 2018 update there. So 11,300 gigawatt hours here. So that's compared to the 12,500 or so that we had before.

So this actually also puts us pretty in line with what SMUD has provided. I think they're in the process of updating their forecast again for September. So we'll have to see what those look like as well to do our comparisons there.

Looking at peak results. 3200 megawatts by 2030 because you have a consumption in sales forecast to reduce, you're also going to have a reduced net peak result. And so the annual growth here slows a little bit from those drivers that I mentioned before. But, you know, not too -- not too different of an actual growth pattern but more of an adjustment downwards from the new starting point.

And then looking at the manage sales. Little bit less AAEE than some of the other planning areas, but that still reduces the forecast a little bit so the Mid-Mid is actually declining here as you can see in that blue line. Actually -- or growing, I mean it's declined but it's growing at 0.3 percent versus a half here. So roughly 0.8 that I had in the previous slide there. And then 1300 gigawatts of AAEE that's being impacted in 2030.

So I think that's it. I've already wasted 23 additional minutes from my previous speakers. But are there any questions throughout this? I can jump back to anything. Do my best to answer them.

VICE CHAIR SCOTT: Yeah. No, not wasted time at all. Thank you for the thorough presentation.

Other questions for Cary?

COMMISSIONER MCALLISTER: Yeah. I guess I'm a little surprised at the -- so, you know, we talk a lot about how transportation is going to be this big new load. And, you know, we're looking out to 2030. And maybe with the exception of Edison and kind of, you know, SDG&E is a unique case. But it looks like the long-term managed forecasts are pretty low and there's sort of not out to 2030 at least, this big wedge of, you know, the numbers for gigawatt hours consumed by electrification transportation don't seem to be overwhelming the rest of it.

So I guess that's a little bit of a surprise to me. I wonder if it is to anybody else. You know.

MR. GARCIA: Yeah, you're -- I mean, you're coming in with -- so first we'll estimate the consumption by the particular sectors. So we have -- so we're just keying up on residential and commercial sector, for example.

Looking at the -- we start off with that consumption forecast, and that's already getting driven lower in comparison to what we've had before. And so that's our starting point.

And the way we apply the transportation forecast that's getting layered upon that lower forecast already. And then you start adding on the sales -- or the reduction in sales from PV generation that's still declining. So you end up with this end -- add to that the committed savings that's coming online. So that's all getting baked into there just kind of pushing that forecast down further and further.

So even though the transportation is adding quite a bit, you do kind of see -- like you can see here, it sort of kind of dips back up. So that savings is coming away. Let me jump back to -- to PG -- to San Diego, for example.

So it does have that dip, but that -- additional consumption from light-duty vehicles and electrification is adding to the forecast. It's bringing us out of that because otherwise, you would have something that would have -- I'd have to do the counterfactual and say what if transportation didn't happen and see what these forecasts look like.

My guess would be that you wouldn't see this increasing in the longer term. Because the transportation is still relatively -- there's quite a bit of electrification occurring, but that -- those big changes are happening further out in the forecast period, we're adding, you know, 3 million vehicles or more.

COMMISSIONER MCALLISTER: Yeah. Well, San Diego you said that -- I mean, we saw the numbers for a population growth basically being in those out years as sell. So there's some driving there.

I guess I was looking at PG&E and DWP, and SMUD, I guess, where basically the net was pretty flat even in the out years. Which is actually okay. I mean, the idea with efficiency and, you know, the other demand. You know, the distributed stuff is it creates headroom for all the new load that's going to come in for electrification vehicles and heating loads.

So that's great. I guess just want to make sure we're -- we're seeing what's adding and what's subtracting and making sure that each component is reasonable.

Thanks.

COMMISSIONER MONAHAN: I'm assuming that in the next presentation, we're going to go over the numbers of actual electric vehicles that we're looking at. And I think they're not very high either. So I think there's multiple things happening.

Yeah. I mean, Cary's right that it's -- it really is an out year thing. Because even if sales really escalate, it's the replace -- it takes a long time to cycle out the entire fleet. So with the 15-year-ish life span of light-duty vehicles and even longer with heavy-duty vehicles, it takes a long time to cycle them out.

VICE CHAIR SCOTT: Other questions for Cary from the dais?

All right. Thank you, Cary.

MR. GARCIA: All right. Thank you.

VICE CHAIR SCOTT: So we are at about 11:30, we'll go till 12:30 for the transportation forecast. So we'll give that the hour that we're looking for.

And it looks like Mark is going to start us off.

MR. PALMERE: Good morning, Commissioners and Ken. As well as the stakeholders and members of the public. Thank you all for being here.

My name is Mark Palmere and I work on the Light-duty Transportation Vehicle Forecast. And today we will be presenting on three different parts of our forecast. I'll be presenting light-duty vehicles. And then our freight specialist Bob McBride will be presenting medium and heavy-duty vehicles. And finally, our forecast lead Aniss Bahrenian will be presenting about overall field consumption.

So to start with, here is a broad look at our model and how it works. And if you've been to any of our presentations before, you've probably seen this. But I know some of you are relatively new so I just wanted to very quickly go over it.

And we have a wide range of inputs from our vehicle survey which assesses consumer preferences to economic and demographic data, fuel price forecasts, vehicle populations, vehicle attributes. And vehicle attributes are -- can be influenced by policy regulations such as CAFE. And finally, there's also the incentives which are another input into our model.

And those influence each model in different ways but in general, they give an idea of what we're expecting over the next ten or so years. At our model, we have a personal vehicle choice model, commercial vehicle choice model, and that's light-duty commercial vehicles, government and rental model, truck choice, aviation, and other bus. And all those lead to our outputs of vehicle stock on the road and transportation energy demand.

And a few of the values that we use are base year values while others are projected inputs. And the base year values include the current vehicle stock, the current household-type distribution, current fuel consumption, and current vehicle miles traveled or VMT. And then we have projected inputs which are future economic and demographic data which come from Moody's and the Department of Finance future energy prices from the EIA, future vehicle attributes which are compiled by a contractor as well as through staff input and future transit and school bus population. And these inputs go through 2030 which is the end of our forecast.

And another important thing to note about our demand scenarios is that they are based on electricity demand. So the high -- the high demand forecast is our high electricity demand forecast which means that is the set of inputs that is most favorable for higher electricity consumption which would mean high population, high income, and then high petroleum fuel prices, but low electricity, natural gas, and hydrogen fuel prices. And this would also mean lower electric vehicle prices and relatively higher gasoline vehicle prices compared to the other cases.

We have the mid demand case which is the middle inputs for all of them. And then the low demand case which is the opposite of the high whereas population and income are low but electricity, fuel prices are high and petroleum fuel prices are still low.

And now I'm going to present our light-duty vehicle results.

COMMISSIONER MONAHAN: Can I -- I'm sorry, can I ask just a quick question?

MR. PALMERE: Uh-huh.

COMMISSIONER MONAHAN: Can I go back one slide?

MR. PALMERE: Yeah.

COMMISSIONER MONAHAN: Just so I understand since fuel prices are, you know, time specific at least for transportation, trying to do it off peak. Are you saying that the high price for the low demand, the high price would mean for transportation fuels, the price of electricity would be high?

MR. PALMERE: Yes, that's correct.

COMMISSIONER MONAHAN: Okay. So even if you're charging off peak, you're still assuming high price?

MR. PALMERE: So by high we mean high relative to the other cases.

COMMISSIONER MONAHAN: Uh-huh.

MR. PALMERE: So, it'll be like --

COMMISSIONER MONAHAN: Oh, so it's only like high relative to other cases, not high relative to electricity prices generally.

MR. PALMERE: Yeah, that's a good -- that's a good -- yeah, thank you for clarifying.

COMMISSIONER MONAHAN: Thank you.

MR. PALMERE: Yeah. These high, mid, and low means relative to the other scenarios.

And then here's another scenario chart, if you haven't had enough of these. There are -- obviously, these are all the inputs we use or a summary of the inputs we use. And I'm not going to go over it in great detail for the purposes of time but you can see if you can read that closely, you can see some of the different inputs we assume, for example, vehicle prices in our low case are based on a battery price declining to $120 per kilowatt hour, whereas in the high case, it's down to $80 per kilowatt hour.

And then we have an aggressive and bookend case that we -- we created as an experiment to see how high the EV population could grow. And in the bookend case, we have battery prices declining to $62 per kilowatt hour.

And then other important attributes are makes and models, model availability where we have more classes of PEVs, plug-in electric vehicles, available in the higher scenarios, higher ranges, higher fuel economy, and lower refueling time.

In addition, the incentives are forecast to last longer in the higher cases. Meaning that in -- through 2030 in the aggressive and bookend case, the state rebate will still be available as well as HOV lane access for PEVs and FCVs. Whereas in the low case, it expires as in 2025 for the rebate and 2021 for HOV lane access.

And then the last --

MR. RIDER: Mark, can I ask you a question about this table here?

MR. PALMERE: Yeah.

MR. RIDER: I'm not deft enough to remember. I've looked at this for the 2018 as well.

MR. PALMERE: Uh-huh.

MR. RIDER: Has any of these -- have any of these cells here been updated or changed since 2018?

MR. PALMERE: Yeah. A lot of the attribute ones have changed. The incentives and preferences are pretty much the same. But the attributes we have in the higher cases we have more availability in the -- or the aggressive and bookend case more availability in the fuel cell market.

MR. RIDER: Okay.

MR. PALMERE: I believe the ranges are a bit different. And I believe the vehicle prices are lower as well.

MR. RIDER: Great. Thank you.

VICE CHAIR SCOTT: Ken, one of the things the team is also working to do is to update the attributes as well. So one of the ones we've talked about is time to station. So if you're charging at home or at work, your time to station is sort of zero. Right? But right here, we're sort of captured it by the same way that it would take you to drive to a gasoline station which works with a fuel cell. Right? With the hydrogen, you've got to drive to the station still. But we might to tweak some of those additionally for charging infrastructure and where people might be charging.

And we've also worked really closely and maybe Mark I can let you or the team speak to this in more detail. But with the demand analysis working group has a specific group that's looking at the electrification of vehicles. So like some of the SCE scenarios which are much more aggressive than ours. You know, we've been working with SCE to try to roll those in as well to get a really good number within this space. But there are still things that we need to tweak as we go along.

COMMISSIONER MONAHAN: And the 2030 ZEV population, can you talk about how that was varied this year compared to last?

MR. PALMERE: Yes. Actually, there's a few slides with the population numbers so I'll be going over that very soon. And thank you for that.

And Commissioner Scott, going back to what you said. Yeah, we definitely use -- we definitely appreciate the input from the demand analysis working group because they are -- it is a number of utilities and a few OEMs as well who are able to provide their unique -- or different perspective which is very helpful.

And, you're right, with the -- with things like time to station and fuel prices, I know you have brought that up in the past the off peak charging. Things like that. It's -- we're still figuring out ways to incorporate them into the forecast because electric vehicles definitely bring up a lot of new -- new ideas that weren't present in the -- that weren't even consideration in the forecast ten years ago before -- before the technology was prominent.

And now I'm going to go over the light-duty vehicle results. And to start with, this is the overall vehicle stock and it ranges from about 35 million to 35½ million in 2030. And you'll notice that's pretty similar, there's not that much range. And that's because the overall vehicle stock is a result of income and population changes. And the income and population numbers that we have are not too different. So as a result, the overall vehicle stock population is not going to be that different where we see a lot of the variation is the stock by fuel type which I'll be going over next.

And here's the plug-in electric vehicle stock which is not to be confused with the ZEV stock which is zero emission vehicles and includes hydrogen as well.

PEV does not include the fuel cell vehicles.

And in -- for PEVs, the number of PEVs by 2030 ranges from a little over 2½ million to a little under 4.5 million in the high case. Which means there is quite a bit of difference, depending on the attributes and inputs which means that right now that we can envision a wide range of possible scenarios where a PEV penetration could be higher or lower depending on what sorts of vehicle attributes are offered and what sort of policy and incentives are made to nudge it in one direction or the other.

And then this graph looks very similar. It's just with the hydrogen vehicles added in because this is ZEV stock as opposed to PEV stock. And I'm going to look at the hydrogen numbers more specifically later. But in general, it's still about between 2½ and 4½ million ZEVs in 2030.

And this is just the low, mid, and high case. For this presentation, we didn't include the aggressive or bookend but as shown in that table, they are higher.

And compared to the preliminary forecast, this is -- the BEV and the PHEV numbers are pretty similar. We see a little bit of -- a little bit of an increase but overall, they're very similar to what we had in the preliminary workshop in July I believe it was, and this was because we didn’t have a lot of changes to our attributes or to any of the baser -- baser numbers in those few months.

And this is just more specifically battery electric vehicles. And battery electric vehicles of all the ZEVs, they’re the ones that we’re forecasting to have the biggest jump in 2030. In the high case, they make up about 10 percent of total vehicle stock. Just a little bit under -- a little bit under 3 million. And in the low case, about 1.7 million.

So again, we’re seeing that wide variation depending on the attributes and depending on the case.

PHEVs also rise but not quite at the level that ZEVs arise, but still we see about a four or fivefold increase from currently as high as 1.4 million in the -- in 2030 in the high case.

And something to notice in both of these charts is you’ll notice the -- at 2025, there’s a little bit of a kink in each of the lines. And that is due to in our forecast, we anticipate the state rebate running out in 2025, that’s just -- obviously we don’t know that but that’s just our best guess based on what we do know. And so you can see the results of that in the -- in the graph where it does have an effect on stock and it decreases the rate at which BEVs and PHEVs are put on the road.

And just one more draft about BEVs and PHEVs is the breakdown between BEVs and PHEVs. This is something that we've seen in the past a lot more optimism for PHEVs. But now based on what we have with some of the announcements of manufacturers discontinuing, some of the popular PHEVs and more focused on BEV technology, that we're anticipating right now it's about a little over 50 percent the share of BEVs verses PHEVs, we're anticipating it to be almost two-thirds the ratio of BEVs to PHEVs in 2030 in the mid case.

And that is as a result there's a lot of different attributes, obviously the prices and all of that is going to have an impact. But overall, we've seen manufacturers tend to focus more on BEVs based on their announcements and other plans. So that's why we have a more optimistic future for BEVs. Although, as you saw in the last graph, PHEVs are still increasing on a steady rate.

And finally, this is going to be my last slide, I believe. And this is the fuel cell vehicle stock. And before I get to that, I want to mention that we do forecast all fuel types so we do have graphs like this for all of the fuel types currently on the road, including gasoline, diesel, flex fuel hybrid. And for the purposes of time, I'm not going to present them, but they are in the appendix of this sheet if you have this, so you can take look at your convenience or -- and we're happy to answer any questions about that. But for the purpose of time, we're focusing on ZEVs.

And the final one I'm talking about is fuel cell electric vehicles, hydrogen vehicles. And this is where we did see a significant difference between our preliminary forecast and our revised forecast. Our revised forecast has about 160,000 hydrogen vehicles in 2030 in the mid case. And that's about a 30,000 increase from our preliminary forecast. And that's due to just better -- or having more actual data from the DMV as -- since hydrogen is the newest technology that we're focused on. It changes even more quickly than BEV and PHEV and our 2018 actual numbers that we were able to finalize indicated a more -- more optimistic future for fuel cell vehicles. So that's why you see if you compare this to the preliminary graph, that's why you see that increase.

And I just want to talk about how in this one, the low is noticeably lower. And that's because as I say, it is a little bit of a newer technology so we really have no idea if it's going to catch on or if so, how much. And that's why in the low case, it's not very optimistic at all for it just because there's a chance that the prices could never go down and it just never breaks out and becomes a common technology. But in the mid case and the high case, it is a lot more optimistic over close to 200,000 on the road in the high case.

And so that's the end of the light-duty vehicles. If there are any questions, I'm happy to answer them from --

COMMISSIONER MONAHAN: I have maybe more of a comment than a question which is I think it would be worth on the charts showing the aggressive scenario just because if we, you know, that -- that puts us closer to where we need to get to meet our state goals.

MR. PALMERE: Uh-huh.

COMMISSIONER MONAHAN: And it highlights to the state that in order to reach that, we're going to have to do some pretty aggressive measures.

And so I do feel like it's important to show how we are all working together to meet the state goals and how much work it's going to take. Not just us, right? But the entire state to be able to meet those goals.

So that's just a comment.

And can you go back to the fuel cell slide? I mean, this is the one I was the most surprised by because, you know, we have 6,500 today on the road, we only have a few manufacturers that are producing them.

They have plans to ramp up but other manufacturers are not. It takes a long time to scale up fuel cells.

I'm just very skeptical that -- yeah, the mid and high cases don't seem to align with where the market is today. It might be where the market is in 2025, we might start getting that trajectory but I don't see that happening right now.

So, yeah, that's my concern is that the battery electric ones to me seem, you know, more aligned with where we're seeing the market. The fuel cell one does not seem very aligned with right now where the market is. It's where we hope the market will be in a few years.

MR. PALMERE: Uh-huh. Yeah. Yeah, that's definitely a fair concern as I mentioned the fuel cell is the one that we're the most uncertain about.

But just comparing -- looking at the numbers now as you said 6,000 to even as recently as twenty -- 2016 or 2017, when it was still under 1,000, we are seeing the growth. And yeah, as you mentioned without -- without a lot of manufacturers, it's going to be hard --

COMMISSIONER MONAHAN: The models.

MR. PALMERE: -- but we have seen -- yeah.

COMMISSIONER MONAHAN: Yeah. I mean, we have a very limited number of models, we have a very limited number of manufacturers.

And our hope is that we'll be able to build from that and scale up rapidly. It's just --

MR. PALMERE: Uh-huh.

COMMISSIONER MONAHAN: It's not going to happen by next year.

MR. RIDER: Yeah. Right. That's like a four times, if we're at 6,000 now just looking at this graph. It's almost a four -- I mean, you'd have to get to like over 20,000 next year and the next year.

MR. PALMERE: Yeah.

VICE CHAIR SCOTT: I think it's worthwhile. I mean, one of the things the transportation team does with the Air Resources Board is there's a report that comes out in June about how many cars are on the road. And a report that comes out in December about how many -- how many fuel cell cars are on the road. And then a report comes out in December about how many hydrogen stations there are and what are the things that we need to do to keep moving. And I do think these early year numbers in the mid case align with those reports from Air Resources Board where they've talked to the manufacturers about what they see coming.

But it would be worth digging into to make sure that -- that those reports that we're putting out match up with what we have here in our demand forecast as well.

And it's been a little while since I've looked into it so I can't remember what the exact numbers are but I do think those early year numbers are -- are matching up.

COMMISSIONER MONAHAN: With the AB 8 report?

VICE CHAIR SCOTT: Yeah. But we should double check because it's awhile since I looked at it.

COMMISSIONER MONAHAN: Yeah. And the AB 8 report was also talking about how by 2025 there seems to be a lack of fuel cell models that are going to be able to make the -- make the market really scale up.

And we've had these supply disruptions which have, you know, for folks who want to lease these vehicles, there's a lot of uncertainty about whether they'll be able to get the hydrogen fuel even as we're making a lot of progress on the hydrogen stations. So just --

VICE CHAIR SCOTT: Think about how we portray that, huh?

COMMISSIONER MONAHAN: Yeah. Yeah.

VICE CHAIR SCOTT: Absolutely.

COMMISSIONER MONAHAN: Yeah. It's important to highlight that they are -- they have the potential to scale up and they have the potential to do it, but we have to also face the market realities which are where we are today.

MR. PALMERE: Uh-huh. Yeah, definitely for sure. Thank you for -- thank you for that input.

Commissioner Monahan, and going back to your previous point, the aggressive is that's definitely something we can include on our charts as well. We try to keep it a little bit -- try to not, like, overwhelm people with too many lines but that's definitely, for going with your point, that's definitely something that we can do for that purpose. So thank you.

Now I'm going to say I'm going to hand it over to Bob McBride on medium and heavy-duty vehicles.

MR. MCBRIDE: Good morning, Commissioners, stakeholders, all the participants.

Just a second here. Now we turn to medium and heavy-vehicle forecast. We include field technologies in each class once they're commercialized, meaning offered for sale by dealer. Often a driven-incentive program so no medium-duty hydrogen and no interstate long haul ZEVs. Gasoline and diesel hybrids announced by manufacturers using these technologies in other classes are included. Some terminology that's specific to medium and heavy.

ZEVs are, when I use ZEV, it really means zero emission despite there will be a credit system in advance clean trucks, but we're not going to delve into that.

It’s a proposed regulation.

So ZEVs, battery, electric, hydrogen fuel cell catenary electric. Then there’s NZEV, near ZEV, that’s plug-in hybrids, essentially, which may eventually emerge into general trucking but there’s none that are commercialized now outside the very small world of vocational trucks like bucket trucks, called -- which are also called power takeoff, cranes, that sort of thing. They’re not in general trucking.

Once we walk through the vehicle weight classes, I’ll talk through our summary table, the forecast scenarios, yet you need one more of those. We have a brief look at ZEV buses in 2030 and then turn to the truck forecast. I’ll describe the incentives used in the truck choice model and then focus on tractor trailers, cost per mile, and market share for the tractor trailers, for the in-state tractor trailers. Manufacturer announcements and a fleet price for hydrogen. The medium and heavy-duty ZEV forecast slide then Aniss Bahrenian will share results on fuel consumption.

Here's our medium and heavy duty -- here, medium and heavy duty means on road trucks and buses, the gross weight of 10,000 pounds and over. Gross weight is the maximum loaded weight that’s legal rather than the unladen or the curb weight of the vehicle which is quite a bit less. The heaviest here is eight times the weight of the lightest which is quite diverse by weight alone, not to even talking vocation. They're also diverse in their applications. Cargo and passengers, freight versus services, specialty vocational vehicles like cement and bucket trucks.

We included our matrix with the eight truck classes we use and which fuels they appear -- or which fuels appear in each class. It's in the appendix. We're not going to go through that right now.

So here's a pocket guide to the truck scenarios in the entire medium and heavy-duty forecast. Three scenarios are considered for trucks and for transit buses, low, mid, and high. We apply the in-place regulations in the forecast such as innovative clean tracks -- innovative clean transit and the existing truck rules. Existing statewide truck rules, I should say.

Our modeled truck incentives take a range of values over time largely for ZEV and low knocks technologies. The air resources for HVIP program, hybrid and electric vehicle incentive program or something very close to that, for commercialized vehicles through CALSTART which vary in how far they extend in the future, how much of the cost is covered. So the incentives are different in the three cases.

The three cases also have distinct forecasts as to battery prices. More on incentives and batteries later. Our scenarios for forecasts stock of different ZEVs is on the last four lines, including lines for battery electric hydrogen, fuel cell electric, and catenary electric. At least you can get there. They're specific. That changed quite a bit.

ZEV stock in 2030 varies by a rough factor ten between low and high cases so that illustrates the uncertainty in this really rapidly developing sector.

Here's a 2030 snapshot of ZEV stock in three truck classes. Innovative clean transit regs require ZEV drive trains in new vehicles in increasing percentages from 2023 and 2026 to a hundred percent in 2029.

Airport shuttle regulations require 33 percent ZEV in fleets by 2027 and a hundred percent somewhere in the '30s. And note that the shuttles number -- okay, that's the correct number, 789 of those airport shuttles.

We expect a good population of battery electric school buses given support from public funding. Almost 4,000 transit buses, over 700 shuttles, 2300 school buses.

Wait, this is déjà vu, why do we have this? Oh, truck forecast is separate. Okay.

VICE CHAIR SCOTT: Bob, can I ask a quick question about that back on page 19?

So you said it was -- it's the 33 percent reg that the Air Resources Board has recently done. Is that 33 percent of today's population or that's 33 percent of the population that you think will be on the road in 2030?

MR. MCBRIDE: The 30 per -- no, 30 per -- which sector are you talking, Commissioner?

VICE CHAIR SCOTT: So you were mentioning the airport shuttles, right, and you said it --

MR. MCBRIDE: Yeah.

VICE CHAIR SCOTT: -- requires 33 percent of them to be on the road by 2027 have to be ZEVs, right?

So my question is, are you basing your number off of how many there are today or how many airport shuttles you think there will be on the road in 2027?

MR. MCBRIDE: I'm pretty --

VICE CHAIR SCOTT: If that makes sense.

MR. MCBRIDE: I'm pretty -- let's, Elena Giyenko actually prepared the --

VICE CHAIR SCOTT: Okay.

MR. MCBRIDE: -- these slides.

MS. GIYENKO: Yeah, so, you're correct. This directly from the regulation.

VICE CHAIR SCOTT: Uh-huh.

MS. GIYENKO: So the numbers, I believe in 2030, there are close to 60 percent. So this number currently, I think -- I believe in February Air Resources Board surveyed airport shuttle operators. They received I believe roughly a thousand buses that are currently in operation. However, they don't have any actual data. The airport shuttle regulation will come into effect with the reporting starting 2022.

VICE CHAIR SCOTT: Uh-huh.

MS. GIYENKO: So we would know exactly how many buses are on the road --

VICE CHAIR SCOTT: Okay.

MS. GIYENKO: -- directly.

MR. MCBRIDE: Thanks, Elena.

We're on 21. So there are a number of changes from the preliminary forecast. I was just happy to have a preliminary forecast, but it needed a number of tweaks because ZEV numbers were quite low. So we make changes in data and some assumptions since the -- for these, I'll look at here.

We lowered the embedded battery prices in our battery electric trucks to 30 percent higher than what we used in the light-duty forecast. That's based on an estimate of how much you have to beef up medium and heavy-duty battery. Still quite a bit lower than we had in the preliminary. Thirty percent may cover cost of cooling, control, and system control. Power rating since medium and heavy-duty trucks have intense drive cycles.

When a hypothetical fleet considers how many miles a truck will go a year, we now include only the four recent vintages. So we're looking at 2014 to 2017 instead of ten years in the preliminary forecast which I believe looked back to 2009.

Truck requirement -- I'm sorry, truck retirement is as important in new truck choice in future purchases. So drilled down a little bit. We now use three cases for truck retirement based on data from two historical periods on record and EMFAC data. And their midpoint is mid case.

We now use a hydrogen price assuming fleet ownership of a right sized hydrogen station and lower tank pressure -- or lower as compared to light duty. When taken together, these result in a far lower price than our retail hydrogen price we use for light duty.

The premium to purchase -- to the purchase price of alternative fuel vehicle beyond the cost of the same vehicle conventionally fueled, that price we call incremental cost. So it's an incrementing cost, yeah. From recent hybrid and electric vehicle incentive program records, we determined the fraction of incremental cost covered by vouchers for each truck class and each incentivized fuel technology. So they varied both by class and by which fuel they were.

I applied this fraction to estimates of purchase price through 2021, for all three scenarios. So the three incentive scenarios and the three incremental costs are the same through 2021. Funding is assumed to be available for all comers which may be a shady assumption. Starting in 2022, the low scenario gets no incentives. The mid scenario gets 80 percent of the current fraction of incremental cost. So high case, full incentive. Mid case, 80 percent. And the low case gets zero. So after 2021, there's no incentives in the low case which you'll see in the results a lot.

Now the high scenario actually gets 99 percent. And that's -- it would be 100 except it's a quirk of the model we're using. It blows up if you put in 100 percent. You can't have anything as cheap as the base fuel. So we assume this last one percent has negligible impact. The current truck choice model needs a net to be different.

So three scenarios, three incentive levels, funding available to all comers. So here's a look at one truck class. Market share, high scenario for fuel tech in Class 3 which is just bigger than light duty where the larger -- largest pickups and vans show up. Diesel dominates early and dips under 50 percent in 2025. Battery electric tops 30 percent in 2026 and has a slight decline later. And gasoline hybrid which is new in this class rises after 2025 reaches 20 percent in 2030. So --

MR. RIDER: Can you back to that slide? Quick --

MR. MCBRIDE: Certainly.

MR. RIDER: -- question on that. So this is the high demand case?

MR. MCBRIDE: Yeah, actually I looked last night. The mid case is pretty similar.

MR. RIDER: Okay.

MR. MCBRIDE: A little lower.

MR. RIDER: So this is -- just to go back to the voucher thing, is that -- those vouchers aren't for this type of vehicle or is that for this type of vehicle?

MR. MCBRIDE: Yeah, Class 3 does get a voucher. It's -- it's -- all the pickups are excluded first so it's -- actually, applies to a smaller population. I have not done this.

MR. RIDER: Okay, because I'm just --

MR. MCBRIDE: I'm just --

MR. RIDER: -- wondering if this is, I guess, is this y-axis here the percent of new cells for the --

MR. MCBRIDE: I'm sorry, yes, that's -- that's the market share, yeah.

MR. RIDER: Okay. So I mean, I'm just a little confused because if the voucher if the high demand case is essentially free in terms of purchase cost, one percent more, I guess.

MR. MCBRIDE: Free.

MR. RIDER: Essentially free and, you know, fuel cost is lower, why would anyone buy, I guess, like what's driving the diesel consumption?

MR. MCBRIDE: Well, familiarity for one. But really the core of --

MR. RIDER: But the (indiscernible). I mean, how does the model react to that?

MR. MCBRIDE: Yeah, the core of this truck choice model has adoption curves built into it. It's assumed, you know, pattern of innovation, diffusion, it's a logistic curve. So you're seeing that in the early years there. The later decline in electric, I think, I haven't tested, but it looks like it's due to the hybrids coming on.

MR. RIDER: Okay. Thank you.

MR. MCBRIDE: So in this slide, the large blue bar shows the in-state tractor trailers and it's labeled GVWR, gross vehicle weight rating 8, Class 8, combo, which is combination, meaning you've heard trailer on a tractor as opposed to having a single unit. So this one class uses more California fuel by far than other classes. It might even in total, I didn't do that sum.

The interstate tractor trailers to their right in blue consume a similar amount but shown here is the portion pumped in California. So the remainder fueling in other states where diesel's often cheaper.

Shown in red are the various straight truck classes. It's proposed advanced clean trucks regulation will require manufacturers to produce at least 50 percent ZEV and near ZEV PHEVs by 2030. And actually the Class 3 on the left, it's actually slightly lower. There's another multiplier that goes into advanced clean trucks, so their requirement for Class 3 is a bit lower than others. So because the tractor trailer dominates other classes and because no models to these things as ZEV or near ZEV are yet commercialized, we now examine this class in a little more detail.

When I was four, I was a four year old, I remember being able to recognize the make and model of every car by its front grill which entertained my dad and his friends. That's out the window here. The Tesla on the lower left and the Aeos, a California startup, upper right, look like the vehicle from Sleeper. The Nikola prototype is the only one that actually looks like a truck. The upper left, this is a Cummins prototype battery electric. I think this body looks like one of those low slung Disneyland people movers. The fuel is different and the manufacturers want to make the look different as well.

So the fuel cost per mile here for mid case and high case for the in-state tractor trailers, it looks quite similar. It's a slight shift downward for the alternative fuels in the high as opposed to the mid. The one dramatic difference is the diesel price. Closer to electric in the mid case and closer to hydrogen in the high case. We'll come back to this.

Small diversion. Alternative fuels are easier to implement when trucks return to a home base every day or take predictable routes hauling for a single shipper such as Wal-Mart, FedEx, UPS, Budweiser, on long haul, or medium hauls, regional even. These fixed route fleets are called dedicated fleets since they aren't dispatched to an unpredictable origin and destination. As you might imagine, the fraction the tractor trailer fleets that operate locally, regionally, are on dedicated routes. It's the ceiling on alternative fuel adoption at least by 2030.

In this table from a report by SJ Consulting Group, the percentage of the dedicated hauls moved from

35 percent in 2017, 39 percent in 2018. Whether these fleets are representative of all fleets or the change from ’17 to ’18 is a permanent trend is yet to be seen, but the takeaway is that something on the order of a third to two-fifths of hauls are on dedicated routes. This portion of long haul goods movement by trucks lends itself to ZEV trucks or near ZEV trucks as opposed to the relatively intractable dispatched trucks that go who knows where.

So here we see the market share of trucks for fuel in this class, in-state tractor trailers for mid and high scenarios. Now one thing about this class, we lumped together port trucks, regionally hauling, and a certain amount of in-state longer hauls, things that go up and down 5.

So anyway, diesel share. The black line decreased in both of these, but in the high it reaches less than half of the mid case share by 2030. For both scenarios, battery electric reaches about 30 percent share, but in the high case, hydrogen also reaches something like 27 percent in 2030. That’s the green line.

Recalling our incentives, 99 percent of the incremental costs, hundred percent of the incremental cost is incentivized in the high scenario. So the biggest influence of market share in this model is the cost per mile, so the fuel cost and the fuel economy.

Returning to the cost per mile, Slide 28 says here --

MR. RIDER: Question on this graph here.

The direct -- what is direct electric? I don't understand this.

MR. MCBRIDE: Okay, very good. Good observation.

Now in 2014, Energy Commission published a report on catenary electric trucks that would be applicable in places like hauling from the ports to the railyards. These look like the San Francisco Muni buses, they have a line overhead. And in those particular regions, I don't think there's much of a NIMBY concern.

So and they make a little bit of economic sense. Their share is pretty low mostly because we've constrained the population of trucks that it applies to. So it's really, you're looking at that's a fraction of the port trucks. And that is a good observation. So.

COMMISSIONER MONAHAN: One second. Can we stick with this one for a second?

So the truck market share in-state tractor trailer, what share of total VMT is that? Or do you have a sense of like of all the VMT of heavy-duty, what share is this that we're looking at?

MR. MCBRIDE: I can -- I can easily get that. I don't --

COMMISSIONER MONAHAN: Okay.

MR. MCBRIDE: -- have it here. But the fuel consumption here, assuming that your interstate blue bar is going to be higher, that fairly representative of VMT and fuel economy.

Now these things are bigger but they tend to have pretty good fuel economy considering their size. So, yeah, there's a lot of miles. This is a very important sector.

COMMISSIONER MONAHAN: And so can we go back to the next -- keep going, there, no, the next one.

MR. MCBIDE: Oh, okay, there you go.

COMMISSIONER MONAHAN: There you go.

MR. MCBRIDE: Okay.

COMMISSIONER MONAHAN: So -- so this is a pretty high percentage of -- in the high case and even in the mid case, the mid case looks like it's 30 percent. Is that -- I'm having a hard time seeing the electric share. In the high case, it's a little more than 30 percent. That's a lot of -- do we -- how many vehicles is that?

MR. MCBRIDE: I'm going to have to get back to you. I'm not --

COMMISSIONER MONAHAN: Okay. Sorry. I just sort of ask all these -- it’s just that it’s -- it’s high. Higher than I would have guessed.

MR. MCBRIDE: Well for one -- one mitigating thing is that the interstate trucks are not included here. So --

COMMISSIONER MONAHAN: Right.

MR. MCBRIDE: -- a lot of what you see are those.

COMMISSIONER MONAHAN: It’s only intrastate trucks.

MR. MCBRIDE: Yeah. So and some of the populations like the port trucks are very concentrated. You might never normally seem them.

COMMISSIONER MONAHAN: Uh-huh.

MR. MCBRIDE: So I don’t know. This is -- this is a particular truck choice model --

COMMISSIONER MONAHAN: Uh-huh.

MR. MCBRIDE: -- and this is where it went. And --

COMMISSIONER MONAHAN: Yeah.

MR. MCBRIDE: -- I think it’s not out of line with -- with the numbers we put in anyway.

COMMISSIONER MONAHAN: Uh-huh.

MR. MCBRIDE: So I wanted to look back at the cost per mile for a second. I see the high with diesel and hydrogen are in the same neighborhood in the forecast. That's -- those two lines, that's enough to give hydrogen some umph in the high case, even though the price is still a bit higher than diesel.

Next slide. So if your -- market share alone doesn't dictate the number of ZEVs or near ZEVs. Economic growth in the aging and turnover fleets and some other factors drive the number of new trucks purchased in total of all fuel types.

Here we see a low in the second half of the forecast, maybe 58,000 trucks a year and up to 73,000-ish in the high. Suppose market share of 50 percent ZEV in that high case. It's actually a little bit higher according to these numbers. That's around 36,000 for the high scenario between battery electric hydrogen fuel cell, catenary electric. And, again, we're not including, we haven't included plug-in hybrids and general trucking for truck choice. Mostly because none are commercial.

So any case, this is -- this is the size of the, of the pond that is divided up by different fuel types. So tiny bit of fun.

Introduction to the Volvo VNR Electric models, this -- the interesting paint job on the right. Part of a partnership called LIGHTS, Low Impact Green Heavy Transport Solutions between Volvo truck and the South

Coast Air District. This demonstration fleet will be studied carefully, you know, and improve the second generation of these guys. The smaller Class 6 freightliner M2 on the left, well actually in the middle, also has a similar demonstration fleet, it was delivered to Penske in December last year.

The white freightliner eCascadia, you notice that's a sleeper cab. It's one of a handful of trucks that's tooling around the northwest somewhere. They're not actually in California as I'm aware.

So we did test the price – prices announced by manufacturers for the Tesla semi and for the Nikola 2 tractor trailers that we think might fit nicely in our in-state tractor trailer sector. Both achieved sufficient market shares to get large production runs or what's considered a large run for medium and heavy. But since there are no commercialized ZEV tractor trailers delivered to date at a known price, uncertainty over the ability to produce these trucks at the announced prices over a period of years sort of muddies our Magic 8-ball.

So for the in-state tractor trailers, we turn to our component based bottom up price attribute for modeling market share. Regardless, in the high and mid cases, 99 percent or 80 percent of the incremental cost is incentivized anyway.

So retail hydrogen prices are simply too high for commercial trucking. And most stations built today can't accommodate the heavy duty trucks in any case. The high price is cost by expensive, underutilized capacity as a retail stations and by the high cost of compressing that additional 5,000 PSI up to 10,000 for light-duty vehicles. However, if our homebased and dedicated fleets can be built, paired with electric hydrogen production and dispensing station sized exactly to meet the needs of that fleet, higher utilization can drive down the cost of hydrogen. Also heavy- duty truck hydrogen tanks pressure at 5,000, they can be a bit larger than you can fit in a light-duty vehicle. So they can also save.

According to the California hydrogen fuel cell partnership, these factors support hydrogen priced from $5 to $7 a kilogram, but we've seen more optimistic prices from Blumberg and similar prices from other sources. Nikola plans for 2021 include a fleet and a station for Anheuser-Busch in Southern California. So we'll see if these announced prices are going to work.

So here's some medium and heavy-duty ZEV truck and bus forecast. The low scenario's mostly buses as trucks barely take off due to high electricity and low petroleum fuel prices. No incentives after 2021. The mid scenario reaches 78,000 total ZEVs in 2030 and the high reaches about 120,000 in 2030. Actually a hundred -- okay, about 120,000 in 2030.

So thank you. We now turn to Aniss Bahrenian for the fuel consumption forecast. Any questions? From the dais questions, otherwise? Thanks.

MS. PETERSON: Just -- can I make a quick, just a quick comment?

It would be helpful to see the breakout of fuel cell to BEV in the forecast. Not just have it be ZEV stock forecast, but broken out by the fuel type, just.

MR. MCBRIDE: Sure. Absolutely. There are a lot of ways to slice it. The data's there.

MS. PETERSON: Okay.

MR. MCBRIDE: So not a problem.

MS. PETERSON: Yeah, I'd love to be able to see that.

MR. MCBRIDE: Okay. Thank you.

MS. PETERSON: Thank you.

MS. BAHRENIAN: Good morning -- good afternoon now.

My name is Aniss Bahrenian and I'm presenting the total fuel consumption this afternoon.

It will be good to see the concentration of fuels in different sectors. It will help with looking at fuel consumption in the later slides. If you look at the bar charts here, we can see that about 89 percent of LDVs currently are gasoline. They used to be even higher, it has declined now. So the dominant fuel for light-duty vehicles is gasoline versus diesel which is a dominant fuel for medium and heavy-duty vehicles. So when we are -- when you look at the results for those two, then you can see which sector it is coming from.

This fuel consumption forecast, we are just marrying light-duty vehicles with the medium and heavy-duty vehicles as well as rail, so the total consumption is also going to reflect what is being consumed by the rail too. In some other forecast or future scenarios, you might see future scenarios that relate to on road vehicles and they exclude LDVs. We do -- and they exclude rail from those but we do include rail in this forecast as well. We do not include military or marine movements in our forecasts.

So light-duty vehicles are everything that is up to 10,000 pounds. This is -- this is gross vehicle weight. If you look at EPA or so that would be one source of difference between our forecast and others, is that EPA and CARB limit LDVs to 8500 pounds but we have up to 10,000 pounds. Medium and heavy-duty vehicles are more than 10,000 pounds and of course rail is rail.

And within the LDV, I should indicate that we have 15 different classes of vehicle and for the questions on some of the ZEVs for instance, we need to consider how many classes are introduced in each of these sectors, 15 classes of LDVs. In other words, we can generate a forecast for each of those 15 classes of vehicles. Our models are light-duty vehicle models actually substitute, they reflect the substitution between classes, not just substitution between field types. And that is important to know.

Now when it comes to light-duty vehicles and the fuels that we are incorporating in the forecast, the fuels that are choices for light-duty vehicles are gasoline, hybrid flex fuel vehicles, diesel, BEV, PHEV, FCV, and PH -- PHFCV, which is important to note here.

We are only –- the only forecast I think in the country probably that where we are forecasting plug-in, hybrid fuel cell vehicles. These vehicles do exist in Germany right now and Mercedes was planning to bring it to the U.S. market in 2019. I think they have delayed it now to 2020 or 2021.

So when you look at the high light-duty hydrogen vehicle forecast and there are a lot of questions about that, please keep in mind that we include two types of hydrogen vehicles. It is FCEV and plug-in hybrid FCV which are more attractive particularly in light of the limited station availability because people have the choice of either plugging it into electricity or just go to the hydrogen station and fuel it right there.

And another reason for the higher hydrogen forecast that you would see if our forecast that was more than you expected is that we also introduced them -- introduced different classes of vehicle. The more classes we introduce in the market, the more demand there is going to be. And so in the mid, low, and high scenarios we have different number of classes that are introduced in different times. That's one of the reasons why those are higher.

When it comes to medium and heavy-duty vehicles as Bob McBride mentioned, there are six different weight classes there between Class 3 and Class 8. And the fuels that we have listed here are not introduced for each of those six different classes of medium and heavy-duty vehicles. They are introduced in selected classes. For instance, hydrogen vehicles are introduced in the Class 8 only, not in the other classes. That is the tractor trailers.

But we do have gasoline, gasoline hybrid dedicated E85 where owners cannot put anything other than ethanol in their vehicle. This is in comparison to flex fuel vehicle when people have the choice of either fueling their vehicle with gasoline or with ethanol.

We also have diesel, diesel hybrid, battery electric buses and trucks. Direct electric which was the catenary buses, catenary buses and trucks. FCV, fuel cell vehicles. We don't PHFCV in the medium and heavy-duty vehicle category. We have CNG, LNG, and propane.

When it comes to rail, essentially here we have diesel and then we have direct electric which is essentially light rail that you see right across the street here. That is direct electric and that is rail so it is included in our forecast. If you go to Germany, in Germany they also have hydrogen rail. So you can also use hydrogen there, but we don't have it here in this state, and I'm not sure how much authority the State of California has over the rail to mandate use of hydrogen for rail.

So when you're adding everything up together, this is our high transportation fuel demand forecast by fuel type. You can see here again that the dominant fuels are still gasoline and diesel by 2030. But you do see that there is a decline and that there is an increase in alternative fuels here.

The increase in alternative fuels obviously drives down consumption of gasoline and diesel, but there is also another factor that results in decline of gasoline and that is increased fuel economy. That too is going to reduce consumption. In general, what we can say is that over time California is becoming more efficient so the fuel consumption would go down.

Now you couldn't really tell from the previous graph how much of the alternative fuels there was so for this one we are using only the 2030 consumption and we're showing the distribution between different alternative fuels. As you can see here for the pie chart on the left-hand side, these are alternative fuels by fuel type and you can clearly see that electricity rules the alternative fuels followed by natural gas which is for medium and heavy-duty vehicles.

And then hydrogen, which is the gray one, which goes both for light duty and heavy -- medium, heavy duty. Or actually, heavy duty only.

For the pie chart on the right-hand side, you can see electricity demand distribution by vehicle type. So we take the electricity part of the chart on the left-hand side and we divide it between light duty, medium, and heavy duty, and rail. As you can see here, the big chunk of electricity, transportation electricity comes from light-duty vehicles. A smaller portion of that is coming from medium and heavy-duty and even smaller portion from rail consumption. I think the distribution is about 86 percent for light duty, 10 percent for medium and heavy duty, and 4 percent for rail.

This is the revised transportation electricity demand by different scenarios. So in the previous graphs, you saw only the high case. This one shows low, mid, and high. Again, the kink here in these three curves reflects the fact that -- that incentives are being discontinued in 2025. If we had shown the graphs that included aggressive and high scenarios, you could see that in the aggressive and high scenarios, we definitely exceed the 5 million PEVs or ZEVs that Governor has mandated, or Governor has ordered.

But here, this is the low case. In the low case, we are exceeding the CARB's scoping plan over there. They have 4.2 million ZEVs, we have about 4.6 or 4.9 here actually. So we do exceed that but we don't quite reach 5 million in Governor's Executive Order.

In the high case, as you can see here, we have about 21,000 gigawatt hour. And going back to Cary Garcia's graph showing about 320,000 gigawatt hours of electricity consumption. Consumption to consumption, we are still going to be significantly lower than 10 percent.

Ten percent of the total consumption is transportation electricity and that is reflected here, but it is definitely higher than what we have at the present time. I think right now is maybe even 1 percent. Something between 1 or 2 percent now and we are going to get close to 10 percent but not quite there, in 2030.

This is the revised transportation hydrogen demand forecast. You can clearly see the mid and the low are lower than the high case. This reflects the fact that we don't have any hydrogen trucks. We don't have anything in the medium and heavy-duty sector in the mid case, but we do introduce that in the high case. Well I should say with the exception of the buses, the transit buses, some of them are hydrogen. But when it comes to trucks, we don't have any hydrogen trucks in the mid case.

MR. RIDER: May -- may I ask a question --

MS. BAHRENIAN: Yes. Sure.

MR. RIDER: -- about this?

So a lot of this production of hydrogen is expected to come from or could come from electricity. How -- so when you're talking about the previous slide, that's really electricity just to service battery electric and direct electric vehicles. But the transportation sector itself in some of these forecasts would have a higher, as a percentage of state consumption, would have a higher percentage than --

MS. BAHRENIAN: That's an excellent point. Thank you for making that point. Yes, a good portion of it is going to come from electrolysis, as you mentioned. So that should increase production of electricity but that increase in production is not reflected in the transportation forecast.

MR. RIDER: Oh, okay. All right. Thank you.

MS. BAHRENIAN: Thank you for that point.

We should also say that the lower prices that we mentioned before -- Bob McBride mentioned for the fleet prices, one of those fleet providers is Nikola and what -- the assumption that they are making or the plan, their business plan includes producing green hydrogen. And when you produce green hydrogen using solar energy and then using excess electricity at night at a much lower rate, price could reach the levels that Bob McBride did use. And that makes a difference in fleet adoption of hydrogen.

Now the next graph is going to show the transportation natural gas demand. This is -- this is almost exclusively medium and heavy-duty vehicles. So that includes everything from the garbage trucks, all the way to the trucks that are going to be tractor trailers that are going to be adopting natural gas. As well as transit buses that are currently using natural gas but gradually they're going to lose market to electric buses. So this shows our total natural gas demand forecast.

VICE CHAIR SCOTT: Aniss, a quick question on that.

MS. BAHRENIAN: Sure.

VICE CHAIR SCOTT: Is that -- is that all natural gas so sort of the renewable gas that folks have been talking about in addition to fossil gas? Or is it just fossil natural gas?

MS. BAHRENIAN: Thank you very much for that question. One of the things that we don't do in our forecast, we do not differentiate between renewables and nonrenewables. The only renewable that we do identify and we have a separate forecast is ethanol and that is the E85 which you're going to find later. But even the diesel consumption that we are forecasting, that includes renewable diesel as well as regular diesel.

Same thing is true here. This includes renewable hydrogen -- I'm sorry, renewable natural gas as well as nonrenewable natural gas.

MR. RIDER: Aniss, just quickly. On these, these aren't -- are these the same cases? So when you say low, medium, high here on the natural gas --

MS. BAHRENIAN: Uh-huh.

MR. RIDER: -- demand forecast, that's high for natural gas but, you know, if battery, the other forecast we were looking at were high in terms of that would drive electricity consumption.

MS. BAHRENIAN: Sure.

MR. RIDER: So what drives high and natural gas consumption is like almost, not necessarily but sometimes the opposite of what drives high electricity consumption.

So are these the same cases that we were looking at in the other forecast? Or are these separate forecasts for the natural gas?

MS. BAHRENIAN: Again, thanks for that question.

We are using, when we talk about the high demand here, we have all of the alternative fuels at lower prices, not just electricity. It's electricity, hydrogen, and natural gas.

MR. RIDER: Got it.

MS. BAHRENIAN: So natural gas has lower prices. So in this case, both natural gas and electricity have lower prices or both natural gas and electricity have the higher prices.

MR. RIDER: Got it.

MS. BAHRENIAN: So you would limit the substitution that way. If you have used different prices as you were suggesting, then there could be more of any one of these.

MR. RIDER: Okay, got it.

MS. BAHRENIAN: Thank you.

MR. RIDER: Thank you.

MS. BAHRENIAN: Any other questions?

All right. And here's the team. We have, as Commissioner McAllister mentioned, small but mighty team. January '18 Transportation and Energy Demand Forecast. It takes a lot of people to generate this. And I'm sure all of you know, use billions and billions of -- Jesse Gage actually was keeping track of how many billions of data you're using. And it is mind-numbing, actually.

Thank you very much. Any questions?

VICE CHAIR SCOTT: I asked mine as we went along.

Any other questions from the dais? All right.

Thank you very much.

MS. BAHRENIAN: Thank you.

VICE CHAIR SCOTT: So I think with that, now we are at 12:35. We'll take a little break for lunch.

Let's come back at 1:30, right at 1:30, and we will pick up with the Self-Generation and Storage presentation.

So see everyone at 1:30.

(Off the record at 12:35 p.m.)

(On the record at 1:34 p.m.)

MR. COLDWELL: Okay, everybody, we're going to pick back up here.

So starting this afternoon, we have Sudhakar Konala coming up to do two presentations, one on the -- the first one on behind the -- his behind-the-meter PV forecast, and then the second one Behind-the-Meter Storage.

So Sudhakar?

MR. KONALA: Okay. Good afternoon, Commissioners, stakeholders, and members of the public. I'm going to do two forecasts today, as Matt had mentioned. I'm going to start out with talking about the PV and self-generation forecast and, after that, talk a bit about energy storage.

So to get started with the PV forecast, okay, I just want to start off with a slide that I've had in previous presentations. But to anyone that might be new, it could get really confusing if this information isn't conveyed.

So for the forecast, we have three cases, the high, the low and the mid. These are electricity demand cases. But in terms of the PV forecast, it's actually kind of reversed. In the high electricity demand case, we're assuming low PV adoption. And in the low electricity demand case, we're assuming high PV adoption. So throughout this presentation, you'll see me using the terms low and high, I'm referring to the electricity demand cases, but PV adoption is actually going to be reversed, so just something to keep in mind.

Another slide that I've --

VICE CHAIR SCOTT: Really quick, I'm sorry to interrupt you on that. It's me over here.

MR. KONALA: Yeah.

VICE CHAIR SCOTT: The previous slide, I think, is excellent for explaining the high PV adoption versus low PV adoption.

And I wanted to make the suggestion, Matt, I guess to you, to the Transportation Team, if we could right the scenarios in this kind of same way so that it's really clear what we're talking about in each scenario? I think that would be really helpful.

MR. KONALA: Yeah.

VICE CHAIR SCOTT: So sorry to interrupt you on that but thank you.

MR. KONALA: Yeah. Here, I have very high-level overview of how the Energy Commission PV models work. Essentially, we take in a lot of different inputs. We consider historically statewide installed PV capacity. And then we consider economic and demographic data that Cary Garcia talked about, such as household growth and commercial floor space. And we also consider our fuel price forecasts, especially the electricity price forecasts. And then we also look at other system-level data for PV systems in terms of cost and performance and how the systems are installed and oriented. And we feed that into our models and we get a forecast of capacity for the entire state.

We run these in different models, depending on which sector, so we have the residential sector model, the commercial sector model, and then everything else. And the residential and commercial sector models actually predict PV penetration based on a calculated payback or bill savings.

Once we have behind-the-meter PV capacity, we then use that to forecast generation.

So just an overview of what's changed in the 2019 revised forecast.

We have new updated demographic and economic data. This includes households, commercial floor space, and, of course, a GSP deflator. In terms of households, we have higher growth in households compared to the preliminary forecasts across all of the scenarios. In general, for commercial floor space, we have a lower forecast compared to the preliminary forecast. And this is going to be reflected in the forecasts by sector for PV.

In addition, for the forecast of electricity rates, we generally have higher electricity rates than the preliminary forecast. And this is most evident in the 2018 to '21 period where rates are significantly higher than the preliminary forecast.

But before I move on to the forecast, I just wanted to do a recap of what we're seeing in terms of PV adoptions in 2019 year to date. So this is data that I pulled just last week when the data became available. It's installations in 2019 through September 30th of this year. And I'm comparing it to installations in 2018 through September 30th, so the first three quarters of both years.

And what we're seeing is we're seeing higher PV adoptions in the residential sector across the three different IOUs with significantly higher levels in San Diego's territory. And in the commercial sector, we're seeing lower adoption compared to 2018 and, in some cases, significantly lower.

Overall, the residential sector, since there's just so much more adoption in the residential sector than PV -- than the commercial sector, we tend to see that, overall, adoptions tend to mirror closer to what's happening in the residential sector.

So one of the questions that people might have is what's happening in the commercial sector? We don't have a great idea but it looks like it has to do with broader economic conditions, specifically, there seems to be a lot of uncertainty in the business sector. And so I've posted a snapshot of an article from the New York Times from early November which says that a lot of companies are cutting back in capital expenditures. This is due to uncertainty with the economy, maybe the trade wars, a multitude of conditions. But this decline in capital expenditures most likely is affecting the forecasts -- the adoption of PV in 2019 since solar projects are a capital expenditure to most companies.

COMMISSIONER MCALLISTER: Sudhakar, do you chalk that up to just having sharper pencils or less favorable rates or something like that --

MR. KONALA: No, the rates --

COMMISSIONER MCALLISTER: -- (indiscernible)?

MR. KONALA: -- the rates are actually more favorable, so this is happening despite the rates.

COMMISSIONER MCALLISTER: Interesting.

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: Okay. So, in general, the commercial rate that a net-metered commercial customer would face are more favorable for PV adoption than the residential, like a net-metered --

MR. KONALA: Well, I wasn't --
COMMISSIONER MCALLISTER: -- residential?
MR. KONALA: -- I wasn't comparing the residential versus the commercial, I was comparing versus the previous forecast. Sorry.
COMMISSIONER MCALLISTER: Oh. So I'm actually asking about the rates that commercial customers face and whether they're just having a harder time finding cost effectiveness for that investment decision that they would make on solar?
MR. KONALA: I'd have to compare it. I don't have the -- I'm not sure what the rates are for commercial versus residential in relation. I can look that up and come back. But overall I think it's just when businesses are uncertain about what's going to happen in the future, they just tend to hit the pause button because they want to see what's going to happen. I think that's --
COMMISSIONER MCALLISTER: Yeah.
MR. KONALA: -- essentially what's happening.
COMMISSIONER MCALLISTER: Yeah. It makes sense.
MR. KONALA: But that doesn't explain --
COMMISSIONER MCALLISTER: The demand charges. The demand charge, you know, the shift, you know, commercial rates are going to, you know, have an ongoing

demand charge on them.

MR. KONALA: Yeah. Yeah.

COMMISSIONER MCALLISTER: So, you know, they're having to offset only the energy fees, so it's a less cost effective. But --

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: -- I'd be interested in some insight from you and your team, just on the rate environment itself --

MR. KONALA: Okay.

COMMISSIONER MCALLISTER: -- for non-res.

MR. RIDER: And that doesn't explain, you know, the different between Northern California and Southern California.

MR. KONALA: Yeah. Exactly.

MR. RIDER: It's a huge difference. I mean, all those factors that you mentioned here are global --

MR. KONALA: Yeah.

MR. RIDER: -- right? And there's a huge -- I mean, like -- and these are real numbers; right? These aren't forecasts?

MR. KONALA: These are real numbers, yes.

MR. RIDER: So, I mean, there's something further to be digging. Do you have -- is there a working -- or is there any initial information that would help tease out what the north versus south trends --

MR. KONALA: Well --

MR. RIDER: What's causing that?

MR. KONALA: -- in terms of north versus trend, we're seeing a lot of commercial adoption in the Central Valley, actually, and that largely falls into PG&E's territory, so that's what making the north look higher.

So the final point I wanted to point out is the Federal Investment Tax Credit for solar starts to decline. So 2019 is the last year we have the full federal tax credit at 30 percent. Next year, it declines to 26 percent. And then in 2021, it declines to 22 percent. And then starting in 2022, it goes away completely for the residential sector but is maintained at a 10 percent rate in the commercial and utility-scale sector.

Okay, so now, just to get into the forecast, here is a chart showing historical self-generation in the state, and also the forecast. So I have both -- I've separated it by behind-the-meter PV and all other technologies. So the other technologies includes large-scale industrial co-generation. It's not utility-scale, though, it's still behind-the-meter, but most of it is industrial co-gen. But you also have behind-the-meter wind, some fuel cells, and some other technologies, like microturbines.

So in 2018, in terms of the non-PV self-gen, we estimate about 14,000 gigawatt hours was generated, compared to 13,800 gigawatt hours for the PV. In 2019, PV went up to over 16,000 gigawatt hours. And by 2030, we expect PV to go up to 40,000 gigawatt hours, and this is just the mid case that I'm showing here.

So in terms of installed statewide capacity, in 2018 there was about 8,100 megawatts of installed PV capacity. We expect that to increase between 20,000 and 27,000, between the different cases, by 2030 with about 23,000 in the mid case.

Overall, the revised forecast is pretty much similar to the preliminary forecast but, as you can see, we have a slightly faster adoption happening in the first half of the forecast period and slightly slower adoption happening in the second half. This is --

COMMISSIONER MCALLISTER: Sudhakar, it would be helpful to have that green bit, the solar, separated out in a res and non-res.

MR. KONALA: Okay.

COMMISSIONER MCALLISTER: Yeah?

MR. KONALA: Yeah. Okay.

So in terms of the faster growth in the first half of the forecast period, it's generally due to a forecast of higher rates, both in the residential and the commercial sectors. So I do have a forecast by res and non-res, but for the individual utility service area forecast, not for statewide.

Also, I just want to briefly talk about the contribution of the Title 24 Standards in this year's forecast. So starting next year the standards require that PV be installed on new homes. So in the 2019 forecast, we've incorporated these standards into the baseline PV forecast. Previously, we accounted for them as the additional achievable AVR/AAPV forecast. But I'm going to restate past PV forecasts to include AAPV so it's a direct apples-to-apples comparison.

So just a review. PV adoption in new homes is now, essentially, a forecast of regulatory compliance with these standards. And the AAPV is directly going to be correlated to forecasts of new home construction. So if the forecast of new home construction changes between forecasts the adoption of PV, due to the standards, is also going to reflect that change.

For the most part the assumptions are the same as previous AAPV forecasts, so the expected level of compliance is 90 percent in the low case, 80 percent in the mid case, and 70 percent in the high case. And the average PV system size for new homes remains the same, although the average system size is different depending on the different planning areas and household size, so it’s different between different planning areas and different household sizes but it’s the same between different forecasts, so none of the information has actually changed from the previous forecast.

Finally, I have a chart summarizing the contribution of AAPV in terms of capacity between the last three forecasts. So in the 2019 revised forecast the contribution from AAPV is higher than the preliminary 2019 forecast, and also the 2018 update. And this is generally due to a higher forecast of new household growth in the 2019 revised forecast.

MR. RIDER: In this table, is this backwards on the demand? Because wouldn’t you get more capacity in the low demand?

MR. KONALA: No. So this is where the definitions of the scenarios is kind of confusing.

MR. RIDER: Okay.

MR. KONALA: So earlier I had stated that in the high demand case, you expect low PV adoption. But in the high demand case, we’re also assuming higher household growth and more new home construction. So the AAPV is kind of going to be higher in the high case.

So the AAPV is kind of counter to the overall PV forecast. And the affect it has, it narrows the range of the PV forecast. So thank you for pointing that out actually. Okay.

So that is the general overview of the statewide forecast. I'm going to go through each individual planning area really quickly.

COMMISSIONER MONAHAN: I have like the most basic question in the world. Feel free to mock me.

So can you go back to the 2019 revised PV forecast?

MR. KONALA: Uh-huh.

COMMISSIONER MONAHAN: Can you explain, why is the installed capacity highest in the low electricity demand scenario?

MR. KONALA: It's -- so it's how we define the scenarios. In the low electricity demand scenario, we have the highest level of PV penetration. That's just how we can get the lowest electricity demand. So, yeah, it was my first slide.

COMMISSIONER MONAHAN: I missed the first slide. I wasn't here for the first slide, so how I've been educated. Thank you.

MR. KONALA: Okay.

COMMISSIONER MONAHAN: Thanks for not mocking me, too, but --

MR. KONALA: No. I present this and I get confused sometimes, so that first slide is there to keep myself straight, as well, so I completely understand.

VICE CHAIR SCOTT: While we're on slide seven, just another thing that I really like about this slide, how you have your numbers here. So in 26, 700, for example, up at the top bubble, I think it's handy to have those numbers. On the previous slides we've had up until now, we're sort eyeballing where we think that number is. And so I think if we can update the slides, at least in the report, so that they look like this, that would be fantastic.

MR. KONALA: Okay.

VICE CHAIR SCOTT: That was not specific to yours but --

MR. KONALA: Well, thank you.

So moving on to the planning area forecasts, I'm going to just give a general overview of the forecasts. There's a lot of numbers here. And stakeholders and members of the public are welcome to dig into it and just contact me if they have more questions. But I don't want to get too much into numbers because I don't want to bore everyone with it.

So for PG&E, we forecast the energy generated to grow to about 19,000 gigawatt hours by 2030 in the mid case, compared to about 6,400 gigawatt hours in 2018. The forecast is slightly higher than the previous preliminary forecast and the 2018 forecast, as well. This is primarily due to higher electricity rates in the residential and commercial sector. And we do have higher growth in both of those sectors compared to the previous forecasts.

On the next slide, I have a breakdown of the forecast by different sectors. So you can see here, the residential sector, this is a forecasted capacity. The residential sector is in blue, the commercial sector is in green, and everything else is in red.

So in the residential sector, we have the capacity growing at a compounded annual growth rate of about 8.4 percent between 2018 and 2030, in the commercial sector about 10.8 percent, and overall about 9 percent.

I want to point out that almost half of the state's statewide PV capacity is installed in PG&E's service territory. There is solid growth across the entire service territory but there's -- it's especially robust in the Central Valley.

Okay, so now I'm moving on to Southern California Edison. PV generation is forecasted to more than 13,500 gigawatt hours in 2030, compared to about 4,500 in 2018.

The forecast is pretty similar to the preliminary forecast in 2018 -- sorry, preliminary forecast in 2019 except there's a slight slowdown in 2025 to 2030, and that has nothing to do with the inputs. We found a small error in actually the way -- a small error in the code for the commercial PV model and we fixed it and that was the result. This was not specific to Edison. It was throughout all of the service territories, it just shows up more prominently in Edison.

So in terms of the sector forecasts, there's robust growth in the residential sector for Southern California Edison, growing at 10.5 percent between 2018 and 2030, a slightly slower forecast in the commercial sector of 7.6 percent. This is due to like slower forecast in commercial floor space compared to the previous forecast.

Overall, Edison has the lowest penetration of PV in 2018 compared to the other IOUs. But as a result they have a lot more room to grown, so they have a faster growth in PV adoption over the forecast period compared to the other IOUs.

Rounding out the last IOU, San Diego Gas and Electric, so PV generation is forecasted to grow to about 4,300 gigawatt hours by 2030 in the mid case, up from 1,700 gigawatt hours in 2018. The range in the forecast is slightly narrower for San Diego than the other service territories. And this is largely due to the impact of the Title 24 Standards. The difference between the low electricity demand and the high electricity demand without the Title 24 Standards would have been about 350 gigawatt hours, and half of that is eliminated because of the Title 24 Standards, so it narrows an already narrow range even narrower because of the Title 24 Standards.

So one main difference from the revised forecast compared to the preliminary forecast is we have far more robust growth in the residential sector in the revised than the preliminary. This is due to a stronger growth for households in our forecast. And that, essentially, allows -- it just provides more stock for PV installation to occur. So I believe in the preliminary forecast the residential sector only grew at about four to five percent between 2030 and 2018, and that's up to seven percent in this forecast.

Overall, San Diego has the highest PV penetration rate, especially in the residential sector. So we anticipate that they're also going to reach a saturation point earlier than the other planning areas. So around 2024-2025, we see that saturation point being hit. It actually happens in the low case. But as I've previously stated, the mid case is an average of the low and the high case, so we see that saturation also appearing in the mid case as well.

(Off mike colloquy)

MR. RIDER: On the last slide, but also you can see it in the slide you were just on --

MR. KONALA: Okay.

MR. RIDER: -- the fundamental shape between the initial projection versus where you are now, there's this interesting new inflection point --

MR. KONALA: Yeah.

MR. RIDER: -- a very different shape from the other utilities and different than the preliminary analysis.

Can you explain what kind of fundamental modeling choices were changed to get to that kind of different outcome?

MR. KONALA: Yeah. I'd be glad to.

So there's two different things that are happening. The first is in the residential sector. As I had said, the forecast for household growth is much higher this time. So in the preliminary forecast in 2018, we were reaching that saturation point earlier in the forecast, so the growth in the residential solar market was slowing earlier. Since there is more -- since there are more households, that forecast is being -- that inflection point in the residential sector is being delayed until 2024-2025.

And then there's another inflection point in the previous forecasts in the later half. That was due to that error in the commercial model that we found that was having growth be faster. Once we fix that, we don't see as much growth in the latter half of the commercial sector forecast, so you don't see that going up in the new forecast. So, thank you.

COMMISSIONER MCALLISTER: So I thought -- just I'm a little confused because earlier we talked about the Department of Finance having, you know -- or San Diego having, basically, a lull in the growth of the number of households until the latter half of the decade and then it was accelerating. And this would seem to be sort of the opposite of that.

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: So the penetration argument doesn't quite seem appropriate.

MR. KONALA: I'm only speaking relative to the previous forecasts.

COMMISSIONER MCALLISTER: Oh, right. Okay.

MR. KONALA: So --

COMMISSIONER MCALLISTER: Okay.

MR. KONALA: -- in terms of the absolute value of the households, I’m not too familiar with that but I’m sure --

COMMISSIONER MCALLISTER: Well, just looking at the, you know, the --

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: -- whatever, the change in slope there where it’s accelerating earlier and then tapering off later, which seems to be the opposite of the households.

MR. KONALA: Cary, microphone?

MR. GARCIA: Same thing. I think I can hear myself now.

The overall households I was referring to gets into single multi-family, mobile home, the whole slough that’s modeled in the residential sector.

COMMISSIONER MCALLISTER: Okay.

MR. GARCIA: Sudhakar is primarily going to be focusing on single-family households, so there’s going to be a difference there, single-family. And I think in San Diego, in particular, just single-family itself, there’s a little bit more growth in comparison to some of the multifamily. But his is going to be primarily focused on single-family --

COMMISSIONER MCALLISTER: Okay. So --

MR. GARCIA: -- so you’ll see a slightly

different trend.

COMMISSIONER MCALLISTER: -- so the department of -- the DOF numbers would reveal that difference?

MR. GARCIA: Yeah. We could see --

COMMISSIONER MCALLISTER: Okay.

MR. GARCIA: We would see that. In the residential model we handle, as I said, multifamily high, mid and low, single-family, and then mobile homes --

COMMISSIONER MCALLISTER: Okay.

MR. GARCIA: -- whereas Sudhakar is primarily focused on --

COMMISSIONER MCALLISTER: Got it.

MR. GARCIA: -- single-family households.

COMMISSIONER MCALLISTER: Got it.

And then just one other, I guess it's a question, but based on an observation that in SDG&E territory, you know, they don't have as much seasonal load because the climate is so mild. And they have pretty aggressive -- you know, now everybody is on time-of-use.

And so I guess my sense is that people are getting some pretty outrageous summertime bills, particularly inland in San Diego in SDG&E territory where that time-of-use is really hitting people hard. And that may be what's driving the uncommonly, you know, heavy solar adoption in that single-family.

It would be good -- I guess my question is: How much are you looking at the rate environment in either residential, you know, and/or commercial? Because those, you know, that's -- the value proposition for behind-the-meter solar is all about the rates.

MR. GARCIA: Yeah.

COMMISSIONER MCALLISTER: And so it would be good to understand, in terms of modeling adoption, how that's playing in.

MR. KONALA: Yeah. So we definitely look at the rate environment. We get a forecast of electricity rates and that's exogenous input into the PV model. But in terms of the rate structure, the time-of-use payers, all of that is incorporated. So we look at the current rates and we grow the current rates according to the forecast that's provided. The only thing that we don't do is we don't assume any changes in the time-of-use periods. We keep that constant over the forecast period.

And, I mean, I understand that it could change, it's just so hard to forecast what -- how time-of-use periods could change over time.

COMMISSIONER MCALLISTER: Yeah. No. So you're basically -- you think it's roughly similar across the investor-owned utilities or you think there's some difference with SDG&E?

MR. KONALA: In terms of the time-of-use periods, they're essentially the same. But in terms of the rate difference between peak versus non-peak, there's a huge difference.

COMMISSIONER MCALLISTER: Yeah. Okay. It would be good to understand that a little bit better.

MR. KONALA: Okay. In my next presentation, I'll be talking about storage and, actually, I'll get a little bit into that.

COMMISSIONER MCALLISTER: Yeah. Same set of issues.

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: Yeah. Thanks.

MR. KONALA: So I'm going to round, okay, I'm going to round out the PV forecast by just talking about the two largest POUs. So here, I'm presenting LADWP. Generation is forecasted to grow to about 1,300 gigawatt hours in 2030 in the mid case, up from about 500 in 2018. The forecast is higher than the 2019 preliminary forecast and that's due to us finding an error with the household forecast in the preliminary and fixing it, especially for new home construction. So the change is essentially due to that.

And in terms of the sector forecast, most of the forecast for PV is coming from the residential sector and there's robust growth, about nine percent annually between 2018 and 2030. And this robust growth is essentially because for all of the POUs, there's a lot -- there's initial lower PV penetration than the IOUs, so there's just a lot more room for growth.

So a similar case with SMUD, we're forecasting generation to grow to about 12,000 -- 1,200 gigawatt hours by 2030 in the mid case, from about 300 in 2018. That forecast is slightly higher than the previous preliminary forecast and the 2018 forecast. Overall, SMUD is seeing the fastest growth in behind-the-meter PV of all of the major utilities, about 11 percent per year between 2030 and 2018, which robust growth in the residential sector.

Okay, so that concludes the PV forecast. With that completed, if there aren't any questions, I'll move on to the storage forecast.

VICE CHAIR SCOTT: I think we asked them as we went along.

MR. KONALA: Okay. Thank you.

MR. RIDER: I would just point out that -- well, it's not really -- just bringing it back to the transportation forecast in terms of scale, I mean, this was 40,000 gigawatt hours of behind-the-meter storage and the demand for the transportation is 17,000 gigawatt hours. So just why are you not seeing the growth in the loads? I mean, behind-the-meter, itself, is much larger scale in the forecast that we're looking at right now, in the next ten years.

So, anyway, just thought I would put that in perspective from an earlier comment that you made.

MR. KONALA: Yeah. We're seeing, we're definitely seeing the forecast of robust growth in behind-the-meter solar.

Okay, so I'm now going to get into behind-the-meter energy storage forecast. I'm going to apologize beforehand because this is going to get a lot more technical and wonkish than the other forecast, and probably too wonkish for a workshop, but we felt it was kind of necessary to give stakeholders a good understanding of what we're doing.

So is the first time we've done a forecast like this, so a lot of this stuff is going to be new, so I'll be going slower. But if you have any questions, just feel free to stop me and ask me.

So, again, the objective of this presentation is just to describe the methodology used in the Energy Commission's behind-the-meter storage forecast. I'm not going to be presenting a lot of numbers, per se, but those are available.

So this presentation is broken down into three sections. First, I'm going to describe the methodology used to calculate historical storage adoption. That's actually a hard number to come up with. The second part is just going to describe the methodology for forecasting adoption. And then the third part of the presentation is going to describe how we use that adoption forecast to generate energy consumption due to storage and, more specifically, the hourly charge and discharge behavior of those batteries.

So just, first, the methodology on how historical storage adoption was determined.

The data source I used to get the energy storage information is the Self-Generation Incentive Program, or SGIP. It published a list of distributed generation systems that apply for state incentives. The program has been going on since 2001 but we've seen a change in the program over the years.

Specifically, since 2016, it's become largely oriented toward energy storage projects. So since 2016, there were over 15,000 applications for behind-the-meter energy storage projects. In comparison, I only counted 24 applications for all technologies. That comes out to like a 99.98 percent rate for storage. So you can -- SGIP is, effectively, an energy storage incentive program these days. And I have a chart just showing applications by technology type over the years, so you can see, that's all storage in the last three years.

So once we look at the energy storage data, there's a methodology that we have to use to determine if a storage system or a battery is actually installed. And I just want to briefly go over -- through that methodology. So if anyone is interested, they could download the data themselves, use this methodology, and come up with numbers that are very similar to what I come up with later on. So you can download the SGIP on their website.

Once you download that data, essentially, there's a field that says -- that lists projects by equipment type. So I select -- if the equipment type has storage in it, so it could be electrochemical storage, mechanical storage, thermal storage. But if it says, no, then it's not a storage project and I ignore it. If it says, yes, then it's a potential system that I keep in the pool.

Then I look to see if it's actually been interconnected. And for that, I see -- I look if there is an interconnection date. And if there is an interconnection date in the date, then I count it as an interconnected system, that's actually on the ground and working. If it doesn't have an interconnection date, I look at the program status of the application. If the program status is canceled, I ignore it, the system is not installed. If it’s not canceled, then I look at what the actual project status is. And if the project has -- if payment has been completed or if payment is in progress, or if the status is called ICF, which in Incentive Claim Form, if they filed that the developers are required to have the project installed before they can make that claim, then I assume that the system has been installed, even if there isn’t an interconnection date. So that’s how I come up -- that’s how I determine if an energy storage project is installed.

And once I go through this process, I also estimate an interconnection date, if it doesn’t have one, and then use that as the base data for the forecast.

So once I do that process, here are the numbers I came up with.

At the end of October, I estimate there are about 10,000 stationary home energy or commercial behind-the-meter storage installations in the state, equaling about 267 megawatts. In terms of storage capacity, about 80 percent of that is in the non-residential sector and 20 percent is in the residential sector. Although, if you look at the actual number of installed systems, most of it are in the residential sector. So what that says is the size of the non-residential systems are just so huge that even though there are fewer installations, the overall installed capacity, they make up the majority of that.

In addition to the 267 megawatts of installed storage, there is about another 108,000 -- 180 megawatts of energy storage that's in the SGIP application queue, most of which will likely be installed.

So now I'm going to move on to a description of the methodology for forecasting storage adoption.

So in the past, for forecasting adoption, we used a trend analysis looking at historical installation of storage and, essentially, drawing that trend out into future years. We stuck with that same methodology for the most part with some changes, which I will describe in this presentation. So, but before I get started, just a few observations from analyzing SGIP data.

So for residential storage systems, we find that about 97 percent of them are actually installed together with solar, and only 3 percent are standalone installations without solar. But things are quite different in the non-residential sector. About 63 percent of battery storage in the state are standalone installations, and only 32 percent are paired with solar. So depending on what sector or what customer installing storage, there is a trend to either associate with storage or not to associate -- I'm sorry, associate it with solar or not associate it with solar. So this is going to affect how we forecast storage.

Okay, so first I'd like to talk about how we did adoption forecasts for the non-residential storage. So we continue to the base the forecast on a historical trend for non-residential storage. This is because most non-residential storage systems were standalone. They were not paired with PV. And, also, the number of installations the system size really fluctuate from year to year, so there is no discernible pattern that we can relate to some other item, like solar.

So here's the methodology for the trend analysis. It looked at the total capacity installed in the last historical year, 2018, information from the current year, 2019, and then we looked at the total number of systems in the SGIP Program queue, and then allied a factor of the likelihood of installation.

From that, we used that to calculate an average capacity as in the forecast year. So this is how the trend analysis works.

Because the SGIP Program is an incentive program with applications, it gives us a lot of visibility into what's in the queue. So we feel confident that the program closely forecasts what not only is going to be installed for the rest of this year but, also, probably next year as well.

I see a question. I think questions from the public are --

VICE CHAIR SCOTT: Yeah. We'll take --

MR. KONALA: Take them at the end.

VICE CHAIR SCOTT: -- three minutes of comment from anybody who would like to make a comment at the end of the meeting.

MR. KONALA: Okay.

VICE CHAIR SCOTT: I do have a question for you though.

MR. KONALA: Yes.

VICE CHAIR SCOTT: So you mentioned at the beginning here that you think that most of the non-res storage systems are the standalone system, they're not paired with storage.

And so do you -- so in the future, you also think that they will standalone systems and not paired with solar and that's why you're going to continue to base it on the historical trend?

MR. KONALA: Yeah. I mean, we reserve the right to --

VICE CHAIR SCOTT: Well, update, of course.

MR. KONALA: -- update the adoption forecast. But for now, there's a slight tick up between like five years ago and now. But it's still less than 50 percent, even if you look at us, current year, it's still not, it's standalone.

VICE CHAIR SCOTT: Okay.

MR. KONALA: So we just don't have enough information to make an assumption to change what we're seeing.

VICE CHAIR SCOTT: I see. Okay. Thanks.

While you're pausing, let me just note, if you'd like to make a public comment, just grab a blue card. They're right up in front. And you can hand it to Matt, who's kind of sitting there waiving by the window there.

Or if you're on the WebEx, you can raise your hand and we'll get to that part when we're done with the presentations.

MR. KONALA: Okay, so I just talked about how we forecasted option in the non-residential sector. Now I'm going to talk about the residential sector and how we forecasted option.

So we actually, for the non-residential sector, we only had one scenario. For the residential sector, we actually did three scenarios. In the high energy demand scenario where we're forecasting low storage adoption, we also continued to use the historical trend, just like the non-residential and like we did in the previous forecast. But in the low energy demand case where we're forecasting high storage adoption, we asked -- I'm sorry, we actually linked storage adoption to PV capacity. And I'll describe the methodology in a second. And in the mid case, we just used an average between the high and the low, so there's going to be an indirect link to PV capacity through the low case.

So in terms of the methodology for the low case, first, I calculated an adoption rate for storage, which was, basically, I looked at the total storage that was installed in 2018 and I divided it by the total installed capacity of PV. So adoption rate of storage for people who already had PV or are looking to add PV. And then I held that adoption rate constant throughout time and then multiplied it by the forecast of PV capacity for each forecast year and from that arrived at a forecast of storage adoption each year. When I do that the result was that in the low case there was about 3.4 times more storage capacity in the low scenario versus the high scenario by 2030.

So in this chart, I'm summarizing the adoption forecast between the three scenarios, and also summarizing just exactly what I did. So that chart shows the residential and non-residential sectors by scenarios and the methodology that I applied, as well as just the overall numbers. So about -- we're forecasting about 1,300 megawatts of installed storage capacity in the mid c case by 2030, up from about 200 in 2018. And that is higher than the 2018 forecast in the mid case. Obviously, there was only one scenario in 2018, so the high and the low did not have a comparable from previous forecasts.

So this concludes the adoption forecast part. But I'm still going to talk about the energy generation part and the hourly and discharge profile. So if there's any questions on this, I'll take that. Okay. Okay.

So the energy generation forecast for energy storage is completely -- something that's completely brand new for the revised forecast. This is actually the first time we developed an hourly forecast of energy storage. We've never done that before. And we did that to better account for the effect of storage during peak demand.

We also have an annual energy consumption forecast for storage, but that's just a summation of each individual hour.

Like the adoption forecast for storage, Staff used different approaches for forecasting hourly energy consumption for the residential and the non-residential, and this is primarily due to data availability, and I'll get into that.

So for the non-residential hourly storage forecast, we used charge/discharge profiles from a report published by the CPUC, actually, the CPUC's contractor, Itron and E3. It's called the 2017 SGIP Advanced Energy Storage Impact Evaluation. You can download it from the CPUC's website. But what's significant about the report is they sampled about 150 non-residential storage systems and they published charge/discharge profiles for these systems by building type. So the building types included industrial buildings, food and liquor stores, hotels, retail establishments, schools, and if it didn't fit in one of those categories, into a general category called other. And they also broke down these profiles by systems that were smaller than 30 kilowatts and then systems that were 30 kilowatts or greater.

These profiles for charge and discharging are published by month and hour but they are statewide, so they're utility specific. So our charge and discharge profiles are going to be the same for all of the utilities because we don't have utility-specific data yet.

Finally, the hourly charge/discharge profiles are -- the way they're specified is they're specified in either charging or discharging in kilowatts per rebated capacity of that system. So they're normalized for the system size.

So in terms of the methodology that we used for the non-residential forecast, we applied these hourly charge/discharge profiles to the forecast of storage capacity in the previous part of this presentation to get an hourly storage charge and discharge information.

So here I lifted a figure from the SGIP report that just shows those charge/discharge profiles. So this is average hourly charge and discharge per rebated capacity. This is a statewide number for all non-res projects for all building types. So the darker the value, it's either charging or discharging at a higher rate. If it's closer to white, then it's charging or discharging at a lower rate. But we scrapped this data from the report and we applied to these to our forecast of capacity to get a total hourly charge and discharge information.

Referring back to something that Commissioner McAllister had brought up, so an analysis of the SGIP data and a conclusion of the SGIP report is that non-residential storage systems mainly used batteries to reduce demand charges and not necessarily time-of-use charges, or the demand charges were predominant, just looking at the patterns of charging and discharging. So these customers are primarily looking to decrease their own demand to avoid those charges.

Okay, now I'm going to move on to describing the methodology for describing charge and discharging for the residential sector.

So unlike the non-residential sector, we could not use the SGIP report for the residential sector. This is because the SGIP report had only a very limited sample size, only about 28 systems, and all 28 systems were on tiered rates, not TOU rates. So we believe that the profiles were unlikely to reflect the way the residential storage systems would be deployed.

So to model hourly charge and discharge profiles, Staff used the System Advisor Model, developed by the National Renewable Energy Laboratory, for modeling residential storage. SAM is able to model battery storage when it's coupled with the PV system. So we downloaded the model and we used it for the residential sector.

The general approach that we used is we used -- we modeled a single battery and then we scaled that up to the installed capacity throughout the state to get statewide numbers. And I'm going to describe exactly what we did for that.

So when we're using SAM, we have to specify systems' information regarding the PV system and the battery that we're using. So for the PV system, we modeled a six kilowatt system which was close to the statewide average that I calculated, which was about 5.8 kilowatts. And for the battery, we modeled a Tesla Powerwall. The reason why we chose a Powerwall is because Tesla has about a 50 percent market share in the residential sector. And when I looked at the average residential battery size over the last three years, it was very similar to what the average system size for a Powerwall is. So, essentially, most of the state, the batteries that are being sold look like a Powerwall, so that's why we used it.

I do want to point out one limitation from using SAM, is that we couldn't model the self-discharge of lithium-ion batteries. Anybody that has a cell phone knows that if you leave -- even if you turn off your phone and leave it unplugged for a couple of days, when you turn it back on the level of the battery is going to be lower than when you turned it off. That's because the nature of the technology of lithium-ion batteries is that there's going to be a self-discharge. It's just the physics. So that's going to be the case with any lithium-ion battery, whether it’s an electric car or, in this case, home batteries.

So it’s something that needs to be taken into account, too, but we weren’t able to model that in Sam specifically, so that’s going to be a limitation of the forecast for energy storage, but hopefully we can rectify that in the future.

So in terms of the overall methodology, we selected a PV system and battery that corresponded to the average statewide characteristics. And then we selected about 32 regions across the state between each utility service territory to capture regional variance in solar production. This is going to affect how the batteries are charged. And then we ran these -- we ran SAM at that these 32 different regions for these PV and battery characteristics but we used the default household electricity load profiles that come with SAM, so we didn’t use California-specific load profiles. That’s something we hope to do in the future.

But what we did do was we scaled the load profiles to match annual household consumption in California for each of the 20 different forecast zones that we forecast to.

We input utility rates and rate structures for each of the three IOUs. And then we specified battery charging and discharging behavior based on those rates, and I'm going to get into that in the next slide.

So SAM has several dispatch models for how batteries are charged and discharged. The first one is -- it's a day -- looking forward one day. And then the second profile is looking back at a day. But both of these dispatch models are geared towards minimizing impacts to the grid, ignoring benefits to the consumer. And we felt that most -- consumers mostly control how these systems are going to be charged or discharged or installers are going to program these batteries so that they maximize consumer's benefit. It didn't make sense to use these dispatch models that were going to maximize the benefits to the grid and not the consumer.

So what we did instead was we used a setting called a manual dispatch model within SAM where the user can determine when and how the batteries are charged and discharged.

COMMISSIONER MCALLISTER: Hey, Sudhakar, can -- sorry to step out there for a little while, but on this point, does this include the batteries that would be installed in new construction, along with PV required by Title 24?

MR. KONALA: So for the adoption of energy storage, we just mostly did a trend analysis or we linked battery adoption to PV. So in terms of that, we didn't incorporate any specific regulations, like Title 24, into that --

COMMISSIONER MCALLISTER: Okay.

MR. KONALA: -- into the adoption forecast.

COMMISSIONER MCALLISTER: Yeah. Because it's -- the adoption of batteries in new construction is voluntary but it does get a compliance credit.

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: So there will be some chunk of the market for residential behind-the-meter storage that will be in new construction.

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: And compliance with Title 24, using it as a compliance option, using storage as a compliance option requires that the consumer abide by JA12, which is a dispatch, essentially, guidance for dispatch of the battery.

MR. KONALA: Okay.

COMMISSIONER MCALLISTER: So you might want to check that because it is not what you described in terms of the just customer dispatched. It is actually emphasizing behind-the-meter consumption, self-consumption.

MR. KONALA: Okay.

COMMISSIONER MCALLISTER: So that, you know, depending, we may reopen that and revisit as storage becomes a more mature marketplace. But I just thought I'd bring that up as something that might impact your demand analysis.

MR. KONALA: We'll definitely look into that.

COMMISSIONER MCALLISTER: Okay.

MR. KONALA: It's not incorporated into this forecast --

COMMISSIONER MCALLISTER: Okay.

MR. KONALA: -- per se.

But -- so the things that we did require in terms of charging and discharging behavior is we -- when we used the manual dispatch model, we required it to meet all incentive requirements, so there are two of them that are specific.

So when storage is installed with solar, or if there's an existing storage system, storage can get the Federal Incentive Tax Credit. But one of the requirements is that the battery must charge using solar or renewables. So this was a requirement that we used in the manual dispatch model.

Another requirement, which is of the SGIP Program, is that the battery must fully charge and discharge at least 50 times a year, or at 687 kilowatt hours per year. So this was a requirement that we had as well.

We also assumed that the consumer is going to be rational, that they're going to maximize their bill savings, so the battery is going to be charged and discharged in a way that maximizes bill savings. So it's going to be charged during daytime because it's required to charge in the daytime using solar for the Federal Incentive Tax Credit, but that's also when the lowest electricity rates also occur. But it's only going to be discharged during hours where it makes sense financially.

Finally, a requirement was placed that the battery is not allowed to discharge below 20 percent of its reserves -- of the total capacity, which is a reserve for backup power. This is fairly consistent, what we're seeing, with systems that are being deployed by the large battery manufacturers and installers, like Tesla and Sunrun.

So, okay, so next I'm going to get into charge and discharge profiles for the three big utilities, the IOUs.

So here's a chart showing the discharge behavior that we programmed for batteries for PG&E's territory. So this chart shows by month and by hour when a battery is allowed to discharge and when it is not allowed to discharge, with the green representing the hours where it is allowed to discharge.

So, basically, the battery is allowed to discharge in the summer months during peak hours.

MR. RIDER: By allowed, you mean it’s economical?

MR. KONALA: Yes.

MR. RIDER: Okay.

MR. KONALA: Yeah.

Obviously, PG&E also has peak rates during the winter months. But the rate difference between peak and off peak in the winter months was only 1.5 cents. And since we don’t, in our forecast, we don’t -- we keep that ratio the same because we do a forecast of average rates. So at that difference of 1.5 cents, and taking into effect the roundtrip efficiency of batteries, which is only about 90 percent, it is actually uneconomically to do a charge and discharging during the winter months at that peak rate. So for the purposes of PG&E, for the customer, it doesn’t make sense to charge and discharge during the winter months.

So we --

MR. RIDER: And just out of curiosity, when you say discharge, you mean onto the grid, not into the self-consumption?

MR. KONALA: We’re mainly looking at self-consumption.

MR. RIDER: Okay. So, okay, just trying to understand then --

MR. KONALA: so --

MR. RIDER: -- I mean, the battery is not being utilized for most of the months?

MR. KONALA: Yeah.

MR. RIDER: It's just sitting there?

MR. KONALA: It's -- it can be. But from a financial standpoint, it doesn't make sense to do it.

MR. RIDER: From a sense of wear and tear on the battery?

MR. RIDER: Not -- wear and tear on the battery, true, but also from the rate difference. So I don't remember the exact rate for the winter months but the difference was 1.5 cents between peak and off peak. That difference is not very big.

There's an energy penalty to using your battery; right? There's a 90 percent roundtrip efficiency. So if you're charging up the battery, what you can get out of it is only going to be 90 percent. That ten percent loss is going to be greater than the 1.5 cent gain that you get.

MR. RIDER: And -- but there's also a difference in export value of exported solar production; right? And so if we're assuming that all these systems have solar production, there's -- I mean, NEM 2.0 has a lower compensation rate for exports than -- also, on top of that, and so that's not enough to overcome the efficiency difference?

MR. KONALA: Yeah. I has to be like at least five cents, I think, for PG&E.

MR. RIDER: Okay. All right.

MR. KONALA: But I can recheck that and get back to you.

So assuming these charge and discharge profiles, we're estimating that there will about 72 to 90 full charge/discharge cycles for systems installed in PG&E's territory, depending on where they're actually installed. So we're meeting the minimum requirements of the SGIP Program, that it be charged and discharged at least 52 times.

So moving on to Edison, a similar chart here but a different charge and discharge profile because of the different time-of-use rates.

So for Edison, it makes sense to allow the battery to charge and discharge year-round. Edison's time-of-use rate structure incentivizes arbitrage, end during the winter months. And based on the rates, which I've shown to the figure on the right, we estimate that the battery systems are going to be fully charged and discharged a about 250 times a year.

In terms of energy consumption, I calculated a capacity factor for Edison for the storage systems and it came out to about 2.3 percent, which is very similar to what we've seen in the literature for the capacity factor for storage systems that charge on a -- charge and discharge on a daily basis, so it seems to be in line.

And then, finally, for San Diego, this is more like PG&E, the systems are allowed to discharge during peak hours in the summer months. But the time-of-use rate difference between peak and off peak in the winter months, again, is very low. So I took this figure off of San Diego's website. There's only a one cent difference between peak and off peak. And, again, economically, it doesn't really make sense to discharge the battery, the wear and tear on the battery, you know, and then loss in roundtrip -- the losses due to roundtrip efficiency. So we only have it charging during the summer months.

Overall, we estimate that the battery will be charged and discharged about 100 -- for 100 cycles for the -- for each year of the forecast.

Okay, so with those charge and discharge profiles, we incorporate that into Sam and then we run Sam using the 5 kilowatt, 13.5 kilowatt hour Tesla

Powerwall battery and SAM provides us results. We convert the SAM hourly charge and discharge data into charge and discharge profiles for our rated capacity per kilowatt. And then we apply these profiles for all 32 regions to create a charge/discharge profile for the 20 forecast zones. And then we add up those forecast zones to get profiles for each of the three utilities. From that, we're able to generate an hourly forecast for residential storage systems for each of the different planning areas for the IOUs.

So I don't have final energy numbers for storage systems. That's because the total energy consumption due to storage -- net consumption due to storage is actually very small. We're only talking about on the range of about 100 to 150 gigawatt hours. That's very small compared to the 40,000 gigawatt hours for behind-the-meter solar. So it's basically a rounding error for the rest of the forecast. But where it does make an impact is on the peak forecast, which Nick is going to talk about.

I did want to make several comments. So this was our first attempt at doing this type of forecast for storage but we expect it to continue to evolve over time as we get a lot more data and as we incorporate feedback. And we expect there to be a lot of incremental improvements over time, including as we get more data on charge and discharge behavior for battery systems.

There's a new SGIP report on storage that's scheduled to come out. It was supposed to be out but it's scheduled to come out soon. So once we get more data, I think from that, we'll probably make some more changes to the methodology and have better forecasts in the future.

COMMISSIONER MCALLISTER: Yeah. Thanks a lot. I think this is great. I mean, we have to -- it's a really good foundation and then we have to figure out what that marketplace is doing with storage so that we can model that; right?

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: And I think we kind of don't quite know what's going on quite yet.

But to Ken's point earlier, I'm not sure it's always the right comparison to compare on peak and off peak. It may be that a given kilowatt hour either goes in the grid or it goes into the battery. Like if you're producing PV, it either goes into the grid at given moment or it goes into the battery.

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: And the difference there could be actually quite significant because if it goes into the grid and the accounting and the NEM rate is such that it's only giving you the avoidable wholesale cost, which is like two cents or three cents, then that's your comparison with whatever the on-peak, you know, retail rate that you're saving by using it onsite.

So I think we need to really dig into the -- how the rates are being applied in each, you know, in each time period, in each service territory, each season to make sure that we're doing that accounting properly and understanding what the difference in value for any given PV-generated kilowatt hour actually is. Because that really is going to drive the value proposition for storage, in addition to any, you know, on-peak/off-peak difference.

MR. KONALA: So we'll definitely look into that, but just -- I just remembered something.

So we did talk to some of the storage installers. And one of them has stated that they only do charging and discharging in the summer months and not during the winter months in PG&E's territory. So, in practice, they're actually following what we're trying to model, at least for the time period. That could change going forward.

COMMISSIONER MCALLISTER: Okay. That's helpful. And as the rules of that metering, you know, get tweaked and morphed and stuff, that will interesting to keep track of.

MR. KONALA: Yeah.

COMMISSIONER MCALLISTER: Thanks for all the hard work.

MR. KONALA: Thanks.

VICE CHAIR SCOTT: All right. Thank you very much.

I want to be mindful. We've gotten lots of great presentations and a lot of very good detail but we are quite a bit behind time.

So, Nick, I'm hoping you can do your presentation between now and about 3:05, 3:10.

And then, Mike, if you start around 3:05, 3:10, if you can be wrapped up, maybe around 3:45? And then that will leave us some time for comments and get us a little bit back, closer to schedule, just to be respectful time who's here listening in. That would be great. And I am looking forward to additional interesting presentations. So, Nick, please take it away?

MR. FUGATE: I'm sorry to say, no one has ever accused me of talking fast but let's see what I can do here.

All right, good afternoon, Commissioners. Nick

Fugate. And I'll presenting the results of our hourly forecast. I'll be referring to it as CED 2019, or California Energy Demand 2019 to 2030 revised forecast. And we're employing, again, the hourly load model that we used last cycle. This is our top-down model specified at the system level for each TAC in the CAISO control area. And has been stated in previous workshops this year, we will soon have a second hourly model. Our updated hourly electric load model, our HELM 2.0, which is a bottom-up model, making use of load shapes developed by ADM for each of our end uses, sectors, building types, forecast zones, that we used in our annual demand models, as well as shapes for important demand modifiers.

Although it's in our -- it's in the final stages of development, the HELM 2.0 was not -- wasn't complete in time to make use of in this forecast, which is why we are -- everything I'm going to be showing here is coming from our HLM model.

But regardless of the specific model, the motivation for doing an hourly forecast is the same, and we've already touched on that quite a bit today in other presentations. Demand modifiers, such as PV, storage, electric vehicles, alter the observed net-system load profile relative to what we've traditionally seen.

I've included here for illustration a sample modeled hourly profile for PG&E TAC area on July 30th, which is a weekday in each of the years that I'm showing. You can see the pronounced impact that significant amounts of behind-the-meter are having, creating this steep ramping period between the early afternoon and evening, and also you see the peak hour shifting from hour 18 in 2020 to hour 19 in 2025. And in 2030, on this particular day, so electric vehicle charging very nearly shifts the peak hour even later.

So peak load is an important consideration to system planners. And anticipating the timing of the peak hour is important so that we can accurately capture the contribution of demand modifiers.

So I've just touched on a couple of these uses case but, more directly, we used the results of our hourly model to derive annual peaks for the IOU TAC areas and for the CAISO system as a whole. Our annual peak load forecast is something we routinely adopt as part of the IEPR. It feeds into some of the planning cases that Commissioner McAllister mentioned at the start of this workshop.

Beginning last year, with the 2018 update, we also began adopting monthly peaks for use and resource adequacy. And then the detailed hourly results are actually an important input for any sort of detailed system modeling, such as production cost modeling that we do internally here at the CEC.

So a little bit about the method. I'm going to keep this high level as the structure hasn't changed since the last time we ran this model.

HLM is actually modeling load ratios for each hour of the day. That is the ratio of load in each hour of a year to the annual average hourly load for that year. This is a convenient way to do it as the model doesn't have to account for economic and demographic drivers that can impact the absolute magnitude of load. Those sorts of considerations are taken up in our annual forecast that Cary discussed earlier which we -- that's the forecast that we then apply these average hourly load ratios to derive the hourly projections.

So this hourly consumption load is then adjusted to account for the impacts of incremental demand modifiers, such as PV and electric vehicle charging, battery charging efficiency, et cetera. And for each of these load modifiers, we've developed a distinct set of profiles.

So there's a weather normalization step to this. The model takes, as an input, hourly weather effects, such as temperature and dew point. We've detailed historical hourly weather data for the last 18 years that we use to run simulations. And then we alter the day of the week that the simulation starts on so we get different calendar effects to. And this is gives us about 126 -- or exactly 126 simulations, each with 87:60 ratios. And we rank order them in each simulation from highest to lowest. And for each rank we select a median across all simulations and this becomes our weather-normalized ratio.

But then there is a final and tricky step of assigning these load ratios to actual days and hours of the year. And doing the calendar assignment we want to be sure to preserve coincidence across different TACs so that the results of the hourly TAC forecast can be summed across ours to get an hourly forecast for the CAISO as a whole, so we do this using average historical loads since the sum of an average is equal to the average of a sum. However, if we were to stop after just that first step we'd be understating peaks in the shoulder months, which have significantly wider distributions of load relative to the summer and winter.

So we add a few more steps to this process, that is within each month, we rank the ratios and find the rank average across historical years. Similar to what we did at the annual level, instead of averaging across specific hours of each month, which will have wide distributions, we find the average of the highest historical ratio in the month and then the average of the second highest, and so on. Then we assign the highest average peak ratios to the day type and hour within the given month that has the highest historical average load ratio. The second highest is assigned to the second highest and so on.

So we do this for every month, and then we look at the entire year, and then we rank every hour of the year. And this gives us the 87:60, basically, calendar that we use to assign the load ratios from the first step.

So here's our key inputs. The set of load ratios that we're using for the revised forecast are identical to the preliminary. What has changed is that we are applying these ratios to the revised consumption forecast that Cary discussed, including impacts from the revised PV projections and storage projections that Sudhakar just described. We are also calibrating to the results of our 2019 annual estimates of weather-normalized peak load for each TAC. So this is something -- we didn't have this weather-normalized annual peak estimate for the preliminary because summer had not ended yet. We need to wait for that summer data.

So although our forecast of PV adoption has changed, the actual generation profiles that we're applying to this forecast are the same, the ones developed by E3. We're using newly developed efficiency and vehicle charging profiles taken from the EPIC-funded Load Shape Project with ADM. This is the same project that is -- that the HELM 2.0 is going to be coming out of. And I've included a link here to the detailed report of that work for anyone that wants to dig into it.

Our annual climate change impacts are no longer being distributed as they were in the previous forecast in proportion to hourly load. Instead, what we've done this time is we've estimated an elasticity for every hour of the year. That is a percent change in load relative to a percent change in temperature. And we've combined that with the hourly climate change impacts -- sorry, the hourly climate change temperature impacts that Scripps has developed for us.

And then impacts from the rollout of default TOU rates were developed by Lynn Marshall, who made use of the various pilot studies and load impact assessments that were conducted by the IOUs.

So Sudhakar discussed the development of behind-the-meter storage charge and discharge. Since this is the first time we're including storage impacts in the forecast, I thought I'd show an example of what this profile looks like, or these profiles.

This is the overall res and non-res profile taken from a summer weekday in a PG&E TAC in 2030. Negative values here represent charge. Positive values represent discharge. The residential systems, you can see charging with PV production and discharge during the time-of-use window. And the non-res PV systems, as Sudhakar mentioned, are being utilized mostly to defer demand charges, so they appear to be discharging during the day and charging at night.

I also wanted to show an example of an EV charging profile, this one taken from a summer day in 2030 from the SCE TAC area. I included a weekend and weekday profile to show the increased workplace charging between 6:00 a.m. and noon during the week. In either case, you can see a pronounced response to the time-of-use peak rate window. Also, the highest charging loads are late at night or in the very early morning.

Which circles back to my first graph. The transportation electrification is a significant contribution to long-term growth in our consumption and sales forecast. But we'll have something of a lesser impact on peak growth. And while we eventually reach a point where adding more PV by itself will have no incremental impact on the timing and magnitude of peak, this demonstrates our other demand modifiers could continue to shift the peak hour, potentially even past sunset.

So, as I mentioned, one of the other key inputs is our annual weather normalization -- weather-normalized peak estimate. So I'll describe this process as well. It's relatively straightforward.

We fit a linear regression model to the last three years of summer load and temperature data. The idea is to capture the daily peak load response to temperature apparent in recent history. And once we've estimated that model, we then simulate daily peak loads for an entire summer, using the last 30 years of historical temperature data. Then we take the maximum peak from each simulation, so 30 in all, and select the median value as our one and two normalized value for 2019.

And you can, the model here is pretty simple. As predictors, we use the maximum daily temperature, as well as the maximum temperature from the previous two days. We also include daily minimum temperature and dummy (phonetic) variables for year and month, as well as an indicator for a normal business workday.

So here I'm showing our model fits statistics for this weather normalization process, both for the model performance across the entire range of predicted values, and then just for the top five peak load events in the estimation years. We make that top five distinction because, ultimately, it's the peak values that we really care about.

The thing I want to call attention to here is that the root mean squared error, which is the statistic that gives us an indication of how wide or narrow your distribution of errors is. It improves for PG&E when evaluating just the extreme values, which is fantastic, but it worsens for SDG&E and SCE in particular, indicating that our -- potentially indicating that our predicted extremes are relatively far from the observed values.

So some of you may recall, that last cycle our forecast staff agreed to retain the same model from one forecast to the next so as to avoid any movement in our weather-normalized peaks that could be introduced purely through methodological inconsistencies in how we're doing this, so we've done that. So the results I'm showing you are from the same model and method. But we also committed to routinely showing these performance statistics in case the model seemed to be underperforming.

So that large error band around the extreme values, as I mentioned, in SCE TAC is worth keeping in mind as we look at the model results here.

I'm comparing the weather-normalized values for 2019 to the 2018 normalized peak from last year's forecast update by each TAC area. And we're slightly lower across the Board but, especially in the SCE TAC, a nearly 500 megawatt drop from 2018 to 2019.

I'll make a point of saying that we're interested to hear -- we've provided all of our -- all of this. This was discharged at a DAWG meeting a couple weeks ago and we provided information to, about our forecast, to SCE. We're interested in hearing their perspective or reaction to this weather-normalized peak.

I, perhaps, should have shown the observed peaks as part of this table, but you can actually see that in the next series of slides here.

So here's our one and two non-coincident peak forecasts for the PG&E TAC. That top red line is our end-user consumption peak forecast which represents peak demand on the customer side of the meter, regardless of whether that demand is being met by grid or by -- by the grid or by onsite generation. The bottom three plots are, from top to bottom, are our mid baseline net peak which accounts for self-generation but which is unmanaged by additional achievable efficiency, or AAEE. Then our mid baseline peak managed by low AAEE. And then the bottom plot is our mid baseline managed by mid AAEE.

I'm showing these two manage scenarios specifically because they're the ones that the joint agencies have agreed to use for system planning, the mid-mid for statewide analysis and then the mid-low for local studies. And all of the net-peak scenarios begin from our 2019 weather-normalized value. The purple dot there by itself is the recorded peak for 2019. So you can see here, for PG&E, we have approximately a 500 megawatt downward adjustment from the observed peak.

The addition of PV drives the forecast downward in the first couple of years. But in 2020 -- no, I'm sorry, in 2021 the peak hour shifts from hour 17 to hour 18. And so at that point the marginal impacts from additional PV taper off. And then a year later, in 2022, the peak hour shifts yet another hour later, further reducing the impact of additional PV. And after that point, the peak forecast continues to grow.

So by the end of the forecast period the difference between the mid baseline and the mid-mid managed peak forecast is almost 1,000 megawatts of load reduction from additional achievable energy efficiency.

And here's a similar set of plots for SCE. In 2019, our weather-normalized estimate amounts to nearly a

700 megawatt downward adjustment. The model peak hour shifts from hour 16 to hour 17 in 2025, and then to hour 19 in 2026. The SCE TAC sees relatively greater peak contribution from climate change and electric vehicle charging, each adding a couple hundred megawatts to peak growth by 2030.

And I should mention that at the very end of my presentation, I have a set of appendix slides which include the contribution at the hour of managed system peak of all the different demand modifiers that we layer into this hourly analysis.

Also, in 2030 the mid-mid managed peak is impacted by over 1,100 megawatts of AAEE savings. And that mid-mid managed peak declines by about a half a percent a year in the first half of the forecast, then grows at about the same rate, netting almost no change over the ten-year forecast horizon.

SDG&E saw a slight upward adjustment in their weather-normalized value. SDG&E sees no peak shift during the forecast because, you know, as Sudhakar mentioned, they have a significantly high penetration of PV already and so the peak shift has, essentially, already happened.

Additional PV has now marginal impact on peak. And so the consumption peaks and the unmanaged peaks track very closely. AAEE accounts for a 238 megawatt spread between the mid baseline and the mid-mid managed peaks in 2030.

I have three more TAC-specific slides, each showing our monthly peak projections this time, plotted against the last ten years of observed system peaks in each month. All the peaks shown here, projected and observed, are non-coincident. Each colored line represents a forecast year. I've included only 2021, 2022 and 2023 to keep the graph readable, and also because those are the years that stakeholders identified as being the most important for R.A. And the black dots are the distribution of historical peaks.

So for PG&E, it fits nicely, if a little high in the distributions.

SCE, on the other hand, sits a little lower and, you know, a little lower in the summer months and actually higher in the winter months. And a portion of this has to do with the variable contributions of solar in different months. But also a portion is likely an artifact of the model calibration to the weather-normalized peak. The calibration step is a linear transformation of every hour such that the rank order of the consumption load ratios and the total annual energy are preserved. Calibrating to a lower peak has the effect of reducing high load ratios, such as those that are common in the summer, and then increasing the low ones that are common in the winter.

And for SDG&E, again, this sits pretty low in the historical distributions. But, again, SDG&E has seen significant penetration of behind-the-meter solar in recent years.

And for completeness, I've included the CAISO system. This is actually just the combined TAC, so VEA is not included here. But adding VEA won't change the appearance of this graph noticeably.

So this is the -- no, I'm sorry. There's some concern on a recent stakeholder call as to whether the system peak might shift to a different month with this forecast. And I'm showing here that the system peak is still assumed to occur in early sept.

MR. RIDER: Nick, a question on the San Diego Gas and Electric TAC on month seven, I guess that would be July?

MR. FUGATE: Um-hmm.

MR. RIDER: I mean, given the month-by-month adjustment that you've been doing, I find it odd, and the and at least the square progression methods and things, that the lines fall outside of every single recorded piece which would really up your error. What -- can you explain why? I mean, literally, every other line falls within the distribution. Why -- what's going on with the methodology on July?

MR. FUGATE: So I'm not surprised that someone noticed that. So this is not dissimilar to what we saw in the previous forecast. The hourly load model, you know, for SDG&E, it was always the poorest fit for our model. And, in particular, relative to average observed peaks, that month seven and eight have come in a little low. But you're also, on top of that, you know, we are, you know, expecting this to be relatively -- the peaks to be relatively low in the summer months compared to recent history.

MR. RIDER: Well, I guess you were describing in the beginning of your presentation a monthly -- a month-by-month fit that you do of whether to try to --

MR. FUGATE: Right. That's for the --

MR. RIDER: -- get it (indiscernible).

MR. FUGATE: -- for the assignment of the load ratios.

MR. RIDER: Right.

MR. FUGATE: So for the calendarization effect. It works pretty well for most of the TACs. And -- but for SDG&E, we still get a slightly understated, and it just shakes out, we get a slightly understated month seven.

MR. RIDER: Okay.

COMMISSIONER MCALLISTER: I mean, it actually looks kind of odd, not just for month seven. I mean, all, you know, all the points are above the curve there. But even for August and September, it looks, you know, it looks a little bit low and you've got the --

MR. RIDER: Yeah. I'm a little confused because I thought that this was like the least squares fit of some kind based on historical data in terms of calibration. And I don't know how that wouldn't correct the --

MR. FUGATE: Right. So let me back up a little bit.

We do have a slight -- so the calibration is to the annual weather-normalized peak in 2019, so we do have an initial slight decline in the first couple of years to the annual peak. And, actually, that 2019 observed value is in this data set. It is, I believe, the second to the lowest value there in September.

So, I mean, you know, we're fitting the hourly model, the estimation. The number -- the years that we're using for the estimation I think are the 2018 back to -- we're using six years of recent data to fit the model. But as you, you know, add more --

MR. RIDER: Right.

MR. FUGATE: -- add more PV, you're going to have -- you know, expect to be at the low end of that --

MR. RIDER: Okay. Thank you.

MR. FUGATE: -- distribution.

COMMISSIONER MCALLISTER: All right. Okay. That makes sense.

MR. FUGATE: So this is my closing slide. Everything after this, I've included only for reference. I want to just summarize where we're at here in terms of finalizing the hourly forecast and, by consequence, the annual and monthly peaks that we'll be putting forward for adoption in January.

We've already provided the IOU TAC area peak forecasts and the detailed hourly results to key stakeholders for the planning scenarios, like I said, the mid baseline, paired with the mid-mid and mid-low AAEE. We'll be docketing the full hourly results for all scenarios, hopefully tomorrow or Wednesday.

The comment window following the workshop closes in two weeks. And during that time, our staff will be available to -- for additional discussion with stakeholders. So you can reach out to me or to Cary and we'll arrange to have the necessary people on a call.

And, again, we're particularly interested in additional perspective or reaction or analysis on that weather-normalized 2019 value for Southern California Edison. And also be very grateful for any feedback we receive before the comment window closes on that, even if it’s just informal, so that we can, you know, have as much time as possible to consider any adjustments that might need to be made.

So with that, I will -- if there are additional questions from the dais?

VICE CHAIR SCOTT: I don’t have any additional questions. I’m seeing shaking heads.

I do want to underscore, though, Nick, what you said to our stakeholders and the utilities, especially, that the staff is available for the additional discussion, and that we are looking for the reactions to the 2019 weather-normalized peak estimates. So we hope that folks will take that call seriously and engage with the staff and help us improve an already expert analysis. So thank you very much for that.

Let’s turn now to the final presentation today, and that’s going to be by Mike Jaske.

MR. JASKE: Good afternoon. For the record, Mike Jaske with Energy Assessments Division. And what I’m going to do today is describe an exploratory study of the impacts of fuel substitution. This is not part of the baseline or managed forecast. It's a parallel study that is too uncertain to include in baseline or managed forecasts and presented here today to receive comments and input from stakeholders so that we can improve our analysis and bring forward something, eventually, when fuel substitution programs start emerging and become more mature.

So the objective here was really to understand the relative importance of alternative assumptions. And it's limited to the residential and commercial building sector. We wanted to develop a tool that could look at both annual energy and hourly electric load impacts and provide a starting point for looking at the generation resource addition issues associated with the loads that I'll be showing you.

And I should say that a version of this analysis was provided to our Electric Analysis Office. And they'll be presenting their generation assessment at the workshop on Wednesday of this week.

So trying to be quick here.

I presented a sort of an initial layout of this project back at the September 26th workshop. And what I'm going to do here in part two is sort of tell you the -- more of the results, particularly focusing on some sensitivities and the hourly profile side of things, and less so on the annual energy. Oh, and there's a detailed report that it's in review right now. And that report, plus some Excel files that lays out the inputs and the results, will be posted in the next couple of weeks to aid stakeholders.

So these are the same scenarios that I described back in September, there's five of them, two having to do with new construction electrification, two of them having to do with retrofit of existing residential space and water heating, and then the last one, what I'm now calling pseudo AB 3232, looks at the 40 percent reduction from 1990 fuel use, not from the GHG inventory. So it's a must more simplified scope of what the eventual AB 3232 analysis has to tackle.

And there is an error in the first sub bullet. At that point in September, I was trying to conform what I did to what was included in SB 350 analysis. And that was a scenario that rose up to 15 percent. In fact, I have reverted back to the original analysis which is only a ten percent increase in -- or penetration of new construction by 2030.

So very quickly, the approach, we start with the staff's 2019 IEPR Natural Gas Demand Forecast by utility, by sector, and by end use. We devise electrification scenarios at the sector and introduce level. We quantify the annual amount of natural gas that's displaced, and then the electric energy that's added at the utility sector and end-use level. And then in the last step, that hourly -- that annual electricity energy that's been added is spread across all the hours of the year using load profiles to get an hourly load impact by sector and end use, which we can then add across all the individual hours to get sector, utility, and even multi-utility impacts.

This flowchart essentially shows you all of what I just said in a graphical form. I'll just note that the middle box there, where it says, "incremental electric hourly load calculation," that's an adaptation of the tool that we developed several years ago for hourly AAEE. And it's really just an Excel method of taking that annual energy, whether it's positive savings from energy efficiency or negative savings from fuel substitution and smearing it across the hours of a year using a load profile.

And then just for completeness, being specific here about what levels of disaggregation exists. So there are five electric utility service areas. And I should say these are, the way the staff's natural gas demand forecast is projected is on an electric service area basis. So PG&E gas service area is the combination of PG&E and SMUD. And, correspondingly, SoCalGas is sort of the summation of Edison and LADWP, leaving out a few little pieces, like Burbank and Glendale. So this coverage is about, roughly, 90 percent of the electric load of the state and that was sufficient for this exploratory project.

Two sectors, residential and commercial building, ag, industrial and other commercial left out, within residential there are five end uses, as noted there, and in the commercial building sector there are six end uses.

So the key assumption and equation that drives all of this at the individual sector end-use level is the presumption that the level of service, before and after fuel substitution is the same. So if you take something simple, like a natural gas water heater, the consumption of that natural gas water heater is the product of the level of service that's being provided in terms of hot water times the efficiency with which that's delivered.

And we want that level of service, the amount of, essentially, the amount of hot water that end users have available to them to be the same when we have an electric appliance that is generating the heat, the heated water. And so that amount of energy is the level of hot water service divided by the average electric efficiency. And so that is shown in this equation that says, "Incremental electric energy is displaced natural gas energy times the ratio of the natural gas efficiency and the average electric energy efficiency." And we'll repeat that, essentially, over and over again across all the sectors and end uses.

So this is an example of how that basic construct is applied. On the left-hand panel we have all of the end uses in the residential sector, and the total, the amount of natural gas that's been displaced in one of these scenarios. We have the assumptions in the middle panel of what the natural gas efficiency was and what the electric efficiency was for each of those end uses. You can compute the amount of annual electric energy that corresponds to that amount of fuel substitution.

And you can see in the original assumption panel that all of the end-use efficiencies were assumed to be the same. These were the values that were first developed as part of the original Fuel Substitution Project that we undertook as part of the 2017 SB 2350 study. And initially, I just took those very same ones and applied them across all of the end uses.

In the revised panel on the right-hand side of this slide are, obviously, must more specific numbers for each end use. These were some of the initial values that came to us back in September from Navigant Consulting, who is assisting Staff in developing a more sophisticated model of this whole fuel substitution process. And so these are particular -- a result of an analysis of individual technologies within the named end uses here.

And you can see that, even though there's quite a variety in the change from the middle panel to the right-hand side panel, the total amount of energy added is actually only about seven percent less. Some end uses go down, some end uses go up, and the mix didn't change so much.

These are the actual annual energy impacts. I think these are the same, except for one, the very first scenario, the first row, the reference case, SB 350. As I reported in September, you can see that these all are sort of ordered in the same size impact as the way I described them. New construction, even at the 25 percent share level, doesn't really get you very much gas displaced or energy added, compared to just relatively low levels of residential retrofit.

And, of course, the so-called pseudo AB 3232 scenario that brings in the commercial sector has a much larger amount of gas displaced or electric energy added. And that is the scenario that the Electricity Analysis Office has assessed and will be describing in the workshop on Wednesday.

So let me now turn to how we take those annual electricity impacts and convert them into hourly electric loads.

So one of the really important goals of this exploratory project was to try to understand the hourly load impacts. And to do that, of course, we need load profiles to match up to those amounts of electric energy by sector and end use. There were a series of different sources that were explored and various versions of the basic tool, made use of different combinations of these sources over a period of some months as we were just sort of trying to understand, if you assumed this profile, what would that translate in terms of overall result?

So we started with the package of end uses that were developed in conjunction with the 2017 AAEE projections. These have, actually, been substantially updated and replaced in the 2019 AAEE study, as Ingrid Neumann has indicated in several presentations. These were probably sufficient for simple end uses, like cooking or maybe even water heating, but very deficient in that we don’t have any experience in the AAEE realm of electric space heating. So electric space heating was a big deficiency in terms of that original source

There was a SoCalGas study that a team of Navigant Consulting people did for that utility. That was published, I think, in the summer of 2018. We contacted Navigant to get the profiles that they assumed in that study. It turned out they were actually traced back to an E3 IRP analysis. There's a lot of circularity going on in the industry. They turned out not to be very satisfactory.

So we moved on to another source which was open E.I. They had residential space heating profiles that were developed using the building simulation model situated in the climate of hundreds of different locations around the country. We downloaded 20 or 25 of those and sort of mapped them into electric utility service areas and tried those.

And then lastly, as Nick mentioned earlier, the HELM 2.0 Project delivered profiles to us somewhere around February or so of this year. And even though the HELM 2.0 model that made use of those profiles isn't yet ready, we're able to update the profile selection by making use of those ADM profiles.

And so what I will be presenting in all the rest of these slides is kind of a composite of mostly ADM profiles with a few minor end uses traced all the way back to the 2017 AAEE package.

And just to give you an idea of what the different profiles mean in terms of results, there's three different vintages of this tool that I'm showing here as rows. And the columns are the date at which the maximum impact across both residential and commercial building sectors and all the end uses within them result.

So in the original version that I'm reporting here, the Version 9C, all of the maximum impacts take place on the same date in November, which was a little surprising, one of the reasons to sort of move on to another source.

The middle version there with open E.I. profiles by zone, weighted together with utility service area sort of composite profiles and all the other profiles the same as the previous version, now is starting to show come diversity. So the multiplicity of zones and the individual climates associated with those obviously lend themselves to having different results. And so PG&E and Edison are now peaking in December. And San Diego, curiously, is peaking in March. And the composite across, on a coincident basis, across the ISO is the same date as Edison in December.

And in the last row, bringing in the ADM load profiles with a few of the 2017 AAEE package, even more diversity. We understand that these profiles are a composite of several different weather years. And I think that's leading to this increased diversity of the date of the maximum incremental load. So PG&E remains in December a little bit earlier in the month. Edison shifts over to January. San Diego moves into late November. And then the coincident across the three TAC areas within the ISO is not quite the same date as Edison but, perhaps, part of the same cold weather event.

And so this is instructive to us in terms of understanding how space heating profiles cause the results to change the diversity of approaches in how these profiles were developed, the weather assumptions that go into them, and are they appropriate for the purpose that we have? It raises, you know, lots of issues, and this was part of the whole idea is to understand what kind of sensitivity the results might be encountered.

So all of the next few slides I'm going to show are this kind of hourly result. They're all going to be for the year 2030. They're all going to be for the pseudo AB 3232 scenario. And I chose that to show here today because that's the scenario that has the greatest amount of electric energy on an annual basis of the five scenarios. And so all of these effects are magnified, you know, like the hourly level at the same level that they're magnified at the annual energy level.

So here we're looking at three days, January

21st, 22nd and 23rd. The peak day that I showed on the last slide of January 23rd has a composite of a little over 14,000 megawatts of incremental electric load on a, quote, "statewide basis," meaning it's the five electric service areas, some together on a coincident hourly basis.

You can see right away that each day has two peaks, a primary and a secondary, so it's a very bimodal distribution. All of the service areas have that same basic shape, although it's more extreme in some compared to others. The blue and orange lines here are PG&E and Edison respectively. And since they're so much bigger, they really drive the overall composite statewide results. The other three utilities don't matter nearly as much.

And you can see, again, that they all behave in a very similar fashion. There's a morning peak around hour seven or eight. There's an evening, which is the secondary peak. And there's a primary peak in the evening hour around hour 19. And that pattern just repeats over and over again.

Drilling down a little bit into sectors, so same scenario, same days, summing across those five utilities to give the residential total and the commercial building total. You can see here that the residential total in orange is far larger than the commercial building total in blue. And so the residential pattern is driving the gray that is the composite of the two.

And, again, we have these primary and secondary peaks each day that I showed before. They have to be the same. But the sectors differ quite a bit. The commercial building peak is in the morning and there really isn't a secondary peak. There's a big plateau in the afternoon. And so the secondary peak of the residential sector, when added with this commercial building load, drives that secondary peak up so that the gap between secondary and primary on each day across all the sectors is narrower than it is just for the residential load. So there's a synergy between the residential and commercial building sector that, in some respects, makes this issue even more difficult because you have two relatively similar peaks to this incremental load.

So going even further down into how it is that result was developed, this is just looking at the residential sector of that same previous slide but decomposing it down to individual end uses. Here, it's slightly different days. It's the day before the peak day and the day after, just so you can see what's happening from that progression across time. Clearly, what is being shown here is that space heating, in blue, is the largest single component. Water heating, in orange, is the second. And the other three really hardly matter.

Again, we have this bimodal pattern which, of course, has to be caused by these underlying end-use shapes themselves. And again, the same kind of idea that showed between residential and commercial building is showing up within the residential sector itself. The bimodal shape of a secondary peak in the morning and a primary peak in the evening is being somewhat mitigated by having the primary peak of water heating in the morning and its secondary peak in the evening. And so in the green line, that's the composite across the residential sector, that differential is muted somewhat.

MR. RIDER: Mike, may I ask a question here?

MR. JASKE: You may.

MR. RIDER: These shapes are translations of natural gas heater shapes; correct? Like you said you were keeping things -- you said you were using a multiplier to move it into energy and you're trying to keep the delivery of the outcome the same.

MR. JASKE: But --

MR. RIDER: I guess what I'm asking, is this just a translation of the natural gas profile into electricity profiles as if they were able to deliver energy at the same time and rate?

MR. JASKE: No. I think you're misinterpreting --

MR. RIDER: Okay.

MR. JASKE: -- what I said, so let me clarify.

MR. RIDER: Okay. Thank you.

MR. JASKE: That equal amount of energy service, that equivalence, is only on an annual basis. So we have natural gas consumption on an annual basis translated to electricity consumption on an annual basis. And then that electricity is spread across all the hours of the year with electricity load profiles. We did not make use of natural gas load profiles at all. And for some electric applications, it's probably very clear that the load profile of gas and electric are going to be different, if not across the seasons, at least within a day. And I'll get -- I'll elaborate on that point a little bit later. But, basically, you don't run a space heating heat pump the same way you run a natural gas furnace in your house.

MR. RIDER: Great. So that data that you're accessing from the HELMs and other previous sources are heat pump-specific load profiles?

MR. JASKE: These are generally not heat pump

profiles. And that is one of the areas of further work --
MR. RIDER: Oh.
MR. JASKE: -- that I'll get to later.
MR. RIDER: Thank you.
COMMISSIONER MCALLISTER: Yeah, Mike, I was just going to chime in here. So, I mean, it looks like -- so just on these substituted loads, we're adding, just gauging from the graphs here, you know, 8,000 megawatts of ramp a couple times a day, somewhere between 5,000, 6,000 to 8,000 megawatts of ramp over and above. I guess it would be nice to map onto, maybe you're doing this with the ISO, but map the specific load substitution, you know, substituted loads onto the overall load shape to see where they stack.
MR. JASKE: Voila.
COMMISSIONER MCALLISTER: But that's a lot of -- yeah.
MR. JASKE: Here's --
COMMISSIONER MCALLISTER: So I was jumping ahead to the next slide.
MR. JASKE: -- it's doing exactly that.
COMMISSIONER MCALLISTER: But that's -- I mean, I saw Delphine here earlier, there she is, but -- so I guess that leads to -- and maybe there's a punchline here

that I haven't scrolled down to yet, but --

MR. JASKE: Well --

COMMISSIONER MCALLISTER: -- how we can manage these loads so that we don't get these ramps? You know, to kind of Ken's point about the load shapes, in part at least, we could drive by policy. And maybe, you know, one goal that we should have here is to figure what policy would help smooth out these impacts.

MR. JASKE: Let me explain this slide and then I'll directly address your point.

So let me start with the orange line. The orange line is the hourly adopted forecast from the 2018 IEPR update mid-mid case for the ISO. So unlike the previous slides that were -- included SMUD and LADWP, this is just the three IOUs that contribute to ISO loads.

The blue at the bottom are the hourly incremental electric loads for just those three utilities. The gray at the top is the summation. So you can see that we already had kind of a bimodal pattern but it's not quite as crystal clear as it in the incremental load. And what the incremental fuel substitution does is make that underlying base forecast more bimodal and sharper peaks at those morning and evening maximums than was the baseline forecast.

So here on the peak day or peak of the electric load impacts, in January that 12,500 or so megawatts just within the ISO service area, added to about 31,000, 32,000, something like that, results in about 44,000 megawatts of that hypothetical future day with a lot of fuel substitution. That compares to the summer peak of about 45,000 in 2030 in that case. And so we're very, very close to becoming a winter-peaking utility if nothing is done.

And so to your question, what could be done? Well, the supply side of the system is going to have a really hard time satisfying that gray line. And so one idea -- well, and so is that truly the right shape? We're not confident that's the right shape yet.

And so the staff is embarking on a whole parametric study of heat pump performance in different climate zones with different vintages of buildings, with different thermal integrities and different consumer behaviors, set points and so forth, and try to better understand how a heat pump space heating future may or may not be the same as what we're estimating here in blue right now, but it's something like that.

And if -- and it may well be the case that it continues to line up with these other points at which the base forecast is peaking, so there may be a shape something like that gray one. And if that's the case, perhaps there's a role for demand response, either programmatic or automatic, rate induced, you know, some combination of those that will help make this a shape that's easier for the grid to supply because solar is not -- at the end use, behind-the-meter level, is not going to do anything to these particular morning and evening times in the winter. There's just --

COMMISSIONER MCALLISTER: Yeah. I mean, that morning peak is extra, you know, x-thousand megawatts at, you know, 5:00 a.m., 5:00, 6:00, 7:00 a.m.

MR. JASKE: Correct.

COMMISSIONER MCALLISTER: Yeah.

MR. RIDER: I think that would be a valuable update --

COMMISSIONER MCALLISTER: Yeah.

MR. RIDER: -- with the profiles because the BTU inputs on heat pumps is so much lower than natural gas, it takes a lot longer to heat up.

MR. JASKE: Yeah.

MR. RIDER: So, you know, that's the mismatch that I was a little -- I mean, you're working on it. It sounds like you're doing a good job and heading the right way with the profiles but --

MR. JASKE: Well, and we've actually looked at some residential building simulation model results and they are more bimodal and less uniform than common thought heat pump performance is going to be. And we're not quite sure why we're getting that result but it's going to be an interesting challenge to try to really understand how heat pumps work in a multiplicity of thermal integrity building.

COMMISSIONER MCALLISTER: Yeah. I mean, you might want to -- I mean, that's -- again, you know, I'll often say this, but it goes back to the building shell in a lot of ways because that gives you more flexibility, is when you run the darn thing; right? Whereas, if you don't --

MR. JASKE: Right.

COMMISSIONER MCALLISTER: -- at least on the heating side, on the space heating side and, you know, the space cooling side.

So, also, I guess I would encourage, you know, a diverse, I'm sure you're having this, but a relatively in-depth discussion about what the different parameters for that might be? Like, you know, we might want to consider, you know, what does oversizing a heat pump look like? Does that give us more flexibility in recharging quickly when we have the energy available, instead of running, you know, the heat pump, a smallish heat pump for longer, that kind of thing?

MR. JASKE: Um-hmm.

COMMISSIONER MCALLISTER: But we need that flexibility, so how can we build that in?

MR. JASKE: Yes. That's --

MR. RIDER: And one last thing is the northwest, the folks in the northwest, they talk about this, where we'd clearly already be, I mean, probably at 40 percent of peak winter load is the concern of performance deterioration in cold weather. And then your peak gets really peaky because the efficiency of the heat pump falls off.

So, I mean, it's going to be tricky, especially given we just looked at the overall forecast, and trying to get to the peaks correctly, the winter peaks are going to be extra tricky in, what was it, a quasi AB 3232 -- it's not quasi -- pseudo --

MR. JASKE: Yeah. And the --

MR. RIDER: -- AB 3232 world.

MR. JASKE: -- and the points that Nick was making that you were questioning him about concerning weather-normalization of summer peaks, I mean, we don't have any experience in understanding this kind of winter peaking and what kind of weather, you know, is driving the outcomes that are more severe. It may even be the case that the cold temperature itself is not the most severe predictor of bad -- of maximum loads. It could be that something that's not quite as severe but has a lot of cloud cover that kills, you know, solar, you know, and ramps up the commercial building side of things, you know, is the worst, or prevents batteries from recharging to mitigate some of this by load clipping.

So there's a long way to go to really bring ourselves to the point where we have confidence in the shapes and how to deal with moving them around as a result of programs.

All of what I've said so far has been focusing on wintertime. I just wanted to draw your attention to the fact that there are summer and, of course, non-summer impacts as well. This is showing the maximum summer load defined to be from June 1st to the end of September. And you can see here that we are very close to the end of September. These three days that are being shown, this is a little over 4,000 megawatts in the middle day. There are peaks in the morning, not in the evening and, again, has that very bimodal shape. So that's about a ten percent increment relative to the kind of peaks we were just talking about in Nick's presentation.

So what did we learn from all this?

We certainly got a relative sense of the importance of the different sectors and end uses from an annual energy and hourly load perspective. We certainly learned that these winter results are highly sensitive to the space heat profile but we're not so confident that we really understand that we have a good space heat profile yet.

We've learned that summer incremental load increases aren't trivial in a commercial building -- well, I guess I didn't get into that. The commercial building is really more important in the summer period.

But we're not fully addressing some residential air conditioning load issues yet because if we're replacing gas space heating with heat pumps, there's probably some gas space heating dwellings that haven't had air conditioning or only have room air conditioning that are going to have an air conditioning capability. And that exercise -- that capability is, presumably, going to be exercised, at least on peak or near-peak days. So there's some incremental residential air conditioning load that we may yet need to track down and address.

And, of course, as I showed in that one chart about the alternative assumptions about relative efficiencies between the gas side and the electric side by end use, those were averages. This -- a real limitation of this project was only looking at things at the end-use level.

We really need to understand the technologies within an end use and are there variations in particular slices of gas consumption that are the first ones or the best ones or the least -- or most cost-effective ones to displace and what do we replace them with? And how to match those up from a program design perspective to actually accomplish, you know, these hypothetical penetration levels is something that we will be exploring more in the AB 3232 project because we are having Navigant help develop a tool that is at the sub end-use level, so we can really understand at the technology level what the costs and the ramifications are.

I've said AB 3232 several times. This isn't an AB 3232 study. It's not really addressing the primary focus of a GHG emission reduction. This is just the fuel substitution portion of things. But we think that's, by far, the dominant component of GHG emissions, so this is at least in the right ballpark.

There's a lot of limitations here. I won't repeat them in the interest of time.

And we are working with Navigant Consulting to develop a better impact projection capability. We are hoping to bring that into the formal AB 3232 project somewhere around the first of the year or a little bit after that. There's some interesting analysis of technology cost and performance there. A number of other issues that are extra challenges to high levels of displacement of natural gas. And I think I've already said what needs to be said about this parametric space heat load profile project.

In conclusion, these scenario projections are interesting but they're too uncertain to include in official Energy Commission managed demand forecasts, so that's why this is just an exploratory study in parallel to but not merged into those managed demand forecasts.

And with that, I am finished. And if there are any questions --

COMMISSIONER MCALLISTER: Yeah.

MR. JASKE: -- I'm available.

COMMISSIONER MCALLISTER: Yeah, I have a question.

So I guess just on the timeline, building on this a little bit, you know, it's not an AB 3232 study, but I guess how is this work -- this work seems critical for AB 3232. And so how are you going down these parallel tracks and crosspollinating with that team that is doing the AB 3232?

MR. JASKE: We're talking with them every week as they're working on developing the project. So this was -

- their project scope was sort of designed after most of this had already been done. And so this technology-specific point I've made a couple times about understanding, you know, the individual gas technologies and how they might be appropriately displaced with electric ones is something that they've already largely completed. And they're building a tool now that will -- at that sub end-use level, you know, respond to sort of what-if scenarios. And that will, in turn, reveal by adding in the GHG emission consequences, sort of this whole idea of a GHG-per-dollar --

COMMISSIONER MCALLISTER: Yeah.

MR. JASKE: -- curve that could be constructed by looking at all of that sub end use diversity. And from that, we'll have a bunch of questions for policymakers about how it is we actually can choose to pursue particular things that are the most cost effective to pursue and design programs to go out and cause that to start happening?

COMMISSIONER MCALLISTER: Yeah. That's great. I guess -- and then I would -- specifically, right, we have SB 49 which allows us some inroad to looking at appliance flexibility in greenhouse gas emissions. And, you know, I think if some recommendations could come out of this work, sort of cycling, you know, the virtuous cycling between -- or virtually cycling between this work and the 3232 work, you know, maybe we can figure out a way to -- maybe we can distill some recommendations for SB 49 implementation that can help us get a handle on communicating with controlling these electric heating loads in a way that makes sense and is cost effective for customers, et cetera, et cetera. I think that's going to be really critical.

So thanks. Thank you. I really appreciate all this work. This is a really good start.

MR. JASKE: Thank you.

VICE CHAIR SCOTT: It's very good stuff.

I would also add, I was kind of, Mike, as you were speaking, hearing some possible EPIC projects --

COMMISSIONER MCALLISTER: Yeah. Exactly.

VICE CHAIR SCOTT: -- if we don't have any already, especially with the double peaks and the potential impacts that those might have on the grid, and even looking into what the space heat load profile looks like are things, maybe, that the EPIC team can help with, as well, so it's more of a comment than a question.

Any other questions from the dais? All right. Great.

Thank you for you thorough and interesting presentation.

So we are now going to turn to the public comment portion. I will give the team just a second to get our timer up. And I will get my blue cards here.

And let's see, maybe while I'm waiting for them put up the timer, I'll just make a couple of observations from today's workshop.

I mean, I think that this was, as usual, sort of chalk full of useful data that it takes some time to really wrap your brain around and dig into. I think the level of sophistication and the robustness of the analysis that our team is doing is, really, is pretty incredible. And it's also just really important, you know, on the transportation side, the natural gas side, the electricity side, in a time when so many of our variables are changing; right? So we've got that behind-the-meter PV, we're looking at electric cars, we're talking about peak shifts, we're talking about fuel switching, I mean, all of these things. And then we're looking at them in a very granular way where we're moving, you know, from annual to monthly to weekly to hourly, and then across the state and trying to get more specific regionwide. And then on top of all of that, climate is changing, so it's, you know, it's a lot going on.

But I feel like the team has done a very nice job taking a lot of complex data and assembling it in a robust way that the state can then take action on.

So, okay, I see that we're ready.

Did anybody else want to make comments before we jumped in? Okay.

So public comments. I just have a few. The first one is V. John White, followed by Ken Schiermeyer. I might have butchered Ken's name. Sorry about that.

Oh, you have to push your button there.

MR. WHITE: Very interesting day today to cover a lot of ground. As you said, a couple of points.

I wanted to go back to this morning to the energy efficiency cost effectiveness conundrum. This is a problem that's not getting solved at the PUC, okay? We're missing energy efficiency investments that, in light of Dr. Jaske's -- Mr. Jaske's analysis, would be very, very valuable, okay?

One thing I was going to suggest is to have the PUC have Mr. Jaske's presentation in their Aliso Canyon phaseout strategy and maybe have a scenario of what would it take to get rid of Aliso Canyon by the time the Governor had asked it to be shut down? But the cost effectiveness of energy efficiency needs to be overhauled and it needs to be done this next year.

Secondly, I think the question of load growth needs to be forefront in our thinking. We have lived in an era for the last 50 years of flat load growth and that's starting to change. And as a consequence, we're starting to get off in our projections. The PUC is having us revisit the once-through cooling deadlines because we misjudged the capacity needs, okay? And so that's a telling example.

In Oakland, to give an example, they did a very fine analysis to get rid of their peaker and add some transmission and some storage. It turns out there's 100 megawatts of load growth in the Port of Oakland between the baseball stadium, between electrification.

And so we've got to be conscious of these interactions. And this agency does a better job of breaking through the silos but those silos still remain.

Briefly on hydrogen, I think you need to rethink the business model that we have with regard to stream reformation of natural gas and really push us ahead to renewable hydrogen on a more distributed basis.

In case you didn't know, this summer, we had almost a total blackout of hydrogen fuel supply in Northern California and it's not helped the market for the light-duty vehicles. Heavy-duty vehicles, I think, are very important for hydrogen, so it's important to get that right.

Lots of things to talk about today that I could go on with but I'll leave it at that. And thank you for a very good presentation and we'll hope to have some opportunity to comment in the future.

Thank you.

VICE CHAIR SCOTT: Great. Thank you.

Next we have Ken S. I will let you get your name right when you come up. And you're followed by Delphine.

MR. SCHIERMEYER: Thank you. It's Ken Schiermeyer. And I'd like to, first of all, thank the CEC staff for working hard on this forecast. And we appreciate the collaborative effort that they took to go over all the components of the forecast throughout this process. And we look forward to working with them over the next couple weeks to continue that.

My comment is about we didn't talk about community choice aggregation in the forecast but that's what my comment is about, of including new CCAs in the forecast, particularly the load-serving entity forms.

For SDG&E, we're expecting two new CCAs representing eight cities to start service in 2021, and so this will be a big change for us, where we have one city currently that is less than one percent of our load, and these eight cities will combine to be over 50 percent of our load, and so it's a big change for us.

The deadline to file the Implementation Plan with the PUC is December 31st of this year. And this may not give the CEC much time to, you know, do something about that, to include it in the forecast, but I'd like to make the CEC aware of this potential. And we'd also like, if possible, to include them, you know, if they do file.

VICE CHAIR SCOTT: Thank you.

Delphine is next. And that's the last blue card that I have.

MS. HOU: All right. Thank you. This is Delphine Hou from the California Independent System Operator. Thank you, Commissioners, and for your time.

I also want to thank and congratulate the whole CEC team. Nick, Cary, Siva (phonetic), Matt, you guys have been incredible, very responsive. We're thankful for the incredible job they've done and responsiveness to feedback.

So I'll make a couple of points in reaction to what we heard today.

First of all, we definitely agree with Staff's assessment that it seems like SCE and SDG&E peaks seem a bit on the low side. So we do encourage the IOUs, and then to Ken's point, maybe the CCAs to step forward to kind of verify that and kind of comment on what they're seeing in their own territory.

I also want to commend Sudhakar for his excellent work on behind-the-meter storage, very difficult, very groundbreaking. We do know that, anecdotally, we've heard very similar things to what he has mentioned.

And on the transmission side, we're struggling with it as well. Battery is very new. We have very limited amounts operating at the moment. And we're also seeing a big disconnect between what we've optimized the batteries to do in the modeling framework and what they're actually doing. So even for us, we are learning as we're going. And what we're, in fact, doing is trying to add in an additional cycling cost because we think that's probably what's missing.

And I think Sudhakar is definitely on the right path in trying to figure out what is motivating the usage of behind-the-meter storage which I think will be very different than the transmission side? So we commend him for that great work.

Also, we commend and are very grateful to Mike Jaske for, once again, being a thought leader here and otherwise, for taking the lead on fuel substitution. We're very grateful that he's thinking forward ahead of the curve to, at minimum, get us to a good methodology so that when it really comes, we hit the ground running. We're seeing it as well. But again, you know, CAISO takes the forecast from the CEC and so we're sort of on the end of the process. So we're glad to be working with Mike and the CEC at the beginning of it.

I will also note, at the end of the conversation and back and forth you had with him is not only would you see less solar in the winter period, but you would have less capability to charge storage, and that's what concerns us as well. As we become a more storage-heavy system, we already have instances where we have, you know, four to five days of cloud coverage, so the question is how do you charge those batteries, either existing ones that are coming on, or even the autonomous option that we're also expecting?

So those are things we're all thinking about. And we're very thankful that the CEC is ahead of the curve and thinking about it as well.

So thank you very much and congratulations to the team.

VICE CHAIR SCOTT: Thank you.

Those are all the blue cards I have in the room. Let me turn -- and if you have a business card that you would please give our Court Reporter, he'll be very happy to make sure he gets your name spelled correctly in the transcript.

Let me turn to my team and see if we have any comments on the WebEx?

MR. COLDWELL: No. We don't have any.

VICE CHAIR SCOTT: Okay. They're telling me, no, we do not have comments on the WebEx.

So with that, public comment is closed, and I will turn to Matt to wrap us up.

MR. COLDWELL: Okay. Well, thank you.

(Colloquy)

MR. COLDWELL: Just some quick next steps to mention.

Written comments are due December 16th. Information for using the e-filing system is here on this slide, along with the docket number that goes along with this proceeding, and then the instructions.

And other than that, I think we're --

VICE CHAIR SCOTT: That's everything. So comments due December 16th. You've got your information there on the slide.

I also want to say thank you very much to our staff for excellent analysis and great presentations today. And we look forward to hearing from the public.

And with that, we're adjourned. Thank you everybody.

(The workshop concluded at 4:00 p.m.)

REPORTER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and

place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

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 15th day of January, 2020.

PETER PETTY
CER**D-493
Notary Public

CERTIFICATE OF TRANSCRIBER

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 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.

I certify that the foregoing is a correct transcript, to the best of my ability, from the electronic sound recording of the proceedings in the above-entitled matter.

Martha L. Nelson

MARTHA L. NELSON, CERT**367

January 15, 2020