# DOCKETED

| | |
|---|---|
| **Docket Number:** | 23-IEPR-03 |
| **Project Title:** | Electricity and Gas Demand Forecast |
| **TN #:** | 252565 |
| **Document Title:** | Transcript on 8-18-23 for IEPR Commissioner Workshop on Load Modifier Scenario Development |
| **Description:** | N/A |
| **Filer:** | Raquel Kravitz |
| **Organization:** | California Energy Commission |
| **Submitter Role:** | Commission Staff |
| **Submission Date:** | 10/10/2023 4:09:39 PM |
| **Docketed Date:** | 10/10/2023 |

STATE OF CALIFORNIA

CALIFORNIA ENERGY COMMISSION

| | |
|---|---|
| In the matter of, | ) |
| | ) Docket No. 23-IEPR-03 |
| 2023 Integrated Energy Policy | ) |
| Report (2023 IEPR) | ) Re: Load Modifier |
| ______________________________ | ) Scenario Development |

**IEPR COMMISSIONER WORKSHOP ON**

**LOAD MODIFIER SENARIO DEVELOPMENT**

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

Friday, August 18, 2023

10:00 A.M.

Reported By:
C. Caplan

APPEARANCES

Commissioners and Dias Members

Siva Gunda, Vice Chair

Ben Wender, Adviser to Commissioner Monahan

CEC Staff

Stephanie Bailey, CEC

Quentin Gee, CEC

Raquel Kravitz, CEC

Presenters

Alex Lonsdale, CEC

Mariko Geronimo Aydin, Lumen

Onur Aydin, Lumen

Nick Fugate, CEC

Ingrid Neumann, CEC

Ethan Cooper, CEC

Jesse Gage, CEC

Aniss Bahreinian, CEC

Maggie Deng, CEC

Public Comment

Santosh Lamichhane, Pacific Gas & Electric Company, PG&E

Alex Pusch, Southern California Edison, SCE

Claire Broome, 350 Bay Area

INDEX

INDEX (CONT.)

P R O C E E D I N G S

AUGUST 18, 2023 10:00 A.M.

MS. BAILEY: All right. Good morning everybody. I'm going to give just a moment for everybody to log on and then we'll get started.

Okay. All right, well good morning. Welcome to today's Commissioner Workshop on Load Modifier Scenario Development. I'm Stephanie Bailey with the Integrated Energy Policy Report Team or IEPR for short, here at the CEC.

This workshop is being held as part of the CEC's proceeding on the 2023 IEPR. And today we're doing a hybrid workshop. We're using Zoom and we're also meeting in person. So, for those in the room today, videos of the presenters and Commissioners on the dais are being broadcast over Zoom. And everything displayed over Zoom is also being shown on the screen in the room.

This workshop is being recorded and a recording will be linked to the CEC website shortly after the workshop and a written transcript will be available in about a month.

To follow along, the schedule and slide decks have been docketed and posted on the CEC's IEPR webpage, and hardcopies of the meeting schedule should also be available for in-person attendees.

Attendees can provide comments on the material being discussed today in a few ways. Can definitely make comments during the public comment period at the end of the day. And please note that while we look forward to hearing public comments, we won't be responding to questions during the comment period. And those comments will be limited to three minutes or less.

For those in the room who'd like to make a public comment, you can raise your hand at the appropriate time and staff will direct you to the correct spot.

We'll also be taking public comments from remote participants, so you can use the raise hand function in Zoom, which looks like a high five, or *9 on your phone during the public comment to let us know you'd like to comment.

And written comments are welcome and instructions for providing those are in the workshop notice. And those are due by 5:00 p.m. by September 1st.

So, with that I will turn it over to Vice Chair Gunda for opening remarks. Thank you.

VICE CHAIR GUNDA: Thank you very much. Welcome everybody. I think we have participants online, just want to begin by thanking the IEPR team for setting the stage for today's important discussion. Also want to thank all the public participants. You know, the IEPR is only as good as the public participation and engagement, and all the perspectives we hear along the process. So, thank you, everybody, for taking the time to both join here in the room, but also online.

I want to just share a couple thoughts at the high level. We had our first segment of the forecasting workshop two days ago. A really helpful discussion on the inputs, especially the econ demo. Inputs, but also thinking through what the forecast has been and what it's going to be moving forward and the evolution of that. You know, it can be understated how important the forecasting process is for the broad resource planning for the state, the reliability planning, and thinking through various policy options.

And I just want to thank Nick, and Heidi, and all the forecasting team for all the work they have been doing to just move the forecasting from a single point estimate, which worked for a while, to this kind of policy laid scenario development, which helps both to think through the resource planning, but also helps back some of the policy decisions that we have to do.

So, thanking the team and looking forward to the discussion.

So, then I'll pass it on to Ben Wender. I want to acknowledge that Commissioner Monahan is the Lead Commissioner. I'm supporting her on the IEPR this year. She's not able to join today, so Ben's filling in for her. And Commission McAllister will be here at some point. Thank you.

MR. WENDER: Thanks Vice Chair Gunda. For those expecting to see Commissioner Patty Monahan, she sends her regrets. She's a little under the weather. And I have the pleasure of sitting up here with the Vice Chair and learning from our esteemed forecast team.

Couldn't agree more with the incredible importance of the demand forecast and really being the tip of the spear, and helping our state achieve the transition to zero emission transportation systems, and decarbonizing electricity supply while maintaining reliability, affordability, and increasing our resilience to a rapidly changing climate.

You guys have done a number of exciting improvements to the forecast framework, to the models and assumptions that are put into it. Really excited to hear about those advancements today, and appreciate the opportunity to learn from all of you.

So, with that, I look forward to jumping into the discussions.

VICE CHAIR GUNDA: Thank you, Ben. With that, I will pass it to Alex to start it. Or, Heidi, I'm sorry.

MS. JAVANBAKHT: Good morning everyone. So, our first presenter today is Alex Lonsdale. Alex is the Supervisor of the Distributed Generation Forecast Team. And he will be talking about behind the meter -- the behind-the-meter self generation forecast update.

MR. LONSDALE: All right, good morning everyone. As Heidi said, I'm Alex Lonsdale, Acting Supervisor for Demand Forecasting Unit and Supervisor for Distributed Generation Forecasting to support the 2023 forecast.

Next slide. Before I hop into forecast-specific updates, I do want to highlight changes to our historical behind-the-meter distributed generation estimates.

Next slide. For the 2023 energy demand forecast we have refreshed our historical behind-the-meter solar PV and storage cumulative capacity estimates.

Refinements include shifting to a single data source for behind-the-meter solar PV and energy storage capacity information, as well as improving and expanding data cleaning tools. Refinements will be discussed in detail on the following slides.

Next slide. Previously, CEC staff relied on three data sets to estimate historical cumulate behind-the-meter solar and storage energy capacity.

Historical behind-the-meter energy storage capacity was estimated from a combination of CPUC's Self Generation Incentive Program, or SGIP, and Rule 21 interconnection data that CEC collects.

This year, staff has transitioned to utilizing the utility distribution company, or UDC, interconnection data, which CEC collects under the California Code of Regulations, Title 20, to estimate historical cumulate distributed generation capacity.

This dataset includes a list of all interconnected energy systems located within each utility service territory.

The data we collect from the UDC, or utilities, includes unique formatting or data entry errors in some cases, which must be addressed to estimate historical distributed generation capacity.

Previously, staff manually cleaned the utility interconnection datasets to resolve data issues.  This involved manually going into Excel workbooks submitted by the utilities, looking for errors in interconnect approval dates, technology types, and the interconnection agreement type.

For the  2023 forecast, staff have developed data cleaning scripts to improve accuracy of our estimates. The following slides will highlight how our revised historical data cleaning process has impacted historical distributed generation cumulate capacity estimates.

Next slide. And now that I've introduced changes to the historical capacity estimation process, I will present charts which reflect current and past forecast cycles estimates of historical behind-the-meter solar adoption.

Next slide. Starting with a low resolution comparison, in the following chart we have the 2022 cumulative capacity estimates, the gold line, and the 2023 forecast cycle cumulative capacity estimates, the dark blue line.

Y-axis units are AC nameplate capacity cumulate megawatts, and the X-axis is calendar year spanning from 2004 to 2022.

For the 2023 energy demand forecast we estimate there's about 14,220 megawatts of behind-the-year solar capacity by end of calendar year 2022.

You'll note overall to the historical period that our 2023 estimates are lower than the CED 2022. In 2021, our cumulative capacity estimates are roughly 7 percent lower than last year.

Next slide. The following chart format is the same. However, this chart is specific to a majority of the CAISO footprint. These estimates cover the PG&E, SCE, and SDG&E service territories.

In addition, you'll note there's an additional line in this chart, the light blue dashed line, which is representative of the DG stats cumulative capacity estimates. DG stats includes public reporting of historical cumulative capacity estimates per distributed generation within the IOU service territories. For solar this includes NEM interconnection agreements.

Overall you'll note that our cumulative capacity estimates for the 2023 forecast are well aligned with the DG stats cumulative estimates. However, you'll not that our estimates are slightly higher than DG stats, as CED estimates include NEM and Rule 21 non-exporting interconnection agreements.

In calendar year 2022, you'll note that our cumulative capacity estimates are 244 megawatts higher than the DG stats estimate, which is a percent difference of about 2 percent.

Next slide. The following chart again presents the behind-the-meter solar adoption for PG&E's service territory in this case. The three same lines exist in this chart.

There is a table to the left of the chart which summarizes cumulative capacity. You'll not again that the same patterns exist in this dataset, where our 2023 estimates are lower than the 2022 forecast and well aligned with the DG stats estimates.

Next slide. The following chart is specific to the SCE service territory. Again, similar patterns exist in this dataset, where our 2023 forecast estimates are lower than the 2022 forecast.

Our calendar year 2022 estimate are about 47 megawatts higher than the DG stats estimate, which is a percent different of about 1 percent.

Next slide. Finally, we have the SDG&E service territory. You'll note that of the charts that I've presented today on behind-the-meter solar that our cumulate capacity estimates are most narrow or dissimilar across these three datasets.

Our calendar year 2021 estimates, this year are about 10 megawatts lower than the 2022 estimates. And our calendar 2022 estimates, for the 2023 forecast, are roughly 25 megawatts higher than the DG stats estimate. This is a percent difference of about 1 percent.

Next slide. That concludes today's overview of historical behind-the-meter solar adoption, changes for the 2023 forecast.

Next, I will present updates to historical behind-the-meter storage adoption.

Next slide. Before I present charts, I do want to note a couple things. The previous CED estimates, as mentioned previously, are based off of the SGIP and Rule 21 interconnection data. And the 2023 estimates are derived from utility interconnection datasets.

The CEC staff have reached out to IOUs and the CPUC to resolve discrepancies shown in the following slides. If there are updates, staff will provide these as soon as possible in an upcoming workshop.

Next slide. The first chart depicts behind-the-meter storage adoption for the SDG&E service territory. Overall you'll note that our 2023 forecast estimates are well aligned with the DG stats cumulative capacity estimates.

Whereas our 2022 forecast estimates are much lower in the historical time series. This is mainly a product of shifting away from the SGIP and Rule 21 data, and capturing capacity from the interconnection datasets.

Next slide. Taking a closer look at the cumulative behind-the-meter storage capacity across SDG&E's service territory, you'll note that our residential cumulative capacity this year is much higher than the 2022 forecast. Whereas our nonresidential cumulative capacity estimates are well aligned with the 2022 forecast.

This is mainly a product of what is captured in the SGIP data, as well as the Rule 21 interconnection data.

Next slide. As I mentioned before, we're still working through some data discrepancies. And you'll notice that our cumulative capacity estimates for the 2023 forecast are in fact higher than both DG stats estimates and the 2022 forecast.

Specifically, our calendar year 2022 estimates are about 49 megawatts higher than the DG stats estimate.

Next slide. Taking a closer look at the sector level cumulative capacity, you'll note that our -- again, on the residential end, our cumulative capacity estimates are much higher than what we captured in the 2022 forecast. Again, shifting to utilizing the interconnection datasets submitted by the utilities.

On the nonresidential end, we have a lot more cumulative capacity captured from the interconnection datasets when compared to our 2022 forecast and the DG stats estimate.

Next slide. Finally, we have cumulative

capacity estimates for the PG&E service territory. You'll note overall, again, that our estimates are higher than last year and are in fact higher than the DG stats estimates as well.

Next slide. Taking a closer look at cumulative capacity estimates by sector, you'll note that our residential estimates again are much higher than last year. However, our 2023 forecast cycle nonresidential cumulative capacity estimates are lower in calendar years 2020 and 2021. This is likely a product of records in the SGIP or Rule 21 data, where customer sector is not provided and it was possibly misclassified.

Next slide. This concludes my overview of historical cumulative capacity updates for the 2023 forecast cycle.

The following slides are going to capture improvements we made to forecasting distributed generation for our 2023 forecast.

Next slide. For the 2023 forecast, the CEC has adopted NREL's dGen model. Energy Commission staff worked with NREL over the last year to develop a California-specific version of their model. CEC will use the staff to forecast adoption of standalone PV, as well as PV + storage.

Next slide. But more specifically, what is the dGen model? Broadly, dGen model is a market penetration model which simulates adoption of distributed generation technologies.

It includes a market diffusion model that determines rates of distributed generation adoption and maximum market share from modeled economic potential, including net present value and payback period.

As more consumers adopt distributed generation technologies in the model, there are in fact fewer available adopters in the future years of the model.

The California-specific dGen model includes key policy updates, including the net billing tariff, as well as the investment tax credit.

Next slide. As folks are probably aware, the CPUC adopted the Net Billing Tariff in late 2022 as a replacement to Net Energy Metering, NEM 2.0. This went into effect for interconnection agreements beginning of April of 2023.

Electricity exported to the grid under this tariff is compensated in accordance with the Avoided Cost Calculator. And the ACC values excess energy exported to the grid based on marginal costs of providing electric service to customers.

The PG&E and SCE customers receive additional credits to make payment reductions more gradual. And this is referred to as the glide path in the tariff.

Next slide. Federal government extended the ITC as part of the Inflation Reduction Act in August of 2022.

VICE CHAIR GUNDA: Just a quick question.

MR. LONSDALE: Of course.

VICE CHAIR GUNDA: Just a quick question on the previous slide. Isn't there a provision in that billing tariff for low-income as a specific provision? How are we -- are we taking that into account?

MR. LONSDALE: So, from a modeling perspective we don't have specific -- we haven't set up our inputs and assumptions to have a break out of care versus non-care customers. However, we do have a version of the model that we are working to learn about and build out assumptions for. We have income bracketed, inputs and assumptions.

So, there would be a way, yes. There is a provision and would be able to, in other scenarios, simulate adoption for this low-income bracket where there's a change in the export rate that's how the excess energy is compensated.

But for our key tool that we'd be using for our 2023 forecast, our baseline, that is not something that is captured in the inputs and assumptions.

VICE CHAIR GUNDA: Do we -- we can talk about this separately or follow up but just, you know, just understanding how big of a magnitude that could be.

MR. LONSDALE: Sure.

VICE CHAIR GUNDA: It would be good just to have a flag on as we move forward in the public setting.

MR. LONSDALE: Absolutely.

VICE CHAIR GUNDA: Thank you.

MR. WENDER: Yes, maybe I can ask one question since we're on the net billing tariff changes, and probably worth thinking about this, and don't have to answer it now. But one of the things we saw in an earlier IEPR workshop this year was the state's IOUs showing the number of applications through Rule 21 that they're receiving and just this, you know, massive increase in Rule 21 applications associated with the phase in of the net billing tariff.

And I think we're thinking through how that large step function increase in applications manifests in our forecast and in the historical tracking. So, I don't know if you have thoughts or answers on it now, necessarily, but something we'll have to put a pin in and think through as the forecast continues.

MR. LONSDALE: Yeah, thanks for that comment, Ben. I do have some initial thoughts and I do think that our model is not going to be able to capture this consumer adopter behavior where we're switching over from one tariff to the next.

However, I do think it's something that we need to keep an eye on in our forecasting period. And if we are able to gather data that it's reflective of sort of interconnections that are -- we are expecting, or the level of interconnection that we're expecting that we adjust our forecast to capture the spike of adoption, or the spike of installations resulting from a shift to a new tariff.

VICE CHAIR GUNDA: While we are on the questions, I just want to ask one more and we'll be done. So, the when do we, in the process, capture community solar storage and how do we capture that, at all?

MR. LONSDALE: Community solar would be not specifically broken out as an agent in our model. So, that's probably not something -- like the economics of the community solar is probably -- well, is not something that would be simulated.

Our model is more looking at individual adopters, individual commercial adopters, or individual residential installation. That's something I think we need to think through in more detail at a separate meeting, and discuss in more detail. Just because it's not something our model is configured for is the community solar installations.

VICE CHAIR GUNDA: Yeah, so just on that, just a recommendation for us to kind of put the pin here. At the end of the day we are looking at sending the results to PUC, and then PUC is kind of thinking through others and then they're thinking through the supply side, right, the IRP.

MR. LONSDALE: Uh-hum.

VICE CHAIR GUNDA: To the extent that we are going to have the community solar and storage become a larger portfolio, I think you'll begin to have significant adder, right, slowly kind of creeping, to if it's not accounted for somewhere.

So, to the extent that if it is accounted for, it will be good to have it on the public record. If it is not, kind of just setting the stage on where in the process we would imagine incorporating that on the long term would be really helpful.

Because I would imagine the push for community solar and storage both from the Legislature, and kind of broadly the advocacy we'll begin to see that portfolio grow, and just thinking through that.

MR. LONSDALE: Absolutely and I think that's an important flag to raise. Just with our model, how it's set up, as I mentioned, it's not something -- an agent-based model in terms of residential end consumption. The model is set up to think of individual adopters, what is the economics of installing solar in my home. And I think that's an interesting paradigm shift where you're now thinking about what if this economics was based upon a group of individuals that were installing solar.

Now, I do want to mention, though, for new solar installations we do have a separating forecasting tool that I'm going to highlight in future slides. The dGen model, which is what I'm describing here, and updates to the dGen model does not capture new construction build.

And so, that is something that's completely separate, where we model the impacts of Title 24, residential solar installations on new homes and commercial buildings exogenously from the dGen model.

So, there's some overlap there, but it's just thinking through would the solar installation be on the single home or would it be collectively installed and say the neighborhood, or nearby. So.

MR. WENDER: Yes, I was going to ask a similar, and partially overlapping, but interconnection applications through like the wholesale distribution access tariff, or distribution connected resources that aren't necessarily behind the customer meter could fit the community solar.

And so, I'm not sure where within our various forecasting efforts that fits.  But is wholesale distribution access tariff interconnections reflected in the datasets you get from IOUs or is it not included in those?

MR. LONSDALE:  So, WDAT tariffs are included in the interconnection data, but we do not consider it as behind-the-meter distributed generation capacity because of how it's interconnected and interacting with the grid.

Like I said in the interconnection slides, the records that we're looking at are NEM interconnected systems, as well as the Rule 21 non-interconnected systems that are connected to the distribution system that are specifically built out to serve onsite load. That is what we're capturing.

All right, so I think investment tax credit. I'm just going to highlight that again.  For the 2023 forecast cycle we have captured the extension of the investment tax credit, which was extended in August of 2022 as part of the Inflation Reduction Act.  It's now extended through 2034 and incorporated in our forecast.

The IRA also -- or, the ITC tax credit extension also introduced a new tax credit for standalone storage installation. And just to highlight, the ITC provides a tax credit of up to 30 percent of installation cost for distributed generation.

Next slide. The staff have compared preliminary results from the dGen model to finalized 2022 forecast cycle results.

In the chart, shown here the Y-axis units are cumulative megawatts of capacity and the X-axis is calendar year spending from 2020 to 2035.

The green line is our preliminary dGen model projects, with inputs based on the 2022 demand forecast. The gold line is our 2022 energy demand forecast.

You'll note that the adoption trends from these forecasts are different, resulting in varying levels of cumulative solar capacity in intermediate forecast years. Whereas the long-term adoption in calendar year 2035 is very similar.

Preliminary dGen model results depict less growth and capacity from calendar year 2032 to 2035. There are a few key drivers for reductions in added capacity in the modeling work.

This includes the reductions and eventual expiration of the ITC Tax Credit. I haven't mentioned this, yet, but in the ITC, in 2033 and 2034 the tax credit is reduced from 30 percent to 26 percent and 22 percent, respectively, until it expires in 2035.

The pace of adoption, our market diffusion model's also controlled by year-to-year changes in economics. The maximum market share is determined by the level of economic attractiveness or the payback period that each agent is simulated to have.

Last, there a finite supply of existing solar access roof space that is modeled. Again, it doesn't capture new construction.

Throughout the forecast period there is a shrinking level of potential adopters as well, which impacts the level of adoption.

More insights will be provided when staff have prepared revised model runs with the forecast inputs to 2040, for the 2023 forecast cycle.

Overall, I would note that staff expects the net billing tariff to have a downward effect on solar adoption due to longer payback periods from lower compensation rates. Whereas the ITC extension would have an upward effect on solar adoption due to the tax credit.

Next slide. So, as I mentioned before, the dGen models is able to capture the adoption of paired storage, but it does not -- it is not set up to forecast standalone storage.

In the past, our long-term storage capacity projects were based on forecasted growth rates for solar PV. With the adoption, the dGen model staff are able to project the capacity from paired storage.

And so, what we've done here is we have had to set up a separate model to capture standalone storage. At the August 8th DAWG, staff had presented preliminary forecasting methods relating Lazard's levelized cost of storage estimates and historical storage installations.

Since that workshop, staff have worked to compile analysis from the SGIP historical storage installation costs using -- in conjunction with SGIP historical storage additions to develop a linear regression model.

Forecasting storage predictions are determined from project storage costs, which serve as an input to our regression model.

And in the chart, you can see here there is a plot of historical storage additions behind the meter, as well as the total eligible costs per kilowatt hour.

Next slide. To extend total eligible cost through the forecast period, staff used NREL's annual technology baseline data to calculate annual percent decrease in costs. In the chart you will note there are three lines.

The light green dashed line is the historical trends based on actual estimated total eligible costs, which is the red line. And then, the green line is the forecasted total eligible cost through the forecast period.

You’ll note that total eligible cost declined substantially from 2022 to 2023, which accounts for the introduction of the ITC standalone tax credit.

And at the end of the forecast period, in 2035 you’ll notice that the total eligible cost increased slightly in a result of the expiration of the ITC tax credit.

Our preliminary forecast results show annual storage capacity additions increasing 35 percent by calendar year 2040.

In comparison, results to our 2022 forecast will be available at a future workshop.

Next slide. We do have some updates to our Title 24 forecasting method, which I mentioned earlier. Staff forecasts PV installations due to Title 24 building standard separate from dGen. Standards require new buildings, both residential and nonresidential, to include solar PV installations.

Staff are working with the Standards Compliance Branch in the Efficiency Division to leverage certificate of installation data to more accurately estimate the capacity of compliance-based residential solar PV installations.

Staff will also be using updated Commercial Buildings Energy Consumption Survey, or CBECS, data to reflect the latest survey for 2018, which was released in December of 2022.

This survey is used to gather information on buildings, including the building type, the number of floors and tenants, which affects commercial PV requirements.

Next slide. That concludes my presentation today. I'd like to thank public participants, Commissioners and stakeholders for their attendance today. I would encourage folks to review the link provided here to our August 8 DAWG for more information. Thank you very much.

VICE CHAIR GUNDA: Yeah, Alex. First of all, thank you so much for helping move the changes in a very collaborative fashion. And I really appreciate the time you take to dig into details and being able to explain them to me.

So, I think for me it's kind of a couple of comments just as a flag, no more questions, then we can follow up.

At the top of your presentation or in the forecasting presentation it will be really helpful to the earlier points on depending -- you know, so we have the bulk side, you know, bulk grid storage and solar, which is on the supply side. Anything that the IRP does not capture in their process, where are we capturing different elements, right.

So, as you said, dGen is specifically for individual actors. So it's essential and commercial. But are there elements that are incremental to that, and if it all are they captured, where are they captured. Just having that slide for public's view would be really helpful.

And the second one, just on the -- kind of getting the clarity. So, what I took from the input data is we have historically overestimated solar and underestimated storage penetration, right. So, we are now kind of correcting that.

So, to me, if you overestimate solar, from a reliability standpoint hopefully we were planning for a deeper duck, duck curve. But, you know, I don't know. So, I think it will be helpful to understand the implications on the reliability. Right, so from these changes. Because it's like now moving into hundreds of megawatts and it's like when we're tight, it's really tight.

The last one is on your storage estimate solar and storage estimate. If you can open up your slide deck again, just I think four or five slides back.

The Preliminary Comparison of Models, that's the slide title. Okay, yeah. Great.

Just on this one, so again for the record what you were sharing is the dGen model is looking at the existing stock primarily, and the penetration of behind-the-meter solar and storage in the existing stock of buildings. Right.

And then, incremental to that, you know, we have the new buildings that you're coordinating with the Efficiency Division on Codes and Standards, and the implications of that. So, we have two parts.

So, on this specific element, I think we kind of discussed a little bit during our internal meetings. It will be helpful to understand. What I see here is kind of a tapering of a S curve at the top, right. So, by 2035 we are tapering about, you know, you 30,000 megawatts on the existing stock side.

So, just want to understand is that the total adjustable market, are we capping it? What's happening on that particular instance, right.

So, if I take every building in California, like existing stock, what's the total market and are we approaching the maximum penetration based on your model here would be helpful to have.

MR. LONSDALE: Definitely, we can provide slides or insights to that in a future workshop. I think part of it, again, isn't necessarily that we're capping on the total available roof space and what could be installed, it's that we're capping on the model's market share that is penetrated based upon the economics of installing solar.

So, that's something that we have to look into closer because you're assuming certain levels of market share adoption based upon different research that has been performed. And we're using NREL's baseline assumptions for payback periods relative to market share, and that's something that we need to look into closer, but we can describe in more detail.

VICE CHAIR GUNDA: That is great. I think, you know, what is that 32,000 megawatts, you know, compared to in terms of market share. Right. So, if we are saying the current economics based on the different policies we have and the market side, prices and all, we are going to cap at X amount of market share.

The immediate question beyond forecasting, right, on the policy side would be what can we do to increase that market share, or should we not, or should we, right. So, those are the kinds of questions in advocately (phonetic) this information will help shape, so would love to get that information on the record. Thank you.

MR. LONSDALE: Certainly.

MR. WENDER: Yeah, and I’ll jump in on the dGen model, which tremendous work getting that folded into the forecast, and starting to move to this kind of diffusion, S curve based adoption.

Is it really -- is adoption predominantly driven by payback or are there other factors within the model that influence an individual decision to adopt, you know, solar and storage?

And I guess the second question is are there continued reductions in the costs of these resources factored into the model or do they -- and how do those evolve over time?

MR. LONSDALE: Yeah, great questions, Ben. I’ll start with your second question about assumptions about system costs. So, in dGen model there are assumptions about technology costs. We leverage the annual technology baseline projections that are available on NREL’s website, but they are included in the model simulations for estimating the key economic parameters that are in fact influencing the adoption.

So, yes, as well the key drivers of this model are the economics of installing solar. This is the key drivers that are determining if the agents will adopt solar in the model.

Again, the key parameters being the net present value of the system that is presented and simulated through several years of owning the system, or the lifespan of the system, as well as just the overall payback period of that system.

VICE CHAIR GUNDA: Great, thank you. I think we could probably move to the next section. Just flagging that I -- Heidi, and everybody in the room, I need to step out a couple of times from the meeting and I’ll hand it off to Ben. I need to jump out at 10:45 and I’ll be back. And I need to jump out at -- you know, thank you.

MS. JAVANBAKHT: Okay. And before we jump into the next presentation I just want to note with our schedule for today we’re taking Q&A from the attendees after all of the presentations this morning. We’ll have more Q&A time during the afternoon session and between presentations, and then the public comment period is at the very end of the day, approximately 4:15.

Okay, with that I'm going to turn it over to Mariko Geronimo Aydin, with Lumen. She is a Chief Economist and the co-founder of Lumen Energy Strategy.

MS. AYDIN: Thank you. Good morning. First slide, please. Next slide, please.

I'm here to talk about the new climate projections for California and to give you a tour of some of the trends and patterns were seeing in the data that are relevant to demand forecast.

So, I'll first start by giving you a brief overview of what I mean by new climate projections for California. And then, I'll take you through a few summaries of the data, including high level temperature trends in California and what that looks like when we zoom down to the weather station level. What temperature increases might look like in terms of number of hot days 30 years from now versus today. And then, what heat waves might look like in the future and how they might change in duration and severity.

Next slide, please. I think we skipped a slide. Thank you. This graphic on the left I'm sure looks very familiar to you. It's the key takeaway form the IPCC's latest outlook on what might happen to global temperature changes through the end of the century. And it's shown under different climate scenarios, or SSPs.

It's supported, these projections are supported by a whole suite of global climate models, or GCMs, and together these model projections are sometimes referred to as the CMIP6 projections.

If anyone on the line or in the room, if you're head is swimming and you think you've heard too many acronyms just now, you're right you have heard too many acronyms. I just wanted to get them out of the way.

So, the climate projects, they come with their own language and terms, which we're now all working to add to our energy vocabulary.

So, the important terms are the ones -- for this presentation are the ones I just mentioned. They're also shown on the right.

And I'll just add to that, there is some terminology around how we talk about the historical period. So, the historical period, you can think of it as something that you've observed, so historical observed. That, for example, would be a measurement taken at a weather station.

You can think of the historical period as something that you can reconstruct. So, if you're trying to figure out temperatures between two observations, two weather stations that's something that you can model.

Or, you can think of the historical period as something that you can model. And when you model the historical period, you're not necessarily looking to recreate what actually happened.

You might be modeling to look at and explore the possibilities of what could have happened in a prior year. And that's what the GCMs are doing. So, the GCMs are modeling both the historical period and the future period.

And these IPCC projections, they're very rich in information, but they're at the global scale. The CEC has been working with the climate science community to take these projections and bring them to a finer level of detail, so we better understand what's going on in California.

So, the slide in the middle, that's from a recent CEC presentation and it just demonstrates how the raw GCM outputs are being downscaled to a finer spatial granularity to 45 kilometers, 9 kilometers, and even for some runs the 3-kilometer level.

And this is -- downscaling is a very difficult thing to do. That, in itself, comes with a whole suite of models. But the good news is we're starting to see the results of that effort and that's all feeding into a variety of planning, adaptation and mitigation efforts in the state.

Next slide, please. And before I go further, I want to offer a few clarifications on how we're approaching and interpreting these data.

The number one thing we have to keep in mind is that no one can predict the future, and we're all well aware of that I'm sure.

The climate projects, they're rich, they're detailed, they have a lot of information about the knowable possibilities of the future, but like any data they do have limitations. And really, nothing is going to get around the fact that the future is uncertain and that we have to make some judgment calls when we're using the data for planning and for risk management.

But you'll see us walk the line sometimes of trying to get the most information we can out of the data, but also keeping in mind those limitations and uncertainties so that we don't fall into the trap of taking the projections too literally, and from that creating false precision in our planning.

You'll also notice in my slides that I focus a lot on high temperatures. There is a lot more than that in the projections. We are looking at hourly temperatures across different years, different GCMs, different climate scenarios. And then, there are other really useful metrics in the projections as well.

And for the stakeholders here, on the line, in the room, if you're interested in learning more about climate projections and exploring the data, I highly recommend getting familiar with the Cal-Adapt tools. The CMIP6 downscale projections, they're sort of hot off the press, so they're still in the process of getting integrated into all these tools. But they do have a lot of great data resources and visualizations, so please check that out.

Next slide, please. And now with that said, I'll start you off with a look at the long-term climate trends for California. And you may have seen different versions of this in the past.

But this chart shows for each year, 1980 through 2100, an average of summer daily max temperatures. And to get -- you'll remember that the downscaled data are very spatially granular. So, to get this bird's eye view for the state, instead of taking a simple average across every part of the state, what we did was we looked at temperatures for every weather station used in demand forecast. And then, we took a weighted average of that using the station weightings, also used in demand forecast. And that's for the CAISO footprint, I should clarify.

So, you can think of this more of a demand weighted average of temperatures for the CAISO footprint.

And also, we're showing five data series here. One is historical observed. And then the other four are four GCMs from the 7.0 scenario. And remember, the GCMs are modeling both the historical and future period.

And so, what we see here for California specifically is, number one, there's a clear upward trend, which should be of no surprise.

And then, we also observed that for any particular year there's a range of possible outcomes for that year.

And these two takeaways, they present some very difficult planning challenges. As the trend might be telling us we can generally expect max temperatures to go up. But if we're trying to figure out what a mild versus extreme year looks like in 2030, or 2050, clearly we see a departure from historical patterns. But we can't just take the climate projections literally for that one year and say, yeah, that's all that could possibly happen in that year.

To do that, when you only have one run from each

GCM, you would have to be pretty confident that the GCMs are getting the exact timing of weather cycles right, which is not the best use of these projections.

So, it does take some interpretation and translation of those projections to figure out, well, okay, what is the range of possibilities, possible weather outcomes for any one particular demand forecast year.

And Onur, in his presentation, he'll talk more about that and how we try to figure that out.

Next slide, please. So, the climate projections, they are spatially granular. You don't really see that in what I just showed you, in the CAISO-wide summary.

So, here we're showing temperatures through end of century at six different weather stations across the state. And instead of showing the historical observed plus four GCMs, we're just showing one GCM. So, that's modeling both historical and future period.

And then, for each year we're showing three temperatures. We're showing the coldest one percent of temperatures as the bottom line, the hottest o ne percent of temperatures as the top line, and average temperatures as the middle line. So, you can see how those are different and how they trend differently as well.

Different weather stations, they have different ranges of temperatures that they experience. So, the more coastal weather stations on the left, they have a narrower band of temperatures versus the inland, more inland weather stations on the right with a wider band.

And the high-low temperature, the high versus low temperatures, they can trend very differently. If you look at the bottom right, for the Gillespie or Santee weather station for example, the average temperature is trending by about 9 degrees Fahrenheit over this very long period. And then, the hottest temperatures are trending up by 7.5 degrees. But the coldest temperatures are trending up the most, it's 12.6 degrees.

So, I'll just note, again this is for only one GCM, one climate scenario. This is really just an illustration of what you can get out of the data. You'll see different numbers if you look at different GCMs. But the general takeaway is that the climate projections, they don't show a uniform impact across locations or across different times of the year, if you think of the different temperature levels as happening at different times of the year.

And this is important because these asymmetries in temperature changes amongst demand centers, that's the information we need to better understand when and where demand in the energy system in general might be the most stressed in the future. So, we really need to understand that and capture that in our analysis.

Next slide, please.

MR. WENDER: Can I ask, quickly, on this one?

MS. AYDIN: Yeah.

MR. WENDER: Do you have a sense of how much the temperature range has changed based on the different GCM inputs that's used? Is it like multiple degrees across the different GCMs?

And then, I guess building on that, what are the biggest contributors to variability or uncertainty in these forecasts? How much comes from the GCM and the inputs coming from the modeling side versus maybe uncertainties in the downscaling methodology, and the local climatic variables?

MS. AYDIN: Those are really great questions. I would say there are -- there is a band of -- so, for your first question. They can -- the different GCMs can differ within a climate scenario. But the biggest difference is if you look across climate scenarios.

If we go back a couple of slides to the IPCC chart, we can kind of see it there. So, there are bands around the different climate scenarios.

What I've been showing you is 7.0, which is the second to top one. But you could take a more extreme climate scenario or a more mild climate scenario, and so that's where you get the biggest difference.

The IPCC 6 report is much better than its predecessor at exploring uncertainty and describing it, and explaining it in the projections. They call this deep uncertainty, looking across climate scenarios. And so, that's really going to be the biggest driver of the differences you see. And it can be very difficult to just pick which climate scenario you want to focus on.

I'm not sure, did I answer your question?

MR. WENDER: Yeah, very helpful.

MS. AYDIN: Okay. Okay, thank you.

MR. WENDER: Then I guess this is the last one, and I don't know how much this is answerable or we can take this offline. But the amount of variability based on different downscaling methods, if you explored different approaches to the downscaling and how much that compares to maybe the scenario uncertainty going in?

MS. AYDIN: I may not be the best person to answer that, just because I haven't done the downscaling. So, the Scripps Institution of

Oceanography, along with UCLA and UC Berkeley, they have been doing that work, and those are their models.

So, I apologize, I don't think that I can answer that question.

MR. WENDER: Totally fine, thanks.

MS. AYDIN: Thank you.

Okay, next slide, please. So, we then wanted to look at the temperature increases through the lens of the number of hot days people might experience now, versus 30 years from now.

So, what we did is we looked at those four GCMs that I mentioned, under the 7.0 SSP, and we constructed 120 weather variants for each year, 2023 and 2050. So, 120 variants for 2023 and 120 for 2050.

Onur will explain more about how we get those variants.

But across those variants we counted the number of days reaching at least 90 degrees Fahrenheit. And so, we looked at those results for all the variants and then found the average number of hot days you can expect in 2023 versus 2050. And then, we took the difference of that to see the change, and those are the numbers you see here in the bubbles.

Again, we see a lot of variation depending on location. Some stations don't see much of a change and others see many additional hot days. So, I think it's San Diego Weather Station for example, under this GCM and climate scenario and with our weather variant methodology, you see only one additional hot day at 90 degrees plus by 2050.

But if you look at Fresno, it's 17 additional hot days 90 degrees plus.

In some locations the additional hot days are 90 to 100 degrees. Those are shown in orange. And in other places the additional hot days are between 100, 110 degrees, or even more than 110 degree days.

So, Blythe for example, in the lower right corner, they have -- we're estimating additional 13 hot days by 2050, but 12 of those are above 110 degrees.

Next slide, please. And when we expand this view, we look at -- and look at more weather stations, and we look at both what would happen in that expected year, 2023 versus 2050, and more of an extreme year for each of those planning years. We also see increases in the number of 90 degree plus days.

So here what we're showing in the bars, instead of showing the 30-year change, we're showing the total number of 90 plus degree days. The first bar is for 2023 and the second bar is for 2050.

So, if you look all the way to the left for those first two bars for Fresno, for example, the first bar says that in 2023 you can expect about 110 hot days, but by 2050 it's closer to 130.

And the bars on the left charts, they show an average or a 1-in-2 outcome for each year, and then on the right a more extreme outcome. So, you can see how across the board we see the number of hot days increase.

And we also see by looking at the absolute numbers that some locations, they already have a higher number of hot days to begin with. And so, the strain on both demand and supply in those locations, that's going to be quite high.

Next slide, please. And finally, here's a look at heat waves in the new projections. This is a heat plot of daily max temperatures 100 degrees Fahrenheit or above.

I'll just stress that this is just a peak into the climate projections. This is just showing one GCM run under the SSP3-7.0 scenario, and now we're down to just one weather station. That's for Sacramento.

So, looking at the top graphic, going left to right you see, again, the years 1980 through 2100. And going top to bottom are the months going from February to November. And each cell is a day.

The bright purple cells show days that are 100 to 110 degrees Fahrenheit. And then, dark purple shows the days that are 110 plus degrees. So, you can see this trend of the number of hot days increasing.

The bottom stacked chart shows the same data, but for each year it's showing the maximum number of consecutive hot days at 100 degrees or more. And that includes the longest stretch of 100 degrees as the dark purple area.

So, we can see here that there's this pattern of heat waves getting longer and more severe.

And I hope that was useful to you. And I'll turn it over to Onur unless you have any questions.

MR. WENDER: I just -- to clarify, the bottom plot is the same Sacramento Airport Weather Station?

MS. AYDIN: Correct.

MR. WENDER: Okay.

MS. AYDIN: That's correct.

MR. AYDIN: Hi, this is Onur, with Lumen Energy Strategy. And, you know, very excited to be part of today's discussions.

So, I would like to start with an overview of what we're aiming to achieve and the underlying motivations.

So, if you go to the next slide, please. The beta data is an essential part of energy demand forecasting.  Yes, there's a very strong relationship between the temperatures and the demand levels that are driven by cooling and heating related energies.

And our goal is to develop a set of all these weather variants that reflect the range of potential weather outcomes that can happen in a given future year, in a way that can be used in demand forecast.

And if you look at the recent heat waves in California that happened, these events highlighted the importance of extreme weather events and how they're characterized in grid planning studies, where demand forecast is a key input.

So, using long historical datasets as it has been, it can increase the range for outcomes that are considered, but the weather data from 20 or 30 years ago are now less and less representative of what can happen today or in the future.

So, this is something that's already recognized in the previous IEPR cycles, you know, by both the CEC staff and the stakeholders.  And the interim solutions that are considered were like shortening the historical window, focusing on most recent historical observations, or applying heavier weights to most recent years, but keeping the full, broad historical dataset, a long history.

So, these solutions, while they directionally improve the forecast, there are some inherent limitations which I'll discuss next.

So, if you could go to the next slide, please. Extreme events. So, because the extreme events and the extreme weather is becoming increasingly important to grid planning, you need to consider a broad range of possible weather years and improve how we represent the -tail events you know, like they happen every 10 years or 20 years, but still really important for grid planning.

So, the charts here show the distribution of daily maximum temperatures at CAISO based on a demand-weighted composite temperature statistic during the summer months over the past 30 years.

And the previous IEPR cycle for the normal uses a 30-year window, which is why this one is on that period.

So, on the left what you see is the ranges of temperature outcomes in each year. The gray box, which shows the middle, 90 percent of summer days, the 90th percentile. And the top of the red bar shows the hottest summer day of the year. And the bottom of the blue bar shows the coldest summer day of that year.

So, if you look at this chart very closely, I mean this highlights that extreme temperatures tend to be much, much more variable and volatile, you know, right, compared from year to year, compared to less extreme temperature levels.

So, for example, looking at last year's summer, the hottest temperature was nearly 10 degrees higher than the year before. But the difference in average summer temperatures was 102 degrees, so you can see that as the dark gray circle on the chart.

And on the right you see the distribution of the hottest summer temperatures over the same 30-year period. And you can see that most of the historical data is clustered around 100 degrees. Well, we've had some extreme years with the temperatures that are scattered 5 or 10 -- 5 to 10 degrees above that level.

And many of these extremes were seen in recent years, in 2017, 2020, and most recently last year in September 2022 we've had heat waves, and all of that shows up on the tail end of this distribution.

And looking at the historical record alone, it's not possible to tell if such events will be rare events, as has been historically, or if they'll be come -- they'll be observed more frequently going forward.

So, this all points to a need for bringing in projections, the climate projections.

But before I talk about that, I want to emphasize the importance of historical data. It’s powerful. I really think it’s powerful. It’s a really good anchor point. It’s based on events that actually happened and observed, which makes it almost indisputable, except for measurement errors that needs to be address. But at the end of the day it represents just one realization of possible outcomes, no matter how long of a history you look at. And with changing climate, using historical data alone is not sufficient to fully distinguish trends from variability, and then multi-year cycles. All of that is blending and it’s really difficult.

And historical data certainly won’t capture the emerging novel weather pattern that can be expected as climate changes.

Next slide, please. So, where does this lead us? So, we urgently need to integrate the latest high resolution climate projections into the demand forecasting process that the projections that Mariko described.

We’ve been cooperating with the CEC staff and called up the teams to identify how to best do that within the existing framework for this cycle, and also in the future cycles.

And one of the challenges is that when we look at climate projections over time we see a very high use year variation due to just natural or certainty of weather patterns. And, you know, of course this is something that we also see historically. And Mariko mentioned that, too. So, you know, for demand forecast, okay, given future year, say 2030, you cannot simply plug in the climate projections for that year. There will be a large uncertainty band around what could happen in that year.

So, we think it would be more prudent to draw from a number of years before the forecast year and a number of years after, as those years would reflect different potential weather outcomes associated with year-to-year variations.

We would also look at multiple climate models to improve characterizations of a model uncertainty. And just looking over a 30-year window is something that’s commonly used by climate scientists when exploring projected changes of climate.

When we draw from these projections, we cannot say a 30-year window. For the purpose of demand forecasting, it would be important to ensure that the data reflects the expectations of the forecast. And this can be achieved by de-trending the data.

So here, the simple graphics illustrate the concept. So, in the example on the left you see the raw temperature data that's trending by about 2 degrees over a 30-year period, from 96 degrees Fahrenheit to 98. And, you know, plus-minus 15 years around the forecast year, which is shown in the middle.

And what the trending does is it centers the temperature level, the distribution at 97 degrees as the level expected for the forecast year based on the climate simulations.

And then, this raises the temperatures for the weather variance prior to the forecast year and then lowers them after the forecast year. So, they are now more applicable to the forecast as variants for the forecast year.

Next slide, please. So, in her presentation Mariko highlighted that projected temperature trends are not uniform by showing how they varied by location and by temperature level. And so, it's important that this is accounted for when we de-trend the temperature data to create weather variance.

And this slide includes an example of how you would do that. So, if you look at the graph on the left it shows the annual temperature statistics like, you know, a maximum, top and bottom, 5 percent on the median temperature levels throughout the year. For one climate simulation, as selected, weather station at Riverside. And the data shows the years 1980 through the end of 21st century.

And on this chart the dashed line shows the trend line over that period.

And we put a box here that would be used for developing the ensemble of weather variance for the bas year, which is 2023.

And the graph on the right shows the data after they trend it. And after each temperature level they trend it around the expectations of 2023 and the corresponding frequency distribution of minimum, maximum, median temperature levels.

So, this last chart uses the -- so, the first two charts on the left, in the middle, shows an example of one climate simulation. But the one on the right draws from four climate simulations that are downscaled at the hourly level that we're using.

So, the actual calculations would use more granular temperature than shown here. But at the end, the approach, you know, our approach based hourly, it maintains the hourly chronological, which is really important to preserve correlations over time, correlations across different weather events, correlations between temperatures and other weather variables that are simulated into those climate projections. So, keeping track of the hourly chronological order is really important as inputs for demand forecasting, hourly demand forecasting used.

And here, using a rolling window, even though mechanically you can use the entire dataset, using a rolling window of like 30 to 50 years, important because it helps avoid carrying weather patterns from just the future or past relative to the forecast year that may not be applicable in terms of the shape of the weather patterns for that forecast year.

I just want to move to the next slide, please. Okay, so this slide shows very similar graphics to demonstrate how we would implement the trending for future years. So, the previous slide showed the de-trending for base year, how that would work, and here we just show how that can be implemented for forecast of future year, using 2050 as an example.

So here, the established long-term trends would stay the same as before, you know, showing the dashed lines on the figure. But as the rolling window shuts with the forecast year, the expectation for each temperature level would move along that long-term trend line.

In this example, all temperature levels rise based on the upward trends in the projections, but the amount is different for each temperature level that’s there. So, the maximum temperatures would rise at a different pace than the minimum temperatures and so on.

And another thing that I want to highlight is, and the next slide would show a little more details on that, is that the variables around the expected temperature loads also changes as new future years are introduced and the past years relative to the forecast year are gradually dropped.

And in this final slide, the next slide, please. So, this final slide zooms into the results for that same example at Riverside station. The result from the previous slide then shows how the distribution of potential outcomes can be affected by both the trends and also changes of variability in projected temperatures.

So, this means that the effects on normal events, that can be expected ones every two years, could be very different from the effects on more extreme conditions. You know, an event that can be expected once every 10 to 20 years.

And the graph here shows an example of how the distribution of hottest and coldest temperatures of the year are projected to change from current levels to 2050, based on the four climate models that we analyzed so far.

But as Mariko said, the data is -- this is hot off the press. And as more data is becoming available, we plan to expand the climate models that are closer in the analysis.

But looking at the hottest temperatures on the left, you know, we see projected normal levels rising by about 2 degrees. Right, they are shown as circles.

But the upward tail of the distribution increases much more than that. And this is due to increased variability seen in the simulations.

And then, if you look at the other end of the spectrum, for the coldest temperatures, on the right we see, also as Mariko mentioned, that we also see projected normal levels rising according to the climate projections we processed.

But the bottom of the tail of the distribution declines. So, this suggests that the cold snaps can actually get potentially colder, even though on average, a typical year you might see cold becoming less cold.

But yeah, with that, you know, I just say that concludes my presentation. We can take any comments or questions.

VICE CHAIR GUNDA: Thank you so much for these presentations. I had a chance to view the decks a little bit. I have to say this is a little bit out of my depth trying to understand and catch up on internalizing some of this information.

So, I want to just bring this up to a little bit of a higher level and think about how the changes that are being made are going to help with some of the problems we have been seeing, you know, the last several years.

So, the problem statement from kind of my vantage point has been we are using -- we have two types of planning, right, so for the resources. Ultimately, the entire demand forecast is a foundational step in ensuring we have the right resources for a clean energy transition, and then being able to have a reliable system, and how are we capturing the temperature and weather impacts into that planning effort.

So, when we are doing that resource planning, we have slowly emerged into this dichotomy of there is a planning standard, right, in resource planning, which is I'm going to take all the weather, develop a demand distribution. And then, the demand distribution is matched with a supply distribution and I'm going to plan for some sort of a standard. Which is I'm not going to have more than one outage every ten years once I match all of them together.

And the second element is we're saying incremental to the planning standard, we may see some tail events that is not going to be captured within the standard planning and we need to have some emergency resources ready to support reliability.

So, kind of setting that framework my question on this one is, you know, how are we -- do we feel like we have a good sense of the distribution of temperature, which then drives the demand, to be able to capture a resource planning better. Right, so that's the first question.

The second kind of tangential question to that, if we are going to move away from the appropriate way of doing things which is, you know, stochastic analysis on the distribution level, and trying to do point estimates, you know, for resource planning, which is kind of a proxy we do in RA and other planning, does the work that we're doing right now -- how does that support, right, the de-trending, you know, Onur, that you mentioned, you know, how does that help give us the cushion in this temperature variability as we move forward.

So, I just want to set the stage there. I will try to internalize, maybe have meetings with you all to further understand the very, really gritty details, and we can continue to talk through.

MR. AYDIN: Yeah, that's really -- you know, both questions really are good questions. So, I think Nick was also, in the next presentation, was planning to touch on that.

But in terms of -- the current historical approach, so a big step towards -- currently towards seeing the -- for the planning distribution of extreme events. Extreme in the sense that, you know, events that you can expect one every 10 years or 20 years, is captured as a part of demand normalization process which currently uses the historical data.

But as we move towards using climate projections and develop those climate -- you know, they call it climate -- demand variance, and the weather variance, and get a rich distribution of potential outcomes, we expect that both the normal levels that the reliability planning is set for, and also like more extreme events will likely, likely go up. And using the climate projections would give a better resolution of outcomes.

Even when you look at just kind of point estimates at, you know, like there's the selected stations that are used currently for developing system-level level estimates.

But I think the next phase would be to really bring a more detailed, geographically finer resolution of the data that are like -- you know, a lot of those climate projections that we are using as inputs are developed by, you know, tacheometer by tacheometer. And for the purpose of this cycle that is being just translated to station levels because that is the current approach, and for the sake of integrating with the current approach, you know, just making the step improvements. So, that's what we've been focusing on.

But the approach that we described is scalable. So, you know, that the trending can also apply to the granular tacheometer by tacheometer data.

What that would really require is at that fine granularity to have a better understanding of the temperature response, like of the demand at that locational level.

It's something that's not done, yet, but used with the more detailed data, the AMI data that's becoming available, that's something that can be done in future IEPR cycles and improve the resolution of the demand forecast, and align it with the resolution of the climate projections.

But I'll pause to see if Mariko has any

additions.

MS. AYDIN: Yeah, I can respond to a little bit of that. First of all, it’s a very insightful question. I’m not sure if I have all the answers. But when I think about the planning standard and loss of load expectation that is more of like a stochastic view. But it gets translated into a planning reserve margin, and that’s what we planned for.

I think what we’re seeing in the planning standard, just in the current context, is that there are some blind spots there. So, I’m not sure if the full future weather and climate variability is really getting embedded into that loss of load expectation and then carrying through to a planning reserve -- a planning reserve margin.

So, that’s a question and we’re just trying to address those gaps and see, given the planning reserve margin that’s in place, are there additional situations or possibilities that we need to consider and maybe add onto that.

The other kind of direction that we’re trying to go, and the reason that we show heat waves and extremes is with so many -- well, with so many and growing energy-limited resources on the grid, one thing that’s becoming more and more important is getting that time profile of when the grid is really stressed. And so, that's going to take a lot of work to really bring into demand forecast and restructure the architecture of it to be able to capture that. And that's sort of like one thing we're keeping in mind as an end goal is can we represent like a cohesive weather year, or meteorological year, and plan for that and explore what is sort of a normal year. I mean every year in California has some kind of heat wave, right. So, are we reflecting that in our normal year. Are we exploring what's an extreme year in those terms.

And just being able to get to that level of granularity, which these climate projections help us do, is an opportunity for us to reduce those blind spots.

VICE CHAIR GUNDA: Yeah, thank you so much. Go ahead, please.

MR. AYDIN: Oh, sorry, I just wanted to maybe bring up like slide 3, just to kind of illustrate that, you know, Mariko's comment about the blind spots.

VICE CHAIR GUNDA: As we're bringing that on, I think, you know, Mariko to your point, I think there has been this concern, right, in planning because we're not doing a good job capturing the weather. But I think to your point, part of it is trying to incorporate the weather projections and climate projections into the demand forecast. But just because we do that doesn't mean that the rest of the processes are in place.

So, I think it's really helpful to think through that holistic band because I feel like part of CEC's responsibility is to be that forum for that discussion. So, to the extent that we think through climate projections, all the way to keeping the lights on, under both standard, or in a normal weather year, however we want to describe that, and an extreme weather event what are the different places that these climate projections have to be incorporated and reflected, right.

For example, if we do, to your point stochastics, it absolutely has to be captured there, but then it has to be captured in the PRM to be able to kind of then, you know, adequately resource.

So, it would be really helpful to, within the forecasting context this year, at least having this light, right, kind of showing how we're doing these elements of different spaces, but it needs to be more broadly incorporated for us to get the benefits of those climate projections in keeping the lights on.

MS. AYDIN: Yes, if I may respond to that. This is the curse of being a forecaster. And I'm very sorry to hear that perspective because I think that California's state demand forecast is probably the most sophisticated in the country. It's very detailed, very thoughtful.

And I think, you know, no one can predict the future. I'll just go back to that, nobody can predict the future. The best we can do is use all the information that we have in front of us and make the best decision that we can make.

And I think these downscaled climate projections are so great because they do give us more information that we can incorporate and help us reduce those planning blind spots. And, hopefully, maybe not get that one point estimate of peak demand exactly right, because no one can do that, but really be able to explore the ranges of what's possible, and have this discussion to figure out what to do next in planning.

VICE CHAIR GUNDA: Yeah, just I want to close that off. From my perspective, I think to Nick and, you know, Heidi, I think as a part of our IEPR forecast this year having visibility on -- you know, piecemeal doing a better job in climate projections doesn't, you know, just result in a better portfolio downstream.

And being able to kind of just articulate all the different place qualitatively that we need to be able to do this to better plan for both extreme and resource planning would be really helpful.

And I think given that we have a very, you know, narrow mandatory statute affects developing the demand forecast doesn't just end with that. But, you know, at least suggestions and recommendations on how the weather, the climate projections, and our demand forecast should be incorporated into the broader setup. So, thank you so much. That would be helpful.

MR. WENDER: I want to say this is amazing. Not that there aren't many other places along the entire planning decision making change where similar advances need to be thought through, and that dialogue needs to be fostered, but I think this is an incredible step towards taking even more sophisticated approaches to understanding our rapidly changing climate, and what that means in terms of planning our energy system, producing the resources that we need to maintain reliability throughout this climate change.

So, you know, first and foremost tremendous progress. Kudos to the whole team for folding these advances into our thinking here.

Wild to see not just warming average temperatures, but warming low temperatures, growing extremes. I think that emphasis and really focusing on those extremes is critical and great to see that here because that drives so much of the grid and the ultimate impacts to our communities here in the state, who deal with these, you know, 10, 20 consecutive days above certain temperature bands.

I was going to ask, we focused a lot on temperature today, but curious if you have thoughts or other insights into other, you know, variables, parameters that you think we have some of the modeling capabilities to think about. So, precipitation is a big one and understanding, starting to again kind of explore what these changing climate trends might mean for precipitation, and hydro resources.

And then, the other one is kind of thinking both this very hyper localized forecast, tremendously valuable, but also thinking about trends on wider scale impacts. So, as heat events cover larger and larger areas of the Western U.S., or the entire U.S., thinking about what that might mean in terms of import availability and tightness of imports, and how we can think through those other dimensions of a changing climate in terms of our forecasting, and then eventual later steps in the planning and procurement processes.

MR. AYDIN: Yeah, I mean we are quite definitely looking -- so, yeah, I mean today our focus has been on temperatures as the most impactful metric. But we definitely are like, just coincidentally looking at other weather variables, including like the humidity on temperatures is one thing that we want to really better understand, too. Because the temperature alone may not explain the demand behavior as well as, you know, just looking at the effects of humidity.

And there are other researchers works that we're coordinating with, who are looking at these kind of projections in the lens of impacts on supply availability. Including effects on the hydro availability with the prolonged droughts, and how that would -- you know, just kind of link it to the climate projects. As well as the availability of wind and solar resources. Because, you know, you can think of a situation where, you know, the demand in general the load centers are seeing, you know, extreme heat events. But, you know, coincidentally like, you know, the solar resources are at areas with some kind of cloud cover, and the simultaneous increase of demand, compounded with reduced, you know, renewable resources would really create some challenges that may not have been seen before. And that's definitely something that we are thinking.

And as the data becomes available, you know, not just in a California focus, but also for the entire Western Interconnect, there's some climate projections.

It's something that we want to really, really consider in terms of, like what you said, about the availability of imports. Because if multiple areas see the same kind of constraint at the same time, that's a very different type of event than just California's seeing by having that cushion from the import available.

So, those are definitely really the points, that's something that's in our radar. As we have more information available in the future workshops, hopefully we'll have more to share.

VICE CHAIR GUNDA: Thank you. I think we can move to the next one, but I will definitely follow up with both of you on further understanding the details of this, the implications of this.

Unfortunately, I have to step out for the rest of the morning session. I'll hand it over to Ben for the rest of the proceedings. I know I just -- for those of you who do not see Nick and his gestures here, he seems incredibly frustrated. No, Nick, I apologize. I will follow up with you on the HLM. And maybe we can repeat, do a repeat in the afternoon, a quick repeat. Yes.

MR. FUGATE: Sure, no problem.

VICE CHAIR GUNDA: And ask all the questions I missed to listen and the details on it. Thank you.

Thank you so much for the understanding.

MS. JAVANBAKHT: All right, and with that I will hand it over to Nick Fugate, our Chief Forecaster, for the last presentation this morning.

MR. FUGATE: So, I was going to start off by saying good morning, Commissioners, but I'll instead say goodbye to the Vice Chair.

(Laughter)

MR. FUGATE: So, I'm Nick Fugate with the Energy Commission's Demand Forecast Unit. And I'm here today to discuss our hourly modeling process and some of the updates we have planned for this cycle.

I will say, preemptively, that the focus of my presentation is going to be mostly on our existing process and sort of the impacts that this climate, and some new data we have on self-generation as well, are going to impact the forecast in the near term. But certainly appreciate all of the discussion around how our forecast can support stochastic analysis. That is certainly on our mind and I will touch a little bit on that in the presentation as well.

Next slide, please. So, for context, our hourly load model is a top down system model that considers how the electricity system load profile may evolve over the forecast period as we add more behind-the-meter PV, electric vehicles, heat pumps, battery storage, those things that can impact the timing of system peaks, the timing and magnitude of the system ramping periods, and just the overall -- the shape of the system, hourly system loads.

And so, our forecast is an important input into system and reliability studies. For the IOU TAC areas within CAISO, specifically we take our annual peak forecast from the hourly model. This is used in the CPUC’s IRP process and CAISO transmission studies.

Similarly, we take our monthly peak forecast from the hourly model results and these are used as benchmarks for system RA. And the hourly loads are used directly to inform Flex RA studies, which assess resources needed to meet maximum 3-hour system ramps.

This is probably the highest level overview I could give of this process. Really, I just wanted to remind everyone that these three pieces of our forecast, which I’ll be talking about today, what they are and how they’re related.

So, every year we perform a peak normalization analysis, where we look at the relationship between load and temperature, and we estimate what peak load would be under normal conditions.

Our hourly demand forecast is intended to represent load in a particular hour under normal conditions for that hour. And we want that normal peak estimate to be the starting point for our forecast. And so, we use it to calibrate our hourly system load profile in the base year. And as I mentioned on the last slide, we then take the annual peaks from the hourly model results and those become our one and two -- one- and two-year peak forecast.

There are a number of electricity system studies, however, that look at energy or transmission needs under more extreme conditions, say a one-year-in-five or a one-year-in-ten event. What we have traditionally done to support those studies is apply a scale factor to our 1-in-2 peak forecast. That scale factor falls out of the normalization process. In that top box I say we estimate what peak load would be under normal conditions, but we also develop similar estimates for, say, a one-year-in-five or a one-year-in-ten conditions and we compare those to normal conditions.

Next slide. So, I want to talk a little bit about that normalization process and some of the updates we have in mind for this cycle.

Next slide. The way that we approach this has traditionally relied solely on historic load and weather data. The chart here illustrates that in the higher upper temperature ranges there’s a pretty linear relationship between daily peak load and temperature.

We take daily peak loads and weather data for the three most recent summers and use that to estimate a linear model. We then use that model to simulate many different summers, using different weather patterns. And then, we examine the peak loads from those simulations and look at the distribution to determine what a one-year-in-two, or a 1-in-5, or really a 1-in-X peak load event would be.

Next slide. So, the weather patterns that we have used for this simulation have been, in past cycles, taken from the historical record exclusively, specifically the last 30 years of weather data, which is generally considered long enough of a window to capture warming and cooling cycles that take place over decades.

In the context of a warming climate, though, and we touched on this in Lumen’s presentation, this 30-year window presents some problems. Intuitively, hopefully it makes sense that as you’re taking periodic snapshots over time of a system that is evolving and becoming characteristically different, the you wouldn’t want to look too closely at those early to see what the system looks like today. You’d want to look at more recent ones.

And so, that’s what we had in mind as we modified this process two cycles ago. The chart here illustrates with a couple of density plots the distribution of maximum weighted temperatures for one of our planning areas. I could have picked any of them, the plot would be similar.

And you can see the distribution across the last 20 years has a higher median and heavier tail than if you look at the last 30 years.

We only had the historical record to work with. Truncating the window doesn’t completely address the problem. It also poses some additional issues. We need to have enough variability in the record to establish with confidence what a 1-in-20 event is. And if you only have 20 weather patterns to consider, then one or two of those patterns can easily skew your expectations.

All of that is to say that we are really excited about the data and tools that Mariko and Onur discussed in their presentations.

The Cal-Adapt analytics engine, the downscale climate model runs and the, you know, they’re relevant to this weather normalization analysis. The prospect of having a rich, de-trended set of hourly temperature simulations to support our historical record, you know, is very promising as a pathway to improve this process.

MR. WENDER: Nick, can I ask one question?

MR. FUGATE: Yes.

MR. WENDER: So, you certainly see the progressing trend in peak -- high temperatures and peak demand associated with those. In the hourly breakdown do you also see increasing demand at off peak times or increasing kind of like base demand associated with higher low temperatures. I guess both the highs and the lows are increasing. And I guess I'm wondering the extent to which the steady increasing low temperatures are. Sorry, this is a mouthful.

MR. FUGATE: Yeah. Yeah, so --

MR. WENDER: I'll make it fast, in the hourly forecast.

MR. FUGATE: Yes. So, it sort of depends which hours or time of year you're looking at, right. Minimum temperatures actually do factor into our summer peak analysis. That is one of the explanatory variables, the most recent minimum daily temperature. And it does have an impact on the load response. So, yes, increasing, just specific to this, you know, peak normalization process, increasing minimum temperatures would have implications for that.

But also, if you're looking at just the -- at our hourly process in general or our methods for estimating climate impacts, we do sort of estimate, you know, load response to things like heating and cooling degree days. So, you know, as minimum temperatures increase that is going to have an impact on those metrics, the heating degree days in particular.

And so, you could see a load response sort of on the year as a whole where, you know, you have less heating demand in the winter. And so, that's sort of working in the other direction.

But, yeah, certainly minimum temperatures have an impact on load.

So, finishing up on this slide. As Onur described earlier, our intention this cycle is to introduce this climate simulation data into our normalization process. We can look at, for example, a 30-year window centered around the base year, so 15 years in either direction. And examine what peak loads would be under those conditions.

And because we have downscaled results from four different global climate models, that same 30-year window would actually provide, you know, 120 weather patterns. So, enough variation to examine extreme conditions.

And actually, this process can be repeated with de-trended data centered around future years, as well, which could provide insight into how 1-in-X peak factors might evolve over the forecast period.

We're currently working with Lumen's and test this approach, but this is a promising solution to this particular problem that we've been struggling with for a few cycles now.

Next slide, please. So, moving on to the actual hourly modeling.

Next slide. To develop our hourly forecast we have to apply load shapes to our annual energy forecasts. Just broadly speaking that is the approach. When we employ our hourly load model, which is what we have used for several cycles now, we start with a baseline profile for total end-user consumption, which represents what we think consumption patterns look like today.

We then take our annual consumption forecast, we back out all of the incremental components that would modify the shape of that baseline profile, things like electric vehicles, heat pumps, building electrification measures. We apply our baseline consumption profile to this modified annual consumption forecast to get a baseline hourly consumption forecast.

And then, we have to add back in all of those modifiers, those load modifiers. Each one has its own characteristic load profile. And that gives us a modified hourly consumption profile.

And then, we add the impact of behind-the-meter generation, which also has its own characteristic profile, and that gives us our hourly system load projections.

And as I mentioned earlier, that system load is benchmarked to our weather normal peak estimate in the base year.

Next slide. Some more review here. I've presented on the hourly model or what we call the HLM, I've presented on it every year for the last several years, so I'm skipping a lot of the detail here. But you can look at those presentations, if you're interested. They're docketed and posted to the IEPR website.

The HLM is the tool that we use to develop that baseline consumption profile, the one I described on my last slide. It's a set of regression models, one for each hour of the day that predict load as a function of weather and calendar effects.

We use five years of historical data to estimate the models. We then use those models to simulate 87 models for each of over 20 weather patterns. We then rank order the loads in each profile, creating a collection of simulated load-duration curves.

And we look at the first rank in each of those load-duration curves. We select the median value. We do that again for the second rank, and the third, and so on. And at the end of that process we have a load-duration curve that you could consider approximately normal. And we assign those values to particular hours of the year.

Now, there are some parallels here with the weather normalization process, the weather patterns that we have traditionally used. These were historical patterns, so there is the same question around how well those early years represent expectations around current weather patterns.

And there is the issue of having only about 20 years of data. This may not be as big a problem when you consider how we've used HLM up to this point. So, right, we've only been selecting median values, 20 years may be about as good as 30 for selecting the median.

But as the scope of our hourly modeling evolves to support more stochastic assessments of system reliability, 20 simulations starts to suffer from the same problem where, you know, two years can have an outside influence on extremes, or maybe we're not even capturing, you know, sufficient data points to really think about those extremes.

So, there is, this is another area where we are excited to begin ingesting climate simulation data. The climate data covers all of the correlated weather variables that we would need for this model. Again, a 30-year window of simulated weather actually delivers 120 unique patterns. So, there's a clear path here for using this in our current process, but it's also exciting because it presents an opportunity to rethink our modeling framework more generally.

And, you know, I don't want to get too far ahead of the actual work we had planned because there's still a lot of open questions, and this is something we will want to start engaging, you know, with stakeholders and start discussing some of our ideas.

But, you now, instead of using all of the HLM load simulations to distill a single, normal consumption profile all of that detail and variability could be retained. And you'd have this rich data set of load profiles from which you could select what looks like a normal year, you know, or a 1-in-10 year. You know, you wouldn't just have to have point values, you'd have the entire profile. And so, you'd have a lot of flexibility even in how you would define the contingencies you'd want to examine.

You know, maybe you're interested in years with extremely long heat waves or, you know, a year that has an unusually hot October, things of that nature.

So, it's an ambitious undertaking and one we're working on in parallel to what we have planned for this IEPR forecast specifically, which is to pull this new climate data into our current process. But that's just a first step and, you know, this climate data opens a lot of doors.

Okay, so if you'll allow me just one more context slide. When I talked about estimating the HLM, I said it predicts consumption based on weather and calendar effects. But I have to put "consumption" in quotes because it's not actually consumption. We don't know what consumption is. We can't measure that.

We can measure system load and we can estimate self-generation, specifically behind-the-meter PV generation, and we can add those two together to get a counterfactual historical load series. So, that's what we're actually modeling.

When we originally started doing this, we estimate the historical PV component by applying an average generation profile, literally an average across days of the week and across years, taken from a relatively small metered system study.

This worked well enough when there wasn't a lot of PV on the system. But as we have added more capacity, the differences between actual generation and this average value start to become pretty apparent.

Next slide. So, to explore just how large the discrepancy was, we modeled PV production in SDG&E's territory, using NREL's system adviser tool for specifically historical days. And then, we compared that to the average profiles we've been -- we had been using.

On the NREL tool models, PV generation for specific system designs using actual historical solar radiation data, these plots show PV gen for every day in January, but across two different years, 2016 and 2019.

The red line is the average profile we had been using. It's the same in both plots.

The blue line is what we modeled for those specific days using the NREL tool.

And it's clear from this that the average profile under-predicts generation on clear days and significantly over-predicts generation on cloudy days.

So, there are two problems with using average profiles in our hourly forecast. One is that using these profiles to reconstitute hourly consumption, right, which we're using to estimate our model, would lead to several irregular consumption patterns, especially in the winter and the shoulder months where you tend to see more cloud cover.

The other issue with using the profiles as a modifier in the forecast years is that there will be months when you should typically expect to see some significant cloud cover on some days.

And so, the corresponding drop off in behind-the-meter solar could drive the timing and the magnitude of the peak in that month. So, these issues motivated us to pursue procurement of actual metered system data.

Next slide. And we have done just that. We have entered into an agreement with a vendor to supply 15-minute inverter readings twice a year. Once at the start of each year, which we'll use to reconstitute the previous year's consumption, and then once at the end of each summer in case it's necessary to examine PV performance contribution to the summer peak.

Another benefit of this procurement is that it covers all forecast zones. And so, we have data now to reconstitute hourly for all our planning areas, and so we can expand the HLM to cover non-CAISA balancing areas.

Relative to the forecast generation profiles, this is in a situation where we would want to just drop this new data into our existing process and develop new average profiles.

We're testing other options that would introduce more of realistic variability into the profile. That's still a bit of an open question. But any new profiles we develop will draw heavily from this inverter data.

Next slide.

MR. WENDER: Can I just ask quickly on that one?

MR. FUGATE: Sure.

MR. WENDER: I would love to see for any given location, kind of the graph of what the actual measured new dataset you've gotten compared to SAM, or the assumed model, just to get a sense of -- or, the average model you used to use to get a sense of how much they really vary across those three.

MR. FUGATE: Yes, I'm excited to look at those, too. This is similar to the climate data, you know, this is sort of hot off of the presses for us, I think is the term the owner used.

So, yeah, you know, it's coming kind of late in our process but this is, you know, important enough we really want to try to leverage it this year. And so, we are putting together those comparisons now, and are excited for future meetings we'll be able to show some of those comparisons.

So, the updates I've covered so far are sort of the ones that are out of the ordinary, but there are also more routine updates we'll be making to the hourly forecast. We'll be reestimating that base consumption profile that I described earlier.

And in doing that, we are paying particular attention to factors which appear to be contributing to the steep system ramps that have been present in our last two IEPR forecasts, and in particular that have been surfacing in the context of CAISO's Flex RA studies.

We will reestimate our climate impacts using new projections for heating degree and cooling degree days. I suppose this one isn't quite so routine since these projections will be derived from the new climate dataset.

We'll be reestimating PV impacts, not just with the set of revised profiles, but also with the new PV adoption forecast and the updated history of cumulative installed capacity, which Alex described earlier.

And, of course, we'll be incorporating updated additional achievable scenarios being developed by our Advanced Electrification Analysis Branch, so I imagine you'll hear more about that in the afternoon sessions.

Next slide, please. So, I wanted to wrap up with a few points on work we have in mind for future cycles.

Next slide. At our -- I put this one in here specifically for Vice Chair Gunda. At our Tuesday workshop in inputs and assumptions, Vice Chair Gunda noted the importance of ensuring that the CEC's forecast accurately reflect current and future potential for behind-the-meter storage to contribute toward strategic load management.

So, staff agree with that. This isn't a component of our forecast that has received a lot of attention in the last two cycles.

Here I'm showing our non-res storage charge and discharge pattern for a peak day. This was informed in part by an SGIP impact evaluation study. There seem to be clear indications that multiple strategies are at play here, discharging at night, discharging in the morning, I would presume from solar.

Our storage projects to date have focused on total installed capacity, but it will be important moving forward to improve our understanding of what the operational strategies are that are being used, what new strategies may emerge, and then also what portion of our capacity forecast should be bucketed into each of these different categories.

Next slide, please. We also want to look at opportunities to improve the performance of our hourly load model. I mentioned earlier, in another slide, that we would like to use this model to support more stochastic analysis. And with that in mind, we will be looking for opportunities again to improve the model, particularly at higher temperature ranges.

The model was developed, as I described, to produce a normal profile. And then, we calibrate that load profile to peak -- the results of our peak analysis.

We'd like to reach greater alignment between those, you know, peaks derived from the raw model output and the peak normalization analysis so that the calibration step is sort of a minimal impact on the resulting profile.

We'll be testing other explanatory variables that may have a greater correlation to end-use behavior, heat index for example. Which, you know, relative to temperature gives a better indication of how hot it actually feels to people.

We're looking at the level of temporal granularity in the model. And what I mean by this is it's a little in the weeds, but right now, although we estimate the model for each individual hour of the day

-- estimate a model for each individual hour of the day, we have a single model specification for broad clusters of hours.

So, at least for the most temperature sensitive hours, it might make sense to have individual specifications for each hour.

And we're also exploring adding a PV efficiency reduction factor to account for the drop off in system output that many systems see at high temperatures.

Next slide. So, we saw last cycle that the level of additional achievable fuel substitution considered in the local reliability scenario adding a substantial amount of load to winter months. So much so that the winter CAISO peak in 2035 reaches 50,000 megawatts, which is on par with a really hot summer peak right now.

One of the problems with adding so much incremental fuel substitution into the model is, you know, this model is estimated on recent historical loads and temperatures. So, you know, it does not exhibit a lot of temperature sensitivity in the winter months. So, if we're wanting to look at variation in hourly profiles in, say, 2035 or beyond, you know, we can still layer in these AAFS impacts but they will -- you know, the way it's structured right now, they will just sit there as a static profile.  So, we're currently thinking about ways to approach adding some temperature sensitivity there.

Next slide.  And so, I'll end with a thank you to everyone who called in online, and also everyone in the room.  Especially all of our utility forecaster colleagues who made the trip to be here in person.  It's great to see everyone.

I also want to give a big thanks to the strong support we've received on climate this cycle from our Research Division here at the CEC.

Also to our consultant, Mike Nostrangia (phonetic), Eagle Rock Analytics, and the whole Cal-Adapt analytics engine team.  And to Lumen, we've have had a lot of help this cycle, not just with this new data and tools, but also thinking through the best ways to incorporate climate data into different elements of our forecast.

So, there's going to be a lot of iteration on this over the next few cycles.  More to come.  But the support in kinds we've received so far this cycle has been really valuable and I'm quite grateful.  Thank you.

MR. WENDER:  Thanks so much, Nick.  And echo the thanks for everybody making it up today, as well as the collaborators with Lumen with the Research and

Development Division. Clearly a lot of folks behind this great work.

I guess my one general question is really around kind of the timeline and thinking about when some of these more stochastic approaches might become integrated into the forecast discussions that you're having with the other energy entities around later steps, and use of these forecasts, and what they need to see to embrace, and feel good, and use these stochastic approaches. And the willingness to take this exploratory approach and picking different example years of different climatic conditions to explore and then translating that to what that might mean in terms of planning process, investment decisions.

And so, maybe just a quick look ahead of those conversations and timelines that you're anticipating.

MR. FUGATE: Sure. So, in terms of timeline it is we're not expecting to have sort of a framework for the stochastic analysis built in time for the adoption of this forecast. But following the adoption of this forecast we are sort of going to be pivoting to that as kind of a next piece of priority work for us.

We have already been discussing, we've been in discussions with, as you said, the other energy agencies, had a handful of preliminary discussions with some utility forecasters and looking forward to more of those.

In terms of the discussions so far have sort of been around, well, what is everyone doing in this space, because everyone has a current approach to it. And so, it’s been a lot of comparing notes to this point.

The climate piece that we discussed, we heard from Lumen today, is relatively new. We have had some sort of focused discussions on that in particular with, you know, CAISO and CPUC through our JASC forum. Really focused on kind of what this climate data is, why we feel, you know, this is really sort of the best approach to accounting for climate in this style of developing a stochastic (inaudible) profiles in the long-term forecast period.

So, we’re sort of socializing this new kind of a data and thinking through the best approach to actually developing these stochastic datasets.

MR. WENDER: Actually much sooner than I anticipated. You guys are much further along than I realized.

MR. FUGATE: Well, so, yeah, I mean this is -- this is definitely a high priority work. I don’t want to set expectations too high because it is hugely ambitious. And so, I think that, you know, our forecast period just in general is so -- our forecast window, you know, an annual cycle is just a really short period of time to both, you know, think through changes, implement changes, produce a forecast and, you know, bringing in all the stakeholder input that's necessary to do that in a transparent way.

So, I think that it's going to be iterative. We're having discussions. We want to get to a kind of a minimum viable product in the near future and start getting people comfortable with that, and then we will iterate and make improvements each cycle.

MR. WENDER: Great. The other thought I had, and I'm sure you folks have thought through this more than I have at this time, but it makes a lot of sense to think about efficiency adjustments for PV generation as a function of temperature. There's thinking about other large end loads or -- I guess I'm thinking loads right now, particularly in the EV space that may have changes in terms of, you know, range or charging demands with temperature.

MR. FUGATE: I will be frank, I have not considered that, so I would sort of defer to others who, you know, are potentially thinking that, you know, EV load charging patterns might be correlated with temperature or, you know, who have been studying that.

Certainly welcome that input.

I think we are kind of focused on what feels to us to be the lowest hanging fruit, right, that clearly temperature sensitive loads, right, the efficiency and fuel substitution. Additional achievement efficiency and fuel substitution, there's clearly a large kind of temperature driven component to those profiles. So, that's kind of what we have first in mind.

But definitely would consider any additional insight others have to offer on PV loads.

MR. WENDER: Very good. I think we're close enough now we turn it over to public Q&A, from anybody in the room. Or, maybe I'll turn it over to Stephanie to help facilitate that.

MS. JAVANBAKHT: I'm facilitating this session.

MR. WENDER: Oh, thank you, Heidi. I'll turn it over to Heidi.

MS. JAVANBAKHT: And Ben, just going back to your EV question, I think that's something that Quentin has been thinking about, if you want to pose that question again this afternoon to him.

Hopefully, I'm not putting him on the spot.

Okay, so we're moving to Q&A. We are only going to take questions through the Q&A box. For those of you attending online, if you have a question, please type it into the Q&A box. If you have a question for our presenters from this morning that's relevant to their presentations.

And we will start with questions in the room. Are there any question in the room? If so, please come up to the podium. Okay, we have one question.

MR. LAMICHHANE: Thank you everyone. I'm Santosh Lamichhane from PG&E. I'm the forecaster at PG&E. I have a few questions related to the climate presentations from Lumen. Pretty easy questions, I think, mostly related to the Cal-Adapt data.

You showed a slide with a temperature change for an individual weather station on slide 6, the first presentation. Is there a reason why you chose CESM2 scenario over the other, like there were four, I think, in the Cal-Adapt?

And I was wondering if it has some significance in terms of that's the median outcome or something, like I know it's an average, but I would like some clarification, if we can, on that one.

Also, if there's any reference to the methodology used for downscaling from the global climate models, that would be helpful.

And also, when you saw the de-trending for the Riverside station on the second presentation, slide 5 and 6, is that using all four scenarios?

Other than that, all the research you've done is very helpful for us, for utilities to, you know, get insights into the climate and how it's going to affect. Thank you.

MS. JAVANBAKHT: Oh, and sorry, one more thing before you go. Can you please spell your name for the --

MR. LAMICHHANE: S-A N-T-O-S-H L-A-M-I-C-H-H-A-N-E.

MS. JAVANBAKHT: Thank you.

MR. LAMICHHANE: Thank you.

MS. JAVANBAKHT: Onur, go.

MR. AYDIN: Yeah, thanks for the question. So, Mariko, I think the first question was for your slide. Do you want me to take that or I'll let you.

MS. AYDIN: Yes, I'll start and then pass it on to you, Onur.

Thank you for that question. For your Cal-Adapt question, you referred to the slides on individual weather stations and asked why did we pick the CESM2 scenario. I'm glad you caught that.

So, what we've been focusing on so far are the four downscaled GCMs produced by the WARF models. And why did we pick CESM2, I'll ask Onur. It is just illustrative, but when we do our de-trending we'll look at all four. I'll pass it to Onur to answer the CESM2 question.

But in terms of the downscaling from the global climate models, I do need to punt that over to the research teams who are doing that, just because I want to make sure that you get the most correct answer on that.

So, what I can do is offline point you to some of the -- they're the CDAWG meetings, which I'm sure you're well aware of, and other materials that will explain that much better than I could ever explain it.

And then I'll pass the rest to Onur. Thank you for the questions, though.

MR. AYDIN: Yeah, I want to second Mariko, like really good questions. So, I mean just in terms of the CESM2 scenario that was just for illustration I think we have it.

So, we want to work with the full set of hourly downscaled simulations, and so far we only have four of them. That's why we've been focusing on the four. In terms of picking that one it was, you know, just for illustration.

But in the slides 5 and 6 that you referred in my presentation, the final distribution on the very right uses all four of them, although the examples on the left and in the middle charts, they are showing that one simulation.

And all of those simulations are, as Mariko said, downscaled based on the work simulations using downscaling. And the reason we wanted to work with that is those are the simulation -- those are the only simulations we have, the latest, with the hourly granularity of the weather variables that are of interest to the study.

There are other, statistical downscale, there are hybrid downscale methods that are used and more results are coming. We haven't investigated those, but the data are the level so, you know, we're kind of trying to figure out if and how it can be incorporated to an hourly analysis, which is really --

MS. AYDIN: And I'll just add one thing for reference. If you remember, I had a slide with the bars on the number of hot days, and I mentioned that for each year, 2023 and 2050 we had constructed 120 weather variants. So, the 120 weather variants are the four GCMs, and then we use a 30-year window for each of those, and we de-trend those. That's how we get the 120 weather variants.

MS. JAVANBAKHT: Are there any other questions from folks in the room?

MR. PUSCH: Hi, my name is Alex Pusch. I'm here with Southern California Edison. My first name is A-L-E-X, last name P-U-S-C-H.

So, first question is around the selection of the four GCMs. I was just kind of curious how you guys are thinking about potential for model bias, kind of given that limited ensemble size, and whether or not you're going to benchmark that against the rest of the downscaled models?

And then my section question is for future projections why are you not considering global warming levels or have you considered global warming levels-based approaches? That's kind of (indiscernible) --

MR. AYDIN: Yeah, okay, I'll take that. I mean I don't know if Mariko and I are the best people to -- I mean, again, I think we would just definitely direct you to the people who are in the guts of the downscaling of various simulations.

Before that we started, I think those were like just the -- we could not give a climate scenario. We've been focusing on the ESSP3-7.0 as the model climate scenario. Those four, I believe, are selected based on kind of the -- we think that climate scenario had good coverage of potential outcomes.

You know, we have all the intention to add more to that dataset, but some of the limitations that we have is that the large ensemble ones that are downscaling with a different approach are available, as I mentioned earlier, so that creates some challenges. And we're trying to figure out if we can, and how to incorporate that if possible.

In terms of the biases, all of those simulations are bias-corrected based on historical observations through 2014. So, we're hoping that, you know, with some lags, you know, that the residual bias that might be left in those models are not as big as, you know, you would want to avoid.

But in terms of the global warming levels, you know, that is a big source of uncertainty, right. Just so, you know, I think one approach could be to just lock in a global warming scenario and just look at the possible range of outcomes for that global warming level. But I don't know if that helps really narrow down of what the exchange would look like because the global warming levels might be a little different. And just picking that one global warming level might be really challenging.

And, you know, that was the main kind of process we were thinking and so the --

MS. AYDIN: Yeah, so the -- right, your second -- thank you for your questions, Alex. Your second question is still something that we're exploring. And just to summarize, our selection of the four GCMs, it was really just data availability. Because, you know, these projections are still in the process of being released. So, those were the four runs that we had hourly data for.

And eventually, for demand forecasting we do need it at the hourly level. Because if we just use the daily runs, then we create more of a disconnect between the peak model and the hour, the HLM. So, we do want to focus on data where we have hourly data.

And then, in terms of how were the four GCMs selected out of all the IPCC runs, that's sort of another question. So, that's something that the Scripps, and UCLA, and UC Berkeley, they went through a process of sort of selecting which runs they'll downscale.

So, again, this might not be a satisfying answer -- but I would again point to their work because they could respond to that much better than I could.

MR. AYDIN: One thing I know is they collected the information from a variety of stakeholders about like the needs to capture, you know, the general trends of different weather variables of interest, and extremes in terms of the grid planning. And I know that they've considered that when they're selecting.

But in terms of the specifics of how they picked those four, yeah, I mean I think Mariko and I don't have the specific answer.

MR. PUSCH: And maybe to clarify the question around the four GMCs, it's less about how are those selected kind of from the climate assessment, but kind of how are you accounting for potential bias just kind of in only looking at four, knowing that there is kind of a larger set of I think 15 downscaled climate assessment, and kind of how are you benchmarking that to understand --

MR. AYDIN: Yeah, I mean -- no, okay, that makes sense. Yeah, I mean I think not all 15 of them will be downscaled, at least not at the hourly level. So, you know, we may not be able to fully benchmark that.

But I think, you know, the four, this is more like, you know, an illustration of our approach and kind of preview. As more of the 15, a larger subset of the 15 gets downscaled and becomes available, we will for sure incorporate into our analysis.

But again, each model, individually, are bias corrected with respect to the historical records. So, you know, there's that kind of anchor point to the observations that are seen.

But there is some kind of modeling, error modeling uncertainty that needs to be accounted for. And I think to address that, really what we want to do is just use as many of the models as they become available. But, you know, just do some kind of, maybe, benchmarking outside of that to see if there's any kind of residual bias from that subset of four, or eight, or however you might end of at the end of the day compared to the full 15 models that are being developed at the global level.

MS. JAVANBAKHT: Okay, thanks.

Okay, I'm going to move to -- we're about to wrap up, so I'm going to do one more question from the online Q&A, and then I'm going to turn it over to Ben for closing remarks.

So, Alex, there's a question for you from Claire Broome: How does cost effectiveness of PV for a Title 24 change under the net billing tariff, what about for multi-unit new buildings if the proposed decision for VNEM stands. And if not cost effective, will that effect assumptions about PV adoption?

MR. LONSDALE: Well, thank you for the question, Claire, appreciate it.

So, as far as assessing cost effectiveness for net billing for VNEM, that's more so CPUC's domain. And we have not looked closely at these proposed changes or how it would relate to Title 24.

I will note that the Title 24 impacts are not based -- or our forecasted distributed generation impacts association with Title 24, they're not based on an assessment of cost effectiveness. We're modeling compliance-based installations for new construction.

MS. JAVANBAKHT: Thanks Alex. We can do one more question, okay.

Then I will do, the Lumen presentations were excellent and high quality analysis. One question to help understand the source of projected increase in extremes, conceivably an increase in extremes could come from two sources. One, scaling the historical distribution of temperatures by the projected increase in average temperature. And two, a projected widening of the distribution of temperatures beyond what would be expected from the increase in average temperature. For example, reflecting changes in the climate dynamics.

I think both of these were included in the Lumen methodology, but can anything be said about the relative contribution of each to the increase in extremes?

MR. AYDIN: Well, yeah, thank you for your question, it’s really a question. So, I just want to clarify the results that Mariko and I showed today included temperature distributions based on either solely historical observations or separately based on solely climate projections. And the climate projections include kind of modeled historical period as well, but they’re all full kind of model.

And, you know, when looking at the projected changes, we see the entire distribution shifting but also, you know, getting wider in some cases. And really difficult to pinpoint which one of those two contribute the most in terms of getting extreme.

My expectation is they’re both really important. So, you know, basically getting the historical and scaling it up based on average increases wouldn’t really get you the kind of extremes that would really be seeing in the future. So, you know, you have to factor in, definitely, the potential increase in variables.

But that might just vary based on location, climate model, or the scenario that’s being considered. So, we need to look at that more carefully.

MR. WENDER: I think with that I’ll take us into the lunch break. I’ll just reflect briefly on this morning. Incredibly impressed with the breadth and detail at which you guys are working and incorporating some of these incredibly challenging questions into California's planning, energy planning processes.

I couldn't agree more, Mariko, I think California has some of the most sophisticated approaches and transparent approaches. And the questions you guys are grappling with, how should we factor climate change into our forecasting, into our planning decisions, how do we account for proliferation of behind-the-meter resources and make sure they're accounted for accurately. Just, really, nation-leading work. And learning a lot this morning. So, look forward to this afternoon.

I think I will pass it to Stephanie to give a quick remark about the afternoon session and when we'll be back. And my sincere thanks again to all the presenters this morning.

MS. BAILEY: Thanks Ben. Yeah, just a quick reminder, we'll be breaking until 1:30. So, we'll see everyone back here then for the afternoon session.

And just a quick reminder to use the same link to join for the afternoon. Thank you.

(Off the record at 12:23 p.m.)

(On the record at 1:30 p.m.)

MS. BAILEY: Good afternoon everyone, welcome back to today's Commissioner workshop on load modifier scenario development.

Again, I'm Stephanie Bailey with the Integrated Energy Policy Report team, or IEPR for short, here at the CEC.

And to follow along with today's discussion, the workshop's schedule and presentations are available on the CEC's website.

And the workshop is being recorded and a recording will be linked to the website shortly following the workshop, and a written transcript will be available in about a month.

Attendees can provide comments on the workshop by making comments during the public comment period at the end of the afternoon or by submitting written comments by following instructions in the meeting notice. And those comments are due September 1st.

Attendees are also welcome to ask questions during the question and answer period, after the presentations this afternoon.

Those participating on Zoom can use the Q&A feature to ask questions. And for those on site, staff will direct you to the correct spot.

And with that, I'll turn things over to Vice Chair Gunda. Thanks.

VICE CHAIR GUNDA: Thank you. Welcome

everybody, welcome back. I missed out a part of the morning session today, especially the amazing Nick Fugate. He complained a lot about me missing. But Nick, thank you for your work. I will watch the recording and follow with any questions I may have.

But yeah, I think I'm good to get started, a lot more information this afternoon.

Ben, do you have anything you want to add?

MR. WENDER: Just quickly say very excited to dive into it this afternoon. I think these are some of the most critical drivers of load growth and how we'll really meet our climate, human, public health protection goals. And so, the extent to which you guys can help pave the way and plan our future grid to enable that is just critical. So, looking forward to it.

VICE CHAIR GUNDA: Commissioner McAllister just got here and I know he can provide comments on the go, if he wants to. Commissioner, did you want to say anything before we get started?

(No audible answer)

VICE CHAIR GUNDA: All right, with that I will pass it back to the team to get started.

VICE CHAIR GUNDA: Thanks. Our first speaker is Ingrid Neumann.

MS. NEUMANN: All right, I hope everyone can hear me and see me. Oh, there I am. My name is Ingrid Neumann and I'm presenting on Additional Achievable Energy Efficiency, AAEE, and Additional Achievable Fuel Substitutions, AAFS, updates for the 2023 IEPR cycle.

Next slide, please. So, before we go into the forecast updates, I'd like to put out there that EAD does quite a few different types of decarbonization analyses. And sometimes that can be a bit confusing because they have different time horizons, varying uncertainty and varying uses. All of them include energy efficiency tracking or projects, as well as building electrification or fuel substitution tracking and projects.

Next slide. So, some of these are shown down on the bottom here with the timeline. We first probably came to the forefront for most of the public that doesn't follow the forecast directly with the SB 350 tracking towards the energy efficiency doubling goal in 2030. And that analysis is historic going from 2015 through protections to 2030.

Then the first time that we started doing specific fuel substitution or electrification scenarios was for the building electrification -- sorry, building decarbonization analysis under AB 3232, and that also had a 2030 deadline for GHG reductions.

Now, for the forward looking pieces which the forecast examines we have AAEE, and that's been around for awhile. AAFS was introduced as a load modifier in 2021, so that was the last full IEPR cycle.

That parallels the exact timeframe that the baseline forecast is forecast, so that's not just 10 years, but a 15-year forecast now. So, we are doing this from 2024 all the way out to the nice round year of 2040.

We also extend our analysis all the way to 2050 in support of our long-term demand scenarios so that can be used as an input for SB 100 analysis later at the end of this, and next year.

Next slide, please. So, no focusing directly on the forecast. We are proposing again to do six full scenarios of AAEE and doing six scenarios of AAFS for the 2023 IEPR. Those will range from conservative to optimistic, where the conservative one is labeled 1 and things become increasingly optimistic to a very blue sky aggressive version in 6.

Scenario 3, in the middle, is designed to be a business as usual, or a reference, or current most probably case. Note, sometimes you hear about the single forecast set and in fact that is a portfolio of scenarios for each load modifier and the baseline forecast.

So, as you heard about earlier, next slide please, there are two sets of AAEE and AAFS that will be used in combination with the baseline forecast as load modifiers to make a managed demand forecast.

One set is used for the statewide planning scenario and another set for the local reliability scenario.

Next slide. So, what exact are AAEE and AAFS? Why do we have these load modifiers?

So, the objective here is to continue to focus on firm programs and projections since the core scenarios, the ones just mentioned for these managed scenarios, will be used for planning and procurement by CPUC and CAISO.

As in previous iterations, staff will develop variations around these most probable futures to show other possible outcomes, ones that are more conservative and ones that are more aggressive, given less or more effort and the ability to realize the potential of existing or proposed energy efficiency and fuel substitution programs.

AAFS continues to be conceptualized separate from AAEE.

Next slide, please. So, we get a lot of

questions about how these work. And we do make sure that any overlap between these load modifiers, as well as the baseline energy demand forecasts are accounted for. Only achievable energy efficiency savings or fuel substitution impacts that go above and beyond that which is already incorporated in the baseline energy consumption forecasts are retained. So, everything is counted once and only once.

Next slide. Both AAEE and AAFS reduce gas consumption. Right, our demand forecast includes gas, as well as electricity.

On the electricity side, AAEE also reduces electricity consumption. But AAFS increases it. Thus AAEE is called savings and we're using impacts for AAFS.

Both load modifier increments and decrements are always relative to the baseline electricity an gas consumption on an annual basis.

For electricity, is it also modified by both AAEE & AAFS on an hourly basis.

Lastly, AAFS may contain both programmatic inputs, which I will talk about, as well as technology-based fuel substitution which is modeled by the FSSAT, which will be described in the subsequent presentation by Ethan Cooper. That was suggested in 2021, but it wasn't implemented at that time. We are, however, doing so for 2023, for the 2023 IEPR cycle.

Next slide. So, we're going to look at a bit of the general approach to how we might develop the scenarios and what goes into them, and how much of the penetrations go into the different scenarios.

So, we have six scenarios and if we start from the bottom with the most conservative, that would include something that we would call firm commitments. These are existing programs and standards that are not yet incorporated in the baseline forecast. That's our most certain AAEE or AAFS scenario.

Next slide, please. Then we add some newly existing programs. Those definitely will occur, but there is some uncertainty around the impacts.

Next slide. Scenario three, which is our business as usual, will include newly developed and funded programs that maybe haven't started implementation yet, but they are planned for the future. They are in process, they're reasonable to occur, but there is some uncertainty about the penetrations or the volume of impact or savings.

Next slide. Then we start taking a blue sky view of these things. So, the first -- or the fourth scenario here, where we're starting to get a little optimistic, we're taking everything that we see in the first three scenarios and we're ratcheting up compliance rates, participation, and incentive programs, market adoption and funding, and just taking an optimistic view of this likely to occur.

Then the fifth scenario, on the next page, would start adding more speculative programs. So, these might be things that are in the early planning phases but haven't been completed. These programs might help meet minimum GHG reduction goals, such as those under AB 3232 or SB 350 doubling. But, you know, they are a glimmer in someone's eye.

Lastly, on the next slide, we would start including all possible achievable energy efficiency and fuel substitution. So, programs that could exist in the future and that would be required to meet some of our policy goals. Perhaps this would help us reach our midcentury GHG reduction goals. But this is very optimistic, very aggressive, including everything that's possibly achievable.

The next slide has a summary of all the scenarios, so that one's nice to look at in summary.

And then, we'll go on to the next slide, please. So, for 2023, as we're developing the programmatic components of AAEE and AAFS we are using an updated and enhanced version of the savings accounting, aggregation, and extrapolation methodology and tools that were previously employed for the 2021 IEPR.

All historical data and potential savings projections were or are being updated in existing workbooks.

New workbooks are being added on recent programmatic activities.

And then in the tool itself, we have added building type disaggregation or subfactor, as well as forecast zone output capability.

We've also added basic cost calculations for each scenario, so the value of various energy efficiencies and building fuel substitution impacts can begin to be quantified.

Some of these are pretty good estimates, others are very high level. But the hope is that we can at least get some order of magnitude quantification here. And, of course, as with all of our pieces this is always an iterative process where we update and enhance every cycle.

We have also been working on enhancing the input data, as well as the software tools depending on which part makes the best sense to work on to allow for better extrapolation of potential savings to the midcentury. So, we do have to go out to 2040 for the forecast, but then we're going beyond that for the long-term demand scenarios.

So, let's go to the next slide. This gives us a little bit of a flow chart on what the process is for the data integration tool and our three big chunks of data.

So, in the middle we have the CPUC's Potential and Goals Study that gives the IOU program projections. And that is updated every two years on cycle with our entire demand forecast updates. So, we have fresh data for 2023 and we usually develop those scenarios, and do propose doing so this cycle, around the proposed goals scenario, so what's now the proposed goal.

For the CMUA, they also do a Potential and Goals Study for the POU projections. That is done every four years. So, we are still using the same underlying data as was submitted in their report in 2021.

Then, the last bigger box on the bottom is where the Energy Commission has a bunch of different workbooks where there is separate analysis for each of these Beyond Utility Programs. And that includes codes and standards integrate part, and we have the first year projections modeled for all of those for 2024 to 2040.

Next slide, please. There is a little bit of interaction between those Beyond Utility workbooks and the CPUC's Potential and Goals Study. Mainly, that's for the federal planned standards in Title 20. We always seek to use the best source of data and sometimes that's in our Beyond Utility workbook and other times that's from the Potential and Goals Study.

As I'll mention later, the Title 24 Building Energy Efficiency analysis was completed updated for the 2023 IEPR cycle. So, that lives in our Beyond Utility workbooks.

So, you can see that we need to extrapolate the 10-year Potential and Goals Study out to 2040, and that's where we're actually looking at enhancing that input data, and not doing that in our tool separately, because the CPUC and the IOUs understand their programs best.

Fortunately for POU programs, what they submitted in 2021 already went out to 2041. So, we can take that data directly and develop scenarios around that.

Next slide, please. So, finally, we put all that together in our data integration tool and we have total cumulative projections for AAEE and AAFS for the forecast period by utility or forecast zone, sector as before. Now, we've added the building type. And then, end use and scenario as before.

For the electricity portion we apply the load shapes to get full 8760 hourly outputs for both energy efficiency and fuel substitution load modifiers at the same level of disaggregation.

So, some additions and enhancements here for 2023. We've included a more robust analysis of Beyond Utility programs, so again those are the programs not run by the IOUs or POUs, or not reported by them, that were originally evaluated in the 2021 IEPR.

Notably, the technology and equipment for clean heating or TECH program, as well as consideration of additional programs that were not included in the 2021 IEPR, mainly because they didn't exist yet.

So, a couple of those. Ah, before we want to mention reworking the Title 24 analysis. So, when these -- when this work was originally conceived, it was done as a percent better than approach, so present better than the previous code cycle approach.

And we've revised this to be more detailed so that the Title 24 building energy efficiency standards analysis is based directly on the measures at the sector and segment level.

So, this measure-base analysis not only can be more easily rolled forward as specific measures are adopted in future code cycles, but it can also be better disaggregated by end use.

So, we've also updated the compliance pathway that is deemed most likely to be chosen by builders to meet the 2022 Title 24 requirements. As a reminder of those options were either enhance energy efficiency measures via a performance calculation that's existed in many code cycles for Title 24, but in 2022, which that code has been in effect since January of this year, the other option was to choose electrification measures based on building climate zone. So, definitely encourage that.

So, we have a better separation as to what goes in the AAEE an what goes into the AAFS. And, of course, that will be updated as, you know, that EMNV on that data is done, but it's only been in place since January of this year.

Next slide, please. So, we've added some new workbooks. Some notable ones are the Equitable Electrification workbooks. There are two programs there that are currently being developed in the Efficiency Division of the Energy Commission. One is a direct install program and the other one is an incentive program.

And then, there's the Clean Energy Reliability Investment Plan funded program, which are also being developed, and maybe are a little bit less far along, but should have some impacts here. So, some people know those by their fun acronym, CERIP.

Then, in the second bullet, the Federal Inflation Reduction Act has two programs, as well, the High Efficiency Electric Home Rebate Act, or HEERA, and the Whole House Homeowner Managed Energy Savings, or HOMES, Program. And those, we've developed workbooks for those as well, and we'll update those with more information as the details come out, and as the programs are then implemented. But at least we're counting them for 2023.

Something that we've been working on, which maybe doesn't have the largest impact, but is really interesting, are the locally targeted electrification impacts that can be driven by government ordinances, or load-serving entity decarbonization programs. So, these are more geographically targeted electrification initiatives that thus far might have small impacts, but if they spread they would have larger impacts, and they matter quite a bit for some of the local reliability work.

Next slide, please. So, this is a list of elements to be included. We're kind of putting them into the scenarios and doing some preliminary runs, and filling in, you know, some of the data still. And we'll have a workshop in November where those results then are presented.

We might be a slide behind. Next slide, please. There we go. All right, so we mentioned the IOU programs, right, that come from the 2023 CPUC Potential & Goals Study. Then, some other IOU data that's pulled directly from the CEDARS database helps us with fuel substitution activities, especially for CCAs and REMs that aren't, you know, captured in the Potential and Goals Study yet.

Then, we have the CMUA Potential Study for the POU Programs. And we're conducting interviews again with the POUs on their recent fuel substitution activities, so we can update those workbooks.

And, of course, future Title 20 and Federal Appliance Standards, it looks like there's going to be some movement with the Federal Appliance Standards there in the near future, one can hope. So, we're always looking for more energy efficiency, right.

And then, of course, the updated Title 24 analysis, with 2022 and beyond.

And then, as Ethan will talk about, we are also including zero emission appliance technology characterization modeled via the FSSAT, which includes

CARB SIP regulation. So, that's the state implementation plans, so we'll have different variations of that, as well as other more local initiatives by the Air Quality Management District.

As I mentioned before, the local ordinances encouraging electrification of some or all end-uses, as well as other targeted electrification including local natural gas bans are also being analyzed.

Then, of course, we have a lot of other bread and butter type of traditional energy efficiency programs that exist outside of the Utility EE Programs. The BUILD and TECH programs, CERIP as I mentioned before, the California Electric Homes project, the CalSHAPE for schools, the wildlife -- wildlife? Okay, so the WNDRR, and I -- it's the resiliency of like wildfire. See, it's wild something. I don't know. I'm just thinking of like fuzzy animals. I'm missing my cats that usually are my office mates.

All right. So, I'm looking, it's the Wildfire and Natural Disaster Resiliency Rebuild Program. So, that is a program that targets folks who have lost their homes in that type of situation. It's a $50 million over ten years. And it promotes all-electric rebuild.

So, if you are going to rebuild, at least let's do it in a way that limits are GHG emissions that, you know, caused all that climate change the wildfires to begin with.

And then, we have the IRA-HEERA & HOMES, and the Equitable Building Decarbonization Programs, the Direct Install and the Incentive Programs.

So, a little bit more on the next slide. So, this is a reminder of the program -- of the process flow. So, we end up in the orange box on the top right with the total cumulative projections for each year.

And what that really looks like, then is we would get a grid that would be difficult to read on a screen like this, maybe on the big screen in the room here it's possible to see on the next slide, when we have our final scenarios.

And that would have the different levers that we could pull for the IOU potential program savings, as well as the POU potential program savings, as well as the different codes and standards, and the different vintages of those codes and standards, as well as the 40 odd Beyond Utility Program Savings workbooks that we would included here. So, that's for all the programmatic pieces.

And then, we would layer for AAFS the FSSAT modeling on that to have a complete AAFS scenario.

So, what I'd like to highlight on this slide are the yellow scenario two and scenario three. Right, those are the ones that are used for the core planning processes, whether it's statewide for scenario three and local reliability for scenario two, on the next slide it's the same approach for the AAFS.

And instead of using less fuel substitution penetration, it was determined in 2021 that it really made more sense for a conservative electricity planning scenario, which should be the local reliability one, to include a slightly higher fuel substitution penetration, which is w why there's a circle around scenario four. And that's what we're proposing this go around as well, and as I'm sure you've seen in our general forecast slide previously.

Next slide. So, some of this can be a little confusing as to what happened when, so put together three pieces here as far as what we did in the full update in 2021.

We had the six AAEE scenarios. Those have been around for a while. And we had a Statewide Planning Forecast that included the scenario three for both energy efficiency and fuel sub. Fuel sub was new in 2021 and there were only five scenarios, so that's what

I've highlighted here. And the reason for that was that there were some few programs at that time, the impacts weren't particularly big. So, having something with -- something that had a scenario one, which was extremely conservative, really wouldn't have been different than a scenario two, so we decided not to develop that.

All right. So then, as I mentioned before, the local reliability scenario had the AAEE 2, as has been the case for a while, and then we determined in 2021 that a slightly higher fuel substitution penetration made sense for a conservative electricity planning scenario.

So, the next slide. Now, we usually do not do an update, and it's not our intention to do that normally in the interim years. So, the even years of the IEPR cycle for the load modifiers. But what was different here is that CARB did pass their State Implementation Plan, and that has significant impacts, especially after 2030.

So, we did want to include that for local reliability, so that was layered on top of the existing 2021 scenarios for AAEE and AAFS. So, that was layered on top of AAFS 4 in some ways.

So, what we're doing in 2023 is we're fully incorporating that with our analysis so it doesn't look like, you know a separate thing. It was just we didn't want to be misleading. And we didn't update any of our programmatic pieces, you know, so we were just adding that SIP modeling there.

So, here we are on our next slide. So, proposed for 2023, right, the six AAEE scenarios, six AAFS scenarios, and then for the planning forecast, you know, it's the same, three and three. But AAFS 3 will now include some FSSAT SIP modeling that Ethan will go into. And one, maybe more conservative version than the one that goes into AAFS 4, for the local reliability scenario.

So, moving on to some of the last slides I have here, of how those are all integrated to the managed demand forecast scenarios. So, this is just looking at 2023, pretty much a copy of what was in that third bubble on the last slide.

And the next slide, please. What's really different here, and I don't want folks to get confused about, is that the AAFS scenarios are now going to be inclusive of FSSAT SIP modeling or other zero emission appliance standards modeling that Ethan will go into.

So, I also want to point out that AAEE electricity and gas savings can be separated. AAFS, electricity and gas cannot, right, because the gas really is being displaced and substituted by some electric or electricity-using technology.

So, we do prioritize fuel substitution over energy efficiency in our work because the GHG impacts are approximately four times greater for fuel sub, than for energy efficiency.

And the way that we do this is on the next slide. Also happens to be my last slide.

So, we start with the baseline gad demand forecast and we remove the gas displaced by the programmatic fuel substitution. So, like things like the Tech Program, Equitable Electrification, et cetera, and all of those programs in there.

Then, we apply the technology based fuel substitution, modeled by the FSSAT that Ethan will go over, which includes the State Implementation Plan scenarios.

And what can happen then is it's possible to exhaust gas consumption in certain sectors and end uses. So, we don't apply the energy efficiency pieces until the end.

So, in the case that some energy efficiency can't be realized, we would modify our AAEE gas scenario, then. So, it's definitely only displacing it once and we're keeping everything realistic there.

So, that is all for me. The final slide has my email on it, if folks want to send me a question. And, of course, we're taking questions and comments right now, as well, or I'll go -- the docketed comments, right, for the workshop. Thank you.

COMMISSIONER MCALLISTER: Thanks a lot, Ingrid. I'm just going to just go first and go quickly because I have to step out for a call.

But thanks for that. It was really a very complex mosaic of sort of data analysis that you're, you know, managing to bring together and integrate into one whole that I think hopefully, you know, both we and the world can follow.

I wanted to make sure we just get on the table, you know, the aggressive goals we have for heat pumps, the 6 million heat pump goal by 2030, and the three in 7 million climate friendly climate-ready homes by 2030 and 2035, respectively. Which are aligned, basically as, you know, parallel goals for the state. So, interested in how that all fits into the scenarios.

And secondly, I want to just highlight that, you know, what the 3232 Study found was that, you know, absolutely electrification, and specifically heat pumps, are really the only scenario, the only kind of path that gets us anywhere close to our buildings related emissions goals.

But actually, also, not just any heat pumps. Really, the best bet is efficient heat pumps. And so, you know, wanted to just make sure that that nuance is in there. You know, not just any minimally compliant heat pump, but actually try to understand the incremental benefit of going for the highest tier of efficiency of heat pumps. And I think that makes -- that will make some difference, certainly in the cost landscape for the system overall. So, just wanted to sort of put that in and make sure it's getting covered in your analysis. And perhaps even some sort of text or verbiage around that distinction.

But really, really appreciate the overview of the AAEE and AAFS. Really key components of our demand going forward. Thank you.

VICE CHAIR GUNDA: Commissioner McAllister, before you jump out, are you suggesting, so we've -- on the transportation side, at Commissioner Rechtschaffen's request, we considered –the additional achievable transportation. We took the scoping plan and then baked it into our forecasting for RA purposes -- for IRP purposes. Are you suggesting that we ensure that the 6 million heat pumps in the climate-ready homes are baked in for the resource planning?

COMMISSIONER MCALLISTER: I mean ideally, yes. I mean I can't -- I don't think we are in a position to say, you know, we're absolutely going to knock it out of the park and meet that goal on the year. I mean I think the scale up in heat pumps that has to take place to meet that 6 million goal is pretty -- is quite aggressive. So, you know, we're trying to develop that marketplace. We're going to pump a lot of money into the sector and we're talking with all the OEMs to make sure the supply chain's there. So, you know, we're doing all the due diligence to help realize that goal.

But I certainly think there should be a scenario that does encapsulate meeting the goal, you know, a policy scenario. And then, sort of, you know, see where that falls within the spectrum of the various scenarios you just talked about.

VICE CHAIR GUNDA: Thank you.

COMMISSIONER MCALLISTER: I'm certainly not going to say that we're not going to meet the goal. Because I do have faith that we will. But I just want to make sure we're starting where we are.

MS. NEUMANN: I think the incentive programs are being designed with that in mind. I think where there are some issues is with the SGIP modeling, because if you could -- you could certainly require something that has a certain minimum NOx emissions but that doesn't really look at the efficiency of the heat pump or not.

COMMISSIONER MCALLISTER: Right.

MS. NEUMANN: But that's where there might be some movement in the Federal Compliance Standards by the time that becomes reality. So.

COMMISSIONER MCALLISTER: Possibly. I guess the, you know, the SGIP is going to make sure -- you know, we can do all the new buildings and get all those heat pumps, and that will get us to a certain portion of the goal. But, really, existing buildings and change outs are where the big action is going to have to be to meet that goal.

And, you know, we're holding hands tightly with the Air Resources Board on development of the zero emission rules for HVAC and water heating. And, you know, effectively that means electrification, it means full on heat pumps. And if that happens by 2030 which is, you know, their goal, and actually parts of the state are doing it more quickly than that, I think that will give us a really strong chance to meet the overall 6 million goal. And that definitely ought to be built into a planning scenario for sure.

VICE CHAIR GUNDA: Thank you, Commissioner McAllister.

Just I think following up on that, maybe you'll go into this, Ethan. I think I would really appreciate, both from our JASC colleagues, right, CAISO and PUC, but also the DAWG where we, you know, have the benefit of having the IOUs be a part of that, just kind of having the discussion on -- and, obviously, it will be in the policy scenario, but how much do we really want to bake that into -- you know, into the modeling for the IRP purposes, and all the purposes, right.

I think what I continue to feel is we need to be a little bit more conservative, meaning higher electric load for a while, rather than on the other side, especially the next several years of uncertainty.

This morning we had that wonderful discussion on the climate impacts, so that's one big uncertainty. But the electrification uncertainty especially, you know, geographically, right, that goes into local reliability constraints.

I would recommend that we strongly push for, you know, being on the more conservative side of having more electricity on the system and thinking that through. And would love to hear in a public setting, you know, what this discussion's yielded, and kind of justifying where and how we're going to move forward. Thank you.

Well, Ben doesn't have questions, so I'm going to just say awesome presentation. Ingrid, I really enjoy how you've taken this extremely complicated rubric of terminology, and we used to have this chaotic menu of things we do, and nicely kind of continue to bucket them in a way that it's understandable. So, really appreciate that. Thank you.

MR. GEE: Great. Thanks everybody. Hi, my name's Quentin Gee. I'm the Manager of Advanced Electrification Analysis Branch here at the CEC. And I'll be taking over the mic from Stephanie from here on out.

But thanks, Ingrid, for your presentation. And I think now we're going to move it on to Ethan, Ethan Cooper, Associate Energy Specialist in the Advanced Electrification Analysis Branch, talking about incorporating zero emissions standards into AAFS. Ethan, thanks.

MR. COOPER: Yeah, can everyone hear me. Okay, that sounds like it works.

All right. My name is Ethan Cooper and today I'm going to be -- let's move this over here -- going over our inputs and assumptions for incorporating CARB's Zero-Emission Appliance Standards into our various AAFS scenarios that are being developed for our 2023 IEPR.

Next slide, please. So, looking at a bit of a background on some of the emission standards or rules that we are expecting to be including in our modeling process this year, we started based off of are they like an emission rule that's going to be applied to the (loss of audio) -- Yeah, so we decided to split them up -- if there is going to be a proposed measure that's going to be effective for, you know, the statewide as a whole or if it's going to be just going to like a local area or jurisdiction, like an Air Quality Management District.

So, starting with looking at the Statewide Emissions Standard that we are looking at modeling, which is the major component of our modeling this year, is going to be looking at CARB's Zero-emission Appliance Water and Space Heating Standard which was proposed in their 2022 State STIP strategy. STIP was the State Implementation Plan

This Emissions Standard was looking at creating a rule so that way in 2030 all new space and water heaters sold in California, for either new or existing buildings would have to meet a zero emission standard.

And this rulemaking process for this standard started earlier this year, and CARB had the first workshop on it on the 10th. And the rulemaking is expecting to be going to the CARB Board in 2025 for adoption.

Moving on from the Statewide Emissions Standard we're looking at, we're also looking at any local emission rules or measures that may be going into effect before CARB's Emissions Appliance Standard that starts in 2030.

The first one that we're looking at is the proposed Regulation 9, Rules 4 and 6, of the Bay Area AQMD that are looking at space and water heating appliances. This -- yeah, this zero emission -- or zero emission rules for the Bay Area were adopted by the Air District earlier this year in March.

And as what the rules are, Rule 4 is looking at creating a zero NOx appliance standard for natural gas-fired space heaters. So, that would begin in 2029.

And the Rule 6 is looking at creating a zero NOx emission standard for natural gas-fired water heaters, which was started in 2027 for smaller water heaters and 2031 for larger water heaters.

Next, moving on to the South Coast AQMD's low- and zero-emission control measures. These are control measures that are implemented by or proposed in South Coast's 2022 Air Quality Management Plan, or AQMP. And these are measures that will be applying to multiple end uses, more than just water or space heating.

But for the purposes of our modeling, in our tools we're only going to be looking at the control measures for the residential sector.

And the control measures here that we're talking about, these are looking primarily at creating either rules or other strategies that would help with shifting, or I guess and to encourage or mandate the moving from natural gas-fired appliances for HVAC, water heating, cooking, and then other end uses, miscellaneous end uses over to zero- or low-NOx alternatives starting in 2029. And when I say miscellaneous, that means other end uses in the residential sector, such as clothes dryers.

So, these are the different statewide and local mission rules or standards that we're planning to model for our 2023 IEPR. And the tool that we're using, which I'm going to go into in the next slide, is called FSSAT.

Next slide, please. So, for our building decarbonization this year, of CARB's Zero-Emission Appliance Standard, we are going to be using the Fuel Substitution Scenario Analysis Tool, or FSSAT. This tool has been used previously for prior assessments done in the CEC, it's been done, it's been used for the AB 3232, California Building Decarbonization Assessment. That was adopted in 2021. The Demand Scenarios Project that was adopted in 2022. And the 2022 IEPR Demand Forecast Update that we worked on last year.

So, we classify FSSAT as a “what if” policy analysis tool which looks at examining both the cost, energy, and greenhouse gas impacts of various fuel substitution scenarios, with each of these different scenarios having their own levels or assumptions about what the additional achievable energy efficiency, AAEE, or fuel substitution, AAFS scenarios are going to be.

And for our iteration of modeling CARB’s Zero-Emissions Appliance Standard we are going to be using some of the same technology set of assumptions that we used for prior assessments, for both the 2022 IEPR Demand Forecast Update, as well as the Demand Scenarios Project, and the AB 3232 assessment.

So, last year as we said, in this slide, we were able to use the FSSAT tool to model the impacts of the Zero-Emissions Appliance Standard for the 2022 IEPR update. This was the first time we used the FSSAT tool to provide any load modifier impacts for the demand forecast.

And we were able to use the tool to model both the gas savings, as well as the added electricity impacts of the Zero-Emission Appliance Standard. And they were used as load modifier, alongside with AAFS Scenario 4, as part of our local reliability scenario for the 2022 IEPR forecast.

So, these are the assumptions -- so, this is the tool that we're using and kind of how it's been used previously.

And now, we're going into the next slide about some of the updates that we are doing to our assumptions for the Zero-Emission Appliance Standard in the FSSAT tool for our 2023 IEPR.

So, on the table here, we can see that the major update that we're doing this year is that rather than having the Zero-Emission Appliance Standard modeling for just a single scenario within our demand forecast, instead of just being modeled for AAFS Scenario 4, like what was done last year, it's going to be modeling into four various AAFS scenarios. That would be AAFS scenarios 3 through 6.

So, on this table here we can see the column headers dictate which AAFS scenario we're at including the Zero-Emission Appliance Standard into.

And the rail headers, under AAFS Levers column, shows what different programmatic or technical levers we're able to pull on our FSSAT tool in order to change how we're going to be modeling the Zero-Emission Appliance Standard amongst the four AAFS scenarios.

And the boxes on the far left, the dark blue and the dark green boxes, those dictate whether or not our

AAFS scenarios are looking at our programmatic characterization of our AAFS scenarios, so for AAEE or AAFS programmatic impacts.

And then, the green box looks at our zero emission appliance technology characterization, so anything that we are modeling in FSSAT for our Zero-Emission Appliance Standards, as it is modeling in each AAFS scenario.

So, going down the line about what each level is, so for the first two rows, the light blue and light green, these are looking at our levers to dictate which AAEE or AAFS programmatic scenario we're going to be including in our modeling for the AAFS scenario in the column headers.

And then, below that these are our first dark green boxes. These are what the toggles that we choose in FSSAT to dictate how we're going to be modeling the Zero-Emission Appliance Standard.

So, the first three rows deal with looking at are we going to have the Zero-Emission Appliance Standard only be applied to water heating and space heating end uses, or we could also have it be applied to other asset end uses which include cooking and clothes drying that we were able to model in our tool. And/or we could be looking at the fuel substitution of residential propane equipment, and that would just be for HVAC equipment or water heating equipment.

Now, the next level below that, called AQMDs, that's looking at are we going to be including any of the more local emission rules from the AQMDs that we discussed in the previous slide, which is are we looking at the Bay Area or the South Coast proposed emission rules or measures.

And below that our technology set lever. That let's us determine, you know, how are we viewing what technologies are going to be available to replace gas equipment for every end use. Are we going to have a mixture of available technologies that are going to vary by efficiency, or are we only going to allow a single best efficient appliance available be available to replace gas stock.

And then below that we have our technology weighting efficiencies. These are how we determine are we going to prioritize higher efficiency appliances or lower efficiency appliances when we have a mixture of available technologies to replace gas equipment.

And then below that, our last lever is called a ramp up adoption rate.

VICE CHAIR GUNDA: Ethan, just one --

MR. COOPER: Yeah.

VICE CHAIR GUNDA: -- just a quick clarification on this one.

MR. COOPER: Yeah, go ahead.

VICE CHAIR GUNDA: So, the AAFS 1 and 2, they are not here, right, so that we had talked about 6. And then those two, what are the levers for those?

MR. COOPER: We are not going to be having AAEE or AAFS 1 and we're not going to be having AAFS 2 be included in here. So, they're not -- only -- the Zero-Emission Appliance Standard is only going to be applied to these four scenarios, so they're not going to be applied to anything. It's not going to use any AAEE scenario 1 or AAFS scenario 1, and no AAFS scenario 2 for the assumptions.

VICE CHAIR GUNDA: Got it. And then, just kind of a clarification. When we're talking about other FSSAT end uses, like what's the rationale not to have it for 3 and again? Sorry, I didn't track it well.

MR. COOPER: I think these 3 and 4, just what is the current proposal for CARB's Zero-Emission Appliance Standard, which is just looking at water and space heating. But 5 and 6 is going to be looking at in a more, I think as Ingrid said, high in the sky future. What might happen if that regulation goes into being effective for other end uses, such as cooking and clothes drying, and then how will it look if all of it goes to propane fuel substitution.

VICE CHAIR GUNDA: But the rationale, I think, is like because it's not yet --

MR. COOPER: Yeah, they're not yet done. They're still in their rulemaking process. So, if that may happen in the future that they actually do want to go to those end uses, then that would be included in those lower scenarios.

VICE CHAIR GUNDA: And then, also, are we tracking the other AQMDs' work and proposals?

MR. COOPER: We're looking into them, but right now we just have what is currently either the AQMD's are starting a rulemaking process for any of their proposed measures, or anything like the Bay Area that has already adopted their proposed rules. So, we're looking at any more AQMDs that we could possibly include in the future for those more higher scenarios, AAFS 5 and 6.

VICE CHAIR GUNDA: Okay, thank you.

MR. COOPER: Yep.

MR. WENDER: So, maybe can I jump in with one more --

MR. COOPER: Yeah, go ahead.

MR. WENDER: -- just since we're looking at this. Within the technology set that you consider, what are the ranges of efficiencies for the different types of appliances and, yeah, how are those updated, or tracked, or benchmarked against what's available in the market and how the market's progressing?

MR. COOPER: Yeah. This year, when we're working with our consultants to try to update all the technology sections that we have, but currently we have some -- we don't -- I don't know the specific efficiencies, but we have stuff that ranges from like electric assistance water heater to a less-efficient heat pump, to a most-efficient heat pump. So, that's kind of our array of technologies that we have included.

But we have pointed out that this year for the next, I guess, 2025 iteration of this modeling. Yep.

All right. I think I'm on ramp up adoption rate. So, this is the last lever that we have. This is kind of our toggle to choose what are we going to expect the ramp up adoption going to -- or, I guess that's the same thing. What are we expecting the electric appliance adoption is going to look like in the interim years before we reach any of our targets for either the Bay Area or South Coast, or for the CARB's Zero-Emissions Appliance Standard in 2030.

This kind of gives us a good idea about what are the interim years going to look like about adopting electric appliances in lieu of natural gas ones. It helps us, that way we aren't just going from like zero to a hundred percent ramp up from one year to the next, when we go from the year before the standard or rule that comes into effect to the year that it does come into effect. That's just kind of what we're choosing there for that last toggle.

So, with that I'm going to go onto the different toggles we're choosing in each scenario. So, for AAFS scenario 3, which is going to be our planning scenario, we're choosing to use programmatic AAEE scenario 3 and programmatic AAFS scenario 3 in our FSSAT modeling.

And then below that, we are going to have it so that way CARB's Zero-Emission Appliance Standard is only going to be applied to the water heating and space heating end uses. It's not going to be applied to cooking or clothes drying, and it's not going to be applied to residential propane fuel substitution.

And then after that, looking at our AQMD lever, we are choosing to only include the adopted zero emission rule for the Bay Area AQMD into our modeling for this scenario. As their technology sets, we've seen that there's going to be that mixture of efficient technologies available to replace gas equipment for every end use, ranging from AV electric resistance to a most efficient heat pump.

And then, for technology efficiency weighting, we are going to be evenly prioritizing each of the technologies equally, which means that if there were like two appliances to replace the gas HVAC space heater, we would assume that 50 percent of those appliances replacing that gas heater would be the most efficient heat pump, and then 50 percent of them would be the less efficient heat pump. So, that's kind of how we view the evenly weighting being.

And then, finally, for ramp up adoption rate, we are going to have a linear ramp up similar to what we had last year, where we kind of have a nice linear trend going up into target dates for either the local areas or for the whole statewide standard.

However, we are going to have a 10 percent reduction in the interim years for the ramp up adoption we're going to be having for just statewide adoption for CARB's Zero-Emission Appliance Standard.

And that's only going to be a reduction for this scenario. It's not going to be seen in any of the other scenarios, AAFS 4 through 6.

All right, moving on to the next scenario, AAFS scenario 4, which is used for our local reliability scenario in the forecast. We are now going to be choosing to use programmatic AAEE scenario 2 and programmatic AAFS scenario 4 as our choices for the programmatic impacts in this scenario.

And all the different levers in the green boxes are pretty much the same between AAFS 4 and 3, with the only difference being that AAFS scenario 4 now has a linear ramp up without the 10 percent reduction rate in the interim years.

So next, moving on to AAFS scenario 5. This is our -- this is the beginning of our most aggressive scenarios. This one's going to be using programmatic AAEE scenario 2 and AAFS scenario 5 to provide our programmatic impacts for this AAFS scenario.

And then below that, the only difference between AAFS scenario 5 and 4 in the green boxes is that this is where we start to now have the Zero-Emission Appliance Standard be applied to water heating, space heating, and to cooking and clothes drying end uses, and now also be applied to residential propane fuel substitution for the HVAC, and water-heating propane appliances.

However, besides that there's no difference between AAFS scenario 4 or 5.

Now, going on to the final, most aggressive scenario, AAFS 6, we are now using programmatic AAEE 2 and AAFS 4 to provide our programmatic impacts for that scenario.

And in the green boxes, the only difference between AAFS 6 and 5 is that AAFS 6 now is including the South Coast AQMD's proposed zero low emission measures into the assumptions that we have, so it's going to be included alongside what we already have for the Bay Area.

And then, for technology set choice, we now have it so that there's only a single most efficient technology available to replace gas equipment for every end use we have in FSSAT. And that's going to make it so that way our technology efficiency weighting assumption or lever is no longer applicable because we do not have a variety of efficient technologies now. Have to wait to see how many most efficient technologies are going to be replacing gas versus the less efficient ones.

So, that is all of our different assumptions that we're going to be having for the Zero-Emission Appliance Standard modeled into the AAFS scenarios.

And one other thing to note here is that we consulted with CARB staff to go work on creating these characterizations and assumptions that we have in the tables on this slide.

So, next slide, please. So, the table in this slide is looking at what are our adoption assumptions actually going to be in this FSSAT tool. So, these adoption assumptions look at how we are viewing the adoptions of putting in electric appliances in exchange for gas equipment, and how those adoption assumptions change based off what territory we're looking at. Are we looking at just, you know, CARB's statewide emissions standard, which is the all the districts category, or are we looking at just any of the measures or rules in the Bay Area or the South Coast AQMD territory.

We also have a building type distinguisher here, which is are we looking at this -- is this assumption just for new construction buildings or is it for existing buildings.

And then, we have the AAFS scenario column to let us know if this is an adoption assumption just for all AAFS scenarios or just for a select few of them.

And we have our row headers, which are basically the percentages in all the different row column headers. Those are basically saying for that given year, what percent of appliance replacing gas equipment are going to be electric.

And we have that for 2020 to 2025 it's always going to be zero percent. It is not -- we're not going to have any adoptions starting until 2026, which is the year after we expect the CARB Zero-Emission Appliance Standard to be adopted by the CARB board.

So, looking first on what we have for new construction. So, for all our districts and for all AAFS scenarios, we are going to assume in our modeling that for new buildings they're all going to be electric starting in 2029 for commercial buildings, and they're going to be all electric starting in 2026 for residential new buildings.

Going now into our existing buildings -- oh, so one more thing to note here is that the different color coordination, the green colored boxes, light and dark green are for gas to electric fuel substitution, and then the blue ones are for propane to electric fuel substitution. That's how we had to distinguish the two fuel types here.

So, going into our next, our four dark green boxes, these are looking at our adoption assumptions we have for replacing burned out gas equipment with electric appliances. We're looking first at our assumptions for all our air districts, besides the Bay Area or South Coast, and for AAFS scenario 4 through 6 we have electric appliance adoption rate of 20 percent starting in 2026, and that's going to go up by 20 percent each year until we get to 100 percent in 2030.

And in parenthesis, we have what we assume is gong to be the adoption rate for AAFS, which is showing it's 10 percent lower than what we have for AAFS 4 or 6 -- 4 through 6, sorry.

Next moving into our assumptions we have for the local air districts. For the Bay Area AQMD, our assumptions we have for just HVAC equipment is that starting in 2026 we're going to have electric appliance adoption rate of 25 percent. That goes up by 25 percent each year until 100 percent in 2029.

And then, for the water heating end use, we added that, so we have adoption -- an adoption rate of 50 percent in 2026, that jumps right up to 100 percent in 2027.

Lastly, for the South Coast AQMD, we're looking at just -- and this is for residential -- all residential end uses, and this is just for AAFS scenario 6, our most aggressive scenario. We're going to assume that for South Coast in 2026 we have an electric adoption rate of 25 percent in that year, which goes up to 100 percent in 2029.

And then finally, our last two dark blue rows, which is our propane fuel substitution and that's only going to be applied to AAFS scenario 5 through 6 for all the districts, and looking at propane replacement of existing -- sorry, replacing burned out gas equipment and existing burned out propane equipment in existing buildings. We're going to assume that we have an electric adoption rate of 20 percent in 2026. That goes up by 20 percent each year until 100 percent in 2030.

And then, if we're looking at all air districts, propane replacement in just new construction buildings, we are again going to see in 2026 all buildings are going to be electric in that year, so no longer are we going to have any propane equipment being installed in those buildings.

So, this is the adoption assumptions that we're going to be having in our FSSAT tool for modeling the Zero-Emission Appliance Standard in our 2023 IEPR forecast.

Next slide, please. All right, so finally here we're going to look at just what our expected energy impacts are going to be of our various versions of the Zero-Emission Appliance Standard, which is modeled -- which we're modeling in FSSAT.

So, first looking at our gas savings from the FSSAT modeling, we expect that they are going to be increasing by each AAFS scenario, which means that AAFS scenario 3 we have the least amount of gas savings, and AAFS scenario 6 we have the most amount of gas savings.

However, for electricity -- so, for added electricity, however, from the FSSAT modeling, those -- the electricity is going to be increasing differently amongst each AAFS scenario. But it actually is going to be increasing differently amongst the last two AAFS scenarios and this is because AAFS scenario 6 is assuming that we're only going to have a single best or most efficient technology available to replace a gas appliance in every end use. And this leads to lower electricity assumption in the AAFS scenario 5, because AAFS scenario 5 still has more, or like less efficient appliances available to replace gas equipment, which leads to those appliances adding more electricity for the same amount saved than if it were a higher efficient appliance. So, that leads to AAFS 6 having less electricity than AAFS scenario 5.

So, at the end here, the major updates --

MR. WENDER: Can I ask about that comparison of AAFS 6 and 5, There's also the South Coast AQMD change affiliated with -- or difference between those two scenarios. And I guess I'm curious the extent to which you think the magnitude of the contribution from those two different factors that would be different. And if you could, think about isolating the impact of more efficient technologies from the addition of the South

Coast AQMD regs within there.

MR. COOPER: Yeah. I know for the South Coast AQMD, they're having a start date of 2029. So, it's still pretty close to what CARB's would be, so I don't think that's going to be the biggest factor. I think it is just the technologies that we have available to replace all those gas appliances for AAFS scenario 6.

So, finishing up here, so the major difference I just wanted to point out again at the end is that for this cycle of modeling the Zero-Emission Appliance Standard, compared to what we did in 2022's IEPR update, we are now, instead of including the Zero-Emission Appliance Standard into a single AAFS scenario, which is AAFS scenario 4, is that we applied it into multiple AAFS scenarios, which is 3 through 6.

And then beyond that, another change we had which is going to be probably affecting the electricity values is that instead of what we did last year, which is we had a high efficiency weighting assumption, which basically let us have more priority for higher efficiency appliances to replace gas stock, we're now using that evenly efficiency weighting, so that way everyone's getting an equal share -- or equal share of the total stock being exchanged from gas to electric.

And then, finally, we are now making -- we made changes to our assumptions for the Bay Area AQMD than what we had last year, since the Bay Area last year when we modeled this, for the 2022 IEPR update, still had it that way in 2029. That is when all space and water heaters will have the Zero-Emission Standard. But this year they changed it so that there's two different dates for water heating versus heating.

So, with that, next slide, please. All right, that's the end of the presentation. Thank you all. And my email and my supervisor's email, Nick Janusch, are down here at the bottom of the slide.

And again, if you want to look at any of those appendix slides I talked about on slide two, they can be found after this slide.

VICE CHAIR GUNDA: Thank you, Ethan, really helpful presentation.

Just a couple of quick things. So, on the percentage penetration, is it correct for me to assume that 100 percent of the existing stock, you know, the fuel substitution will accrue in 100 percent of the existing stock for the technologies you mentioned, by 2030.

MR. COOPER: Yeah, so I think what we have in our in -- it's only replacing burned out gas equipment, so it's not like looking any impacts of people replacing their appliances early. But yeah, when we say 100 percent, that means all burned out gas equipment in that year are going to be replaced by electric appliances instead of gas.

VICE CHAIR GUNDA: And what is the percentage of that, of the total stock?

MR. COOPER: I can't remember. I think that we have like a factor that determines when an appliance is going to burn out. So, basically, of our total stock we have, we take a percentage of what we think in that year is going to be available to be -- or, is going to be burning out that year, and that is the gas we actually apply the rates to.

VICE CHAIR GUNDA: I would really encourage us to kind of for us to like track it in a public sphere, the remaining. I think it will be helpful for context. So, that's one element.

The second element, I definitely missed the hourly load modeling, so I don't want Nick to criticize me on this. But, so for specifically the load, right, from these, you are backing in the full load for every hour first, as you do the fuel substitution. And then, to the extent that we realize load flexibility, it comes later as a load modifier in the rate process. Like the load modifier form the demand response and demand flexibility, where do you capture that?

MR. COOPER: I don't think we -- I'm not exactly sure for that one. I think for us, when we ever do our hourly result it's just the hourly impacts of whatever scenario it is. I'm not sure how we -- that plays into demand flexibility or load reliability -- or load flexibility, sorry.

VICE CHAIR GUNDA: And I had to make sure Nick kind of came up then.

MR. FUGATE: So, just to recap from this morning --

(Laughter)

MR. FUGATE: So, what Ethan and his team is providing us, right, is the sort of normal profile for these AAEE and AAFS impacts. Things that we are thinking about in terms of the hourly load model, especially around sort of the development of like analysis that will support stochastic studies, right, is to pay particular -- so, we can take the profiles that we're receiving from the additional achievable modifiers, layer them into our hourly load model process, but they sort of sit there as a static profile, right.

So, we can introduce variations through, you know, bringing in the climate data into our hourly modeling process, but it doesn't sort of capture kind of the incremental variation that would exist around these other load modifiers.

So, that is something that we don't have a fully fleshed out answer for yet, but it is sort of a priority question for us, especially around fuel substitution impacts because they add so much load to the winter months. And we're bringing in this climate data that is showing, you know, a lot of change in temperatures in the winter months, sow e want to be able to make sure that we're, you know, really capturing the full range of uncertainty that we can expect in those periods.

VICE CHAIR GUNDA: Yeah, thanks. I like this panel. It is the one piece of data, like when you get the profiles, the static profiles, right, are the static profiles taking into account I guess the question the ability to load modify, or is it -- so, from the rates or is it coming later, or somewhere else.

Right, so I have a new air conditioning or forced space heating, like let's just do water heating. Water heating, and I'm going to add a new load onto the system that reduces my gas load. The new load on the system, per the hourly profile, how are we -- like where are we starting? And to the extent that there's going to be a rate design, like CalFUSE or others, where do we capture the effects of CalFUSE, for example?

MR. FUGATE: So, I’m not sure that, you know, maybe I’m not quite understanding the question. So, like right now presently the only sort of rate impacts that we have been embedding in the hourly forecast process are from, so the default rollout of time-of-use rates. And so, in that context that sort of comes at the end. We have tried to, you know, sort estimate what impacts, you know, what rate impacts would be. And then, sort of align those, you know, looking at the sort of system load profile from the hourly modeling process align, you know, sort of the greatest impacts with sort of the high load days. So, that’s kind of done at the end of the process. I’m not sure if I’m getting at your question.

VICE CHAIR GUNDA: Yeah, absolutely. So, just kind of making sure, when we think about fuel substitution, right, it is not managed. The load is not managed at the beginning. And then, that is tackled at the time-of-use, or I mean like when we actually think about what load profile you could actually have. So, that’s similar to like what we do in transportation. Yeah, okay, thank you.

MR. WENDER: Actually, I have a kind of parallel question, except of instead of thinking about temporal granularity and response, this one's about spatial granularity within the forecast.

So, understand some of these modifiers or some of the factors in these scenarios are pretty localized. So, you know, Bay Area, South Coast District. When within the forecast process and how do loads within or resulting from those factors get allocated to those specific regions. And I guess thinking kind of, of the use of these scenarios, of the forecast at large in distribution planning where they would want to, you know, know that these loads are coming onto their systems. Is that in later steps or accounted for here?

MR. COOPER: So, when we do our adoption rates and apply those to the different areas, we have to do that by building climate zone, because that's the best granularity that we have in the tool. And our annual and hourly tools go out to IOU territory, I think -- or not IOU. They just go to, I think, planning areas. That's how we're able to -- that's as granular as we can go get for the hourly outputs.

The annual can be by planning area, forecast zone, from like 0 to 20, and then by building climate zone. So, we can go give annual outputs by the building climate zones, and chooses one we think would be inclusive of the Bay Area, Air Resources, or South

Coast. But for hourly, we can only get up to planning area level.

VICE CHAIR GUNDA: And maybe you want to just expand on the next step, so the busbar mapping and how that is allocated, maybe that's helpful.

MR. COOPER: Yeah, so I think with that we do work with the IOUs to try to go find out where any of their busses are, and then we try to go from that, distinguish what would load be for each sector, for like their peak day. And then, determine for each -- well, basically, we take out our planning area hourly results for AAEE and AAFS, and then try to go put those on to each utility, and to go basically to make shares. Sometimes utilities you see, okay, how would the share be for all the entire -- all busses there, how would the shares for each sector be. And then, take those shares of like the load and see like, okay, for PG&E we have X percentage of the load going to this bus, and then X percentage going to the bus, all the way down to all the busses they have for that utility. And then, apply that to the correct planning area that we pull out of our AAEE or AAFS results. That's how we kind of go get the load bus analysis for the three IOUs.

The POUs are a little bit different. They're, I guess, not as -- I guess they're not really created with like load data that's really I think peak data. I think it's more of a proposed load from I think CAISO's TPP process. So, we kind of do that to then to take all of our POU planning areas, and then apply those to the POUs.

VICE CHAIR GUNDA: Yeah, thank you, Ethan. Just I think this is the first time I'm kind of having the pleasure of hearing from you. So, thank you, that's a really good presentation.

MR. COOPER: You're welcome. Thank you.

MR. GEE: Great. Thanks. Now, we can open it up or we have a short session here open for any questions from members of the public or folks on the Zoom call, and the Q&A box. Currently, we don't see any questions in the Q&A box, so I think we can go ahead and continue to move forward here.

Thank you very much Ethan and Ingrid.

We're going to turn a little bit on topics over to the transportation forecast. The baseline transportation forecast is a really popular topic sometimes, and so there's a lot to discuss today.

We have three of our in-house experts here to talk a little bit about some key trends that we're noticing in the market, what's going on with the light-duty forecast, and then the medium- and heavy-duty forecast. And I'll be able to also participate a little bit here and there if there are some questions pertaining to other issues around the forecast.

But first, we will go ahead and get started with Jesse Gage. Jesse is the Lead DMV Analyst in the Advanced Electrification Analysis Branch. Jesse, why don't you take it away.

MR. GAGE: Thank you, Quentin. Good afternoon. I am indeed Jesse Gage with the Transportation Energy Forecasting Unit. I'm here today to discuss the present state of zero emission vehicles as captured by ZEV stats, our dashboard for tracking sales, population, and other ZEV statistics.

I will also discuss some of our forecast inputs as they pertain to hydrogen in particular because, well, we'll talk about hydrogen. Next slide, please.

It is hard to underestimate the importance Tesla Models 3 and Y have had on the ZEV market. Since the Model 3's introduction in mid-2017, and the Model Y in 2020, the two have consistently sold as many as the rest of the ZEV market combined, a trend which has continued to this day despite neither model having seen a significant redesign.

After a strong 2022, in which 346,000 ZEVs were sold, this year sales are estimated to come within a hair's breadth of a cool half million. Next slide, please.

Not surprisingly, the increase in ZEV sales has led to a corresponding increase in their share of the overall light-duty fleet.  As the Chair, the Governor's Office, and others have noted over the past month, we hit a landmark in that one in four light-duty vehicles last quarter were at least partially electric.

I've already mentioned the Teslas, comprising the majority of full electrics.  As for PHEVs, plug-in hybrids, the Jeep Wrangler currently holds the top spot this year, selling more than twice as many as second place, the Toyota RAV 4 Prime.

Overall, fully electrics comprise 85 percent of the ZEV market.  PHEVs take 14 percent, and hydrogen, well, we'll talk -- we'll talk about hydrogen.

Next slide, please.  So, where does this leave us in absolute terms?  California finished 2022 with the ZEV fleet over a million strong.  That's impressive. It's a big milestone.  This year we estimate that we will tack on another 400,000, bringing us to more than a million and a half ZEVs on the road by year's end.

Note that this is currently registered on-the-road vehicle population and not cumulative sales, which I think stands at about 1.6 million as of June, and might hit about 1.8 by year's end.

Next slide, please. Part of the reason ZEVs are taking off in the state is that manufacturers are now, finally, giving consumers what they actually want. And what they want are SUVs, particularly compacts and crossovers, which are red hot right now, regardless of fuel type. If you want to get away from gasoline there are now, by my count, a full 26 compact and crossover SUV models to choose from including BMW's X5 PHEV, Hyundai's, Ionic 5 BEV, and of course the Model Y.

In these two charts we see on the left the sales of ZEVs by market segment, and likewise for the whole fleet on the right. And you can see that after a decade of the ZEV market being tilted toward sedans, likely due to battery constraints, as of 2022 the mix of cars and SUVs was just about equal in the ZEV and non-ZEV worlds, although ZEV pickups still do have a bit of catching up to do.

This concludes my look at the current state of the BEV and the ZEV markets, with assistance, as always, from Elizabeth Pham who runs the dashboard itself, and the DMV Vehicle Registration database which is the ultimate source of this data.

Now, as promised, we can discuss the state of hydrogen. And at the present moment you've probably guessed that, yeah, it's not great.

Next slide, please. At the August 9th business meeting it was reported that Shell had planned on backing out of an agreement to build numerous hydrogen refueling stations in California.

Vice Chair Gunda responded by asking, rhetorically, how this would impact the inputs to our hydrogen forecasts, time to station, refueling time, and so forth.

I've mentioned in other workshops that I lease a Hyundai NEXO. You can see the side of it on this slide, here. I'm two years into my lease and I can say I still love the car. I love the quiet ride that comes with not having an engine. It starts up right away. No oil to change. Really, no maintenance at all, really, except for the tires. And it's fun to drive. I mean I love taking it up to Placerville. I've taken it down to Monterey a couple of times. You name it. I wish the dog would keep it cleaner, but that's my own cross to bear.

But the first thing anyone ever says to me when they see the words printed on here is, without fail, where do you fill it up? On a good day, I can say that there's a station two miles away from me, so I just stop by on the way home from grocery shopping, easy-peasy.

But the past two weeks in particular have not been good days. And it's made this question increasingly uncomfortable to answer.

And so, I want to give you a personal account, a response to this question and how it impacts me, and other fuel cell vehicle drivers, with an eye, of course, towards inputs to our forecast.

Next slide, please. I figured I'd start with what gasoline users may think is the most important aspect of hydrogen but for lessors, like myself, and new buyers it's actually the least important for now, at any rate.

About a week after I signed the lease, I took it in for its first fill up at the Shell Station on Fair Oaks Boulevard. You can see on the left side, the top left there that the posted price of hydrogen at the time was $16.45 per kilogram. That price stuck for well over a year. Not just at the Fair Oaks station, but at every station I've seen in Sacramento, and the Bay Area.

Last October, however, Iwatani, who runs the West Sacramento station, posted a note to SOSS, the station-tracking web app set up by the Hydrogen Fuel Cell Partnership. It warned that the price per kilogram would increasing to $24.99 due to a downturn in the LCFS credit market. Shell Hydrogen followed suit in January.

The photo on the right shows my most recent fill up on July 30th, also at Fair Oaks. By this time the price had risen to nearly $30 per kilogram, almost double what it was two years prior.

Now, neither $16.45, nor $29.95, that's not what I pay. That's not what new FCEV owners would pay. In reality, we pay nothing. You see, when you sign off on the purchase of a lease of a new Mirai or NEXO, you are issued… let me cover up the numbers - this card. It serves to provide complimentary hydrogen for three years, the life of a lease, or $15,000, whichever comes first.

Now, my NEXO gets about 60 miles per kilogram. And if you do the math, at $16.45 per kilogram, $15,000 will get you some 55,000 miles, or more than 18,000 miles per year. And that's a lot. I mean unless you're driving it for Uber or something, that's easily enough for just about any purpose.

And for me, I mean it turns the posted price into basically kind of a bit of trivia.

But at $29.95 per kilogram, now that's only 10,000 miles per year. And that means depending on driving habits, and what happens with LCFS credits, a lessor today could be in for an especially rude surprise toward the tail end of the lease.

Before I go on, I do want to apologize for the dark -- I know the dark photo in there is kind of dark. I wanted to go back and get a better picture. I couldn't, unfortunately, because -- well, next slide, please -- the station is down. Along with Citrus Heights, and three other Northern California hydrogen stations, indefinitely.

Per this email, sent to my personal inbox last week, during that business meeting oddly enough. Indeed the only Shell station now operating is their most recent one in San Jose.

Now, this is frustrating. But even before this outage both Sacramento stations have had extended downtimes in the past year. Fair Oaks was down from last August until about March, and even then was touch and go until mid-May. Citrus Heights shut down last December through June, and didn't have its legs under it until just a couple weeks ago.

This leaves West Sacramento as the only operating station in the area, except they shut down yesterday due to supply. They're not coming back until tomorrow.

That means if I had to fill up tonight, the closest place is Concord, a three-hour roundtrip, even without rush hour.

Not to be outdone, True Zero had to shut down ten of its Southern California stations this week due to a major supply disruption. Thankfully, four of their stations have since come back on, on an emergency basis. But those emergency measures have pushed the price up to a full $34.84.

These intermittent, seemly random closures, have had three knock-on effects. First, as this slide says, it takes longer to get to a station that actually works.

Second is an indirect impact on the effect of vehicle range, because while I can get 380 miles on a good fill up, I now have to mentally budget an emergency reserve in case I’m forced to drive to the Bay Area just to refill.

Third, these closures put pressure on nearby stations, which leads to, next slide please, some absolutely jaw-dropping lines at those stations that do remain open.

You can see here on the right a driver report stating that at 10:00 p.m. Tuesday, the West Sacramento station had 22 cars waiting to fill up. Now, that’s bad. But just as scary is the warning on the left. You have to wait ten minutes between filling at this station, and there is only one pump that has ever worked as far as I know.

So, given that it takes five minutes to fill, several more minutes for the driver to leave, and the next driver to handle the point of sale ritual, in reality this station can only service four, maybe five cars in an hour.

Now, I will admit, I'm being a little hard on poor West Sac here. I understand they were the first retail station to open in the state, so lessons learned building this one have hopefully carried over to other stations. I haven't seen that 10-minute wait in any other ones. One of them had a five. But this one is the only one that said ten.

And I'll caveat, I'm not really sure I buy 22 cars in line here. I mean there's a lot of room at that station, but not that much. And reports are user submitted, so I kind of wonder if somebody was just venting their frustration here.

That said, I will note that I did find myself 13th in line last December, and I clocked that wait in at four hours even.

Next slide, please. So, I've discussed how the LCFS market has impacted the price of hydrogen. And I've also given a personal account of how a supply crunch, such as today's, impacts my personal driving time to a station, refueling time, and indirectly vehicle range.

So, the question now is where does this leave us in terms of the forecast? Nowhere good, that's for sure. But I am aware that this workshop comes at a particularly unfortunate time in hydrogen's journey, with outages coming from multiple fronts.

I also know that anecdotes, by themselves, are not data. And those of us in Sacramento are harder hit than most during shortages, because we're a bit of an island on the station map. There's only three stations here. And only 5 percent of FCEVs are located in the area.

But I'll note that this is the third major disruption I have experienced in two years. And during each of the last two, I eventually ended up having to take the drive of shame to Concord, and I suspect I'll be doing it again tonight or tomorrow, depending on how West Sac is doing.

I've also seen station maps this week, with every station north of San Jose out. Everything from LAX to Disneyland out. So, I know disruptions on a regional scale are still possible statewide.

As Vice Chair Gunda suggested last week, I look forward to talking with our good colleagues in FTD about the impact Shell's decision will make. How upcoming grants from us or the Department of Energy can mitigate the damage. And any insight regarding the current crisis which, hopefully, will recede by the time the forecast is out the door.

The present state of hydrogen may not be great, but I don't think its future is unsalvageable. And I look forward to more good days in the future.

And that's all I've got. On behalf of nearly 12,000 Californians who have adopted fuel cell vehicles, I'd like to thank you for your time. Commissioners, please forgive me. And I'll take your questions at this time.

MR. GEE: Great. Thanks Jesse. Actually, I think what we'll do is we'll get all the -- unless, are there some -- okay, yeah, we'll take all the transportation folks and then we'll have, I think, a really healthy back and forth amongst lots of different topics.

So, the next up is Aniss Bahreinian, PhD. She is the Lead Transportation Forecaster in the Advanced Electrification Analysis Branch, here to talk today about the light-duty forecast inputs assumptions and scenarios. Annis.

MS. BAHREINIAN: Good afternoon Commissioners and stakeholders. I'm here today to talk about the light-duty vehicles, the vehicle forecast. And, specifically talking about the inputs and assumptions, because we don't have a forecast, obviously, right now. And so, we are going to talk about the inputs, and assumptions, and the trends that we see in the market.

Next, please. What I would like to do is first talk about the forecast and scenarios in general. And there are two types of future paths that we see for light-duty vehicles.

First one is what we refer to as a forecast, or more precisely baseline demand forecast. And it is based on all of the baseline input forecasts.

What are these input forecasts? We use economic and demographic variables. We have vehicle attributes that we use in generating a forecast. We have fuel price forecast that we use for our forecast. And we have incentives, government incentives that we use.

And we separate the impact of incentives from the vehicle prices because we believe that consumers respond differently to an incentive versus price, versus some of the other forecasts that just simply reduce the amount of price by the amount of incentive.

To be sure, and to be more precise we have separate impacts from these two variables.

The second future path that we have is what we refer to as AATE scenario. AATE stands for additional achievable transportation electrification. For this AATE scenario, the fleet population is exactly the same as the baseline forecast. So, the two lines are going to be one in the same. It uses the baseline forecast for total fleet population.

However, when it comes to the fleet composition, which is the class and fuel type composition of the fleet, what AAET scenario does, it assumes that the market shares that have been projected by CARB, by Air Resources Board through their ACC2 program, which is Advanced Clean Car 2 program, is exactly the same as the market share that we have for ZEV in our forecast.

So, that is essentially the difference between the AATE scenario and the baseline forecast. It makes the assumption that ACC2 market shares apply to our forecast for ZEV.

Both forecast and scenarios assume the same vehicle miles traveled. And that's important. From the beginning, one thing that we have done is we are assuming that all of the fuel types, regardless of the fuel types, all of the vehicles are going to have the same VMT per vehicle.

Why do we do that? Essentially, because our forecast is a long-term forecast and in the long-term

ZEVs cannot really stay in the market if they cannot drive the same number of miles. And we have overlooked some of the initial low VMT that we have seen for EVs, and we have been assuming that they are driving the same number of miles as all the other vehicles.

Vehicle population, fuel economy, and VMT determine the transportation fuel demand. So, all of those are important for our energy demand forecast. And including transportation electricity.

Next, please. What are the key inputs for the baseline light-duty vehicle forecast? Well, if we divide it into two components, our forecast is generating a forecast of LDV population, as well as the LDV fleet composition, which is both class and fuel type.

For the LDV population, the key drivers are household population and income. Those two are the ones that determine how many vehicles we are going to have in the state in 2030, or in 2040, or 2050.

For residential light-duty vehicles, the macro economic variable that we use in the forecast is personal income. That's what we use. And what personal income means is that we're going to include all of the incomes that are received. And the incomes that are received includes all the incentives or all the assistance that all of us were given during the COVID time. So, the personal income actually in those times has gone up because of those assistance, and those are the numbers that we're including because you can use that money, for instance, to buy a vehicle. And that's why we use personal income.

When it comes to commercial light-duty vehicles, what is driving the population of the commercial light-duty vehicles is the gross state product, or GSP. That's what we use for commercial vehicles.

When it comes to light-duty fleet composition, which we also forecast, it's part of our forecast, we are using vehicle attributes. And the vehicle attributes include the vehicle price, MPG, range, cost per mile, and acceleration, and other factors that we are including.

In addition to that, we are also including incentive. But more specifically, we are only including state and federal incentives. So, we are not including the local incentives. That is a shortfall of our forecast.

Next, please. Now, we have about -- we generate the forecast of light-duty vehicle for the residential sector for about 500 different household types. Where do we get these 500 household types? Well, when you're including different income categories, different household sizes, different vehicle ownership, and different number of workers in the family you're going to end up with about 500 different household types, which is what we are forecasting for.

Now, all of this data, for all of this data we are using American Community Survey. That's the only place where we can find this data. Department of Finance cannot provide us with that information and neither do any other sources. So, we are using American Community Survey to identify all of the households that are in different household types that we have in our forecast, and we are accounting for the exact number of those in the base years.

So, we use ACS for the base year and we are dividing all of the households in different categories.

Now, one of these is, well, how many households have how many cars? And that is our graph here, which is the number of vehicles in households and that, too, is coming from 2021 ACS, American Community Survey.

We can see here, for instance, and this is important, you can see that almost 7 percent of households have no car. So, if you're talking about the ZEV vehicles, we need to keep in mind that 7 percent of the households have no cars. And in the next graph you're going to see the relationship between that and income.

The most dominant category is the two-car households. They are the biggest portion of the households in California. And it is followed by the one-car households. And, of course, those households that have three or more vehicles are only 26 percent of the California households.

This is important for us because over time we have noticed that those who are buying ZEV vehicles are the ones that have more than one car. So, that becomes important for us. And, therefore, we are going to have to separate households based on the number of vehicles that they own. It is different, their preferences for ZEV are different depending on whether they have one vehicle, two vehicles, or three vehicles.

Next slide, please. All right, this I have -- we have used the income categories that we are using in our model. This is important. So, please do not derive any conclusions about income distribution in California based on the graph at the bottom.

If you look at the graph at the bottom, we have the first two income categories that we have, they have a $10,000 interval.

The next ones that you see over there, until they reach the income of $100,000, the income interval for those is only $20,000. Between $100,000 and $250,000 the income intervals are $50,000.

So, I'm just alerting you, do not derive any conclusion about income distribution for the State of California based on this graph. The only reason why we have those categories is that our model is using those categories.

Why do we even use income in our model? The reason is that consumers have higher price sensitivity at the lower income brackets. A thousand dollars means a lot more to somebody who is making only $10,000 a year compared to somebody who is making $250,000.

And so, we are going to have to include income so that we get the right price elasticity, the right price response by different income groups. If California population grows poorer over time, what that means is that they are not going to be as able to purchase vehicles, new vehicles in the future. So, that is going to matter to us and that's why we are including the income categories.

If you look at the graph on the top, what you can see is the number of vehicles that each household has in each income category. As you can clearly see, the first two income categories, which are the lowest income categories, you would see the larger share of the no-vehicle household. Not only that, when it comes to buying vehicles, those households that are at the bottom of the list when it comes to income distribution, they usually buy used vehicles, not new vehicles. That is significant for the sales of ZEVs, because ZEVs are mostly new, have been mostly new vehicles. And, therefore, the worse is this income distribution, the worse it's going to get for the ZEV sales.

However, now, over time, over the last decade we have also generated a number of used ZEVs. And so, those households can purchase the used ZEVs. But in the beginning we didn't have any. And so, the only ones that would really qualify are the households that are at the higher end of the income distribution.

So, this one, you could see that the reverse is true for the three-plus vehicle households. You can see that at the higher income categories, the lowest -- if you focus on the zero-vehicle households, the lowest numbers are in the $250,000 income category. So, the relationship between the number of vehicles and income reversed at the top end of the income distribution.

Next, please. All right, so we talked about the household population in California and this graph shows household population from 2020 through 2040.

We have seen, for instance, all the news about migration of -- domestic  out migration of population from the State of California.  And in the graph that -- in the historical data graph that Nick Fugate showed on August 15, I think, in that graph you could clearly see that there's a decline in population.  So, it shows that out migration.

This graph, however, this is the number of households that we have in the State of California. This graph doesn't really clearly show that decline.  It shows, instead, that between 2023 and 2040 we have 1.4 million additional households.  So, the number of households is growing.

As Nick explained on August 15, the way we have derived this is that he has -- we have used the population forecast that was developed by Department of Finance in July, I believe, so it was very recent.  They don't have a household population forecast, yet.  So, what has happened is that we have taken the household size forecast from the 2022 IEPR and applied that to the population forecast in 2023.  So, you don't see some of those bumps here.

But over time what you can see clearly is that household population is growing in California, and it grows by 1.4 million between 2023 and 2040.

Yes?

VICE CHAIR GUNDA: Aniss, just on this one, thank you for raising that question. I was kind of thinking it. So, like the previous slide, which kind of shows the ownership, you know, this is kind of the household distribution, you know.

MS. BAHREINIAN: Uh-hum.

VICE CHAIR GUNDA: So, as you move forward, as the households grow, I understand the assumption right now we are leaving the number in the household the same. Do we have the ability to understand, you know, as you have more houses, you know, potentially lower number of households in the future as the out migration happens, what that effect would be for the new vehicles sold in California?

MS. BAHREINIAN: We can -- we can definitely, if we have more insight into how exactly that is going to happen, we can make adjustments.

But as of now what we are doing, we are taking the 2021 ACS and we are just applying the household population growth to those categories that we already have.

So, what we have is for 2021 we have the actual numbers. Those are the exact distribution of households in the State of California. But when it gets to the forecast all we have to do, or all we can do because nobody really has the detailed data that we need, is apply the growth in population, household population to our 2021 base year that we have. That's how we use it.

VICE CHAIR GUNDA: Right.

MS. BAHREINIAN: So, we are kind of applying the same rate to all of the households.

VICE CHAIR GUNDA: Yeah, just kind of maybe we can keep going with the presentation, but I'll just have a couple more questions on that.

MS. BAHREINIAN: Sure.

VICE CHAIR GUNDA: So, presumably, I mean there is a correlation between the actual demographic, like age distribution of Californians and, you know, how many vehicles we buy, and how does that compute into our overall modeling.

And the other one, on the VMT, you know, we said we're going to hold the VMT consistent given that CARB's kind of pushing, you know, through the scoping plan and others, you know, the deduction in VMT.

How do we -- you know, how are we thinking about continuing to put those in different variables into our modeling and to what extent, you know, those have huge differences and what time frame, right. So, I think for me, I'm kind of thinking through, completely recognizing that we have great impacts on consumers and we don't want to, you know, over procure. But at the end of the day, you know, we want to have the ability to project the uncertainties and be able to guard, you know, enough cushion for resource procurement, right.

So, I'm thinking through that and pretty much all my questions, given the last couple of years, has been like how do we keep the system reliable and how far in advance do we bake in these electrification uncertainties, and how, so we can really kind of guard the system from reliability issues.

So, just want to pin those questions as you continue your presentation, and if you have an organic moment just drop in.

MS. BAHREINIAN: Sure. One thing that I can directly respond is that we do not account for age. And we all know that age matters to the number of vehicles that people hold. But, hopefully, when we are looking at the income categories, and the age kind of falls into that. Some of those lower incomes are the older, more senior population. Some are on the other hand, right, they are in the 250 plus income category.

But we do not specifically address age. And the reason for it is that remember I said we have 500 different household types? If we incorporate age into that, it's going to go over 1,000, 2,000, 3,000 different household types. Because we also, I personally have been interested for instance on how women buy differently when it comes to the vehicles, compared to men. But we can't incorporate all of these factors that could actually play a role in.

So, it is just our computational capacity doesn't take us there. Otherwise, you're absolutely right.

VICE CHAIR GUNDA: Yeah, I think on that one you know, know that we have, if I remember it right, Southern California Edison's model is more like a diffusion model versus our model.

MS. BAHREINIAN: Uh-hum, yes.

VICE CHAIR GUNDA: Are there opportunities for just kind of comparing the differences and how big the different could be, totally understand that, you know, in some sense you are -- I mean it's about where do you want to use your computational might. And, you know, depending on the different models having just kind of that background on the potential uncertainty in the forecasting.

At the end, if we are going to look back at the scoping plan and we're going to say we're just going to use the AATE for planning, I think that safeguard us largely.

But just wanted to kind of continue to put it in the public discourse, you know, what are those doubts and what are the uncertainties as we move forward. Thank you.

MS. BAHREINIAN: Yeah. As you recall, Commissioner, in 2017, since 2017 actually, one of the things that we did was we developed five different scenarios for light-duty vehicles. And those different scenarios that we had for light-duty vehicles for the forecast, they were reflecting the uncertainties in the economic conditions, as well as technology conditions.

But since last year, we are only generating one baseline forecast and then plus the AATE scenario. If there is interest in generating more forecasts, we would be happy to do so in future years. And we will also be happy to make comparison with Southern California Edison and compare the forecast, and see where they are and where we are. Absolutely. That would be a great idea, thank you.

MR. GEE: Vice Chair, just a real quick response to something you pointed out. You mentioned the CARB VMT reduction cases, or reduction goals under the AB 32 scoping plan, under the 2022 AB 32 scoping plan.

We are in the process of developing new travel models that will allow sensitivity for VMT. I think what we'd be talking about overall is sort of a net reduction in VMT. So, maybe fewer people are driving overall. I do think that maybe we would have an AATE scenario, we could have an AATE scenario that does something where the VMT itself is the variable that changes.

But generally speaking, we want the VMT to be consistent across the scenarios so that we're evaluating the electrification, the impact of electrification. But definitely something that we want to consider in the future. And I think these new travel models that are in development, looking forward to presenting those to you and to the Commission later.

MR. GEE: Aniss, was there anything -- oh, okay. Yeah.

MR. WENDER: Maybe I'll ask, then, about these new travel models that are upcoming and to be included. Will they have other modes of mobility, small distance travel, and a better breakdown of the types of trips that drivers, customers, residents take?

MR. GEE: Yeah, there's a lot. I think Aniss might be able to speak to some of that. I mean I know that she's interested in the autonomous vehicles. We are talking about micro mobility, other sorts of options. Yeah, so definitely a lot of different ways for us to think about the changing world of travel. Our models, travel models up to now are a little bit more static, yeah.

VICE CHAIR GUNDA: Okay, I was going to hold back, but I want to just state this, too. I think, Aniss, like going back two or three years, you know, especially the forecasting team was under a lot of pressure to adequately capture the electrification, right.

MS. BAHREINIAN: Uh-hum.

VICE CHAIR GUNDA: And kind of like say, let's say kind of look at the higher levels of consumption, so we can plan the grid.

I think now another wrench has been thrown at the team, which is you want to do that, but you want to be able to estimate the gasoline consumption appropriately for the SBX 12 work, you know. So, I think you're now kind of stretching -- you know, the way I always think of it is like, you know, you're turning a corner and the lanes have to be the widest. You know, and then we'll kind of -- once we hit kind of our next quasi-equilibrium I think we'll be looking for efficiencies.

But I would really recommend thinking about our forecasting as more of a, you know, bookending the worst case scenarios on all ends, right, so that we can really plan for those things.

Again, I understand that we want to be reasonable to occur and we want to be thinking through, you know, the rate impacts, and other impacts that could potentially come from the forecasting. But to the extent that we have flexibility, I would generally recommend being on the outer edge of planning these things as we go through the transition. Thanks.

MS. BAHREINIAN: Thank you. One thing that I can add, when you're asking about mode, transportation mode, for the new travel demand model we have -- one of the additions is autonomous vehicles. And as you know, we are planning a new survey, which was just approved by DGS yesterday. And as part of this new survey we are incorporating autonomous vehicles on a personal level, not just at the TNC, but on personal ownership level. We are going to incorporate that into our light-duty vehicle demand forecast, hopefully.

And in addition -- and that comes on our part, under light-duty vehicle choice model. But then, when it comes to the travel demand model, so we are foreseeing that autonomous vehicles are going to get into our LDV demand forecast, which is used by travel demand models. And, therefore, the travel demand models are also going to incorporate a separate set of VMTs for autonomous vehicles.

In addition to that, we are also identifying a separate mode for TNCs, so that one is also incorporated into the new travel demand model.

But in response to Commissioner Gunda's comments regarding CARB's VMT reduction plan, one of the features of the new models is that the new travel demand models are pretty much following the CARB's EMFAC model. So, to the extent that CARB is going to reflect that in their model, it's also going to be reflected in ours. So, regarding your comment on how we're going to deal with that, that's going to come next year. But for this year, we are going to continue to use the existing travel demand models that we have.

Next, please. All right, and how about personal income. Personal income, as you can see with the -- I said that personal income includes -- first of all, this is aggregate personal income, not per household. And you can see the numbers are in trillions.

VICE CHAIR GUNDA: Yeah, it was not being reflective of my income. I was like what is going on.

(Laughter)

MS. BAHREINIAN: What you can see here is that there has been a decline between 2021 and 2022. And it goes back to all those assistance that was given during the COVID. When they dry out, their personal income is also going to go down.

But between 2023 and 2040, as you can see aggregate personal income in California is also growing by $1.4 trillion. This is, of course, Moody's forecast and that is what we are going to use. So, all those households, with all the incomes that they have we are also growing our household income by the percentage growth that we could see in the macroeconomic forecast.

Next, please. All right, so here we come with the vehicle attributes and we are going into the fleet composition. To the fleet composition, -- it is the vehicle attributes and the incentives that matter.

So, the household population determines total vehicle population, but vehicle attributes determine, or are the key drivers of the fleet composition, particularly by fuel and class size.

Attributes include -- what are these attributes? We keep talking about vehicle attributes, what are they? They are price, fuel economy, acceleration, etc. We always leave some of them out. It is range, for instance, that has been left out here, maintenance costs and the fuel cost per mile.

So, fuel price directly doesn't enter into the vehicle choice model, but it does enter through cost per mile, which is a combination of MPG, or the fuel economy, and fuel price forecast that we have.

While all of the attributes have significant impact on -- when we are running these models they are significant and they have impact on the vehicle choice. But the one that has been the primary factor for as long as I remember is the vehicle price. That is important.

It is for that reason that we are going to look at some of the price trends that we see in the light-duty vehicle market.

And what we should also note is that I mentioned before that our forecast only accounts for state and federal incentives. So, IRA incentives are in, the rebates are in, clean fuel rewards are in. All of these are state and federal. But we do not incorporate, we do not account for the impacts of local incentives. And that is also an important fact to know and declare here

Next, please. All right, so a look at the class distribution is going to shed some light on where things should be going. If you go -- if you recall from Jesse's slide number 4, you could see in that slide clearly that California has been moving away from cars and into the what we call truck, which is everything but cars. You can see the first five categories here are cars, compact car, large car, midsize car, sports car, subcompact. But we are moving away from that and the share of the trucks, everything else is considered trucks, the share of the trucks in California vehicle population has been growing. And when it comes to the sale of these vehicles, the share of trucks has been increasing over time, over the past few years, as we know.

So, that's important. It's important because if a manufacturer wants to sell vehicles, they have to consider that more and more people are buying from those categories, from the truck categories, and more importantly from SUVs. This is important for the OEM because they would decide where their investment should be going. As you know, GM and Ford for instance, last year -- not last year, in the -- I think two years ago or so, they just moved all of their car productions outside the U.S., with the exception of one or two car models.

But then, they were focusing -- they are focusing their U.S. manufacturing on truck categories. And more importantly, they are growing their SUV population. Why? You can see here clearly the why is really shown here both in the premium and in the standard vehicle classes it is the SUVs that are selling more. And more distinctly, it is the compact SUV that has the highest share of the market, both in the premium market and in the standard vehicle market.

What is the next one that comes? So, number one is compact SUV. What is number two? It is the mid-size SUV. And then, it goes to midsize car, which is the next one with highest sale here.

So, there was a time when we were selling a lot of subcompact and compact cars in the State of California, but not anymore. Now, the majority goes towards SUV. And that is important whether you are a ZEV manufacturer, or not, it is important to you because that's where the investment funds are going to go to.

Next, please. These are based on the actual market data. Now, this one shows MSRP. We had to increase the font size, otherwise they should all be on the same slide. But what you can see between this slide and the next one is that the MSRP for the gasoline vehicles, and we are just comparing the two largest categories, which is gasoline and ZEV, the MSRP for the gasoline vehicles overall have been increasing. Between 2019 and 2023 we can see that.

But when it comes to battery electric vehicles, with the exception of one or two classes you could see that the price has been on the decline, and that's obviously good news for everybody. So, while gasoline vehicle prices have been rising, ZEV vehicle prices have been declining.

And you can see on the column at the end, at the very end, you could see that we don't have BEVs as of 2022, even 2023, we don't have BEVs in every class of vehicles. But the column at the end is showing in our forecast when those vehicles are going to be introduced in the market.

For instance, large cars, EVs, are going to enter the market in 2026. That's our forecast, that's what we think.

On the other hand, when it comes to compact pickup, we see that coming to the market in 2025. And heavy pickup is going to come in 2026.

This is important, this trend is important and because of this trend and what we are doing in our forecast, we are lowering the price of EVs over time. Not by too much, but we are lowering the prices of EVs over time. And, obviously, that is going to encourage more purchases by consumers in our model, in our forecast.

Next, please. All right. And so, in this one you could see that large SUVs are coming to the market next year, and midsize SUVs are going to come to the market, in EVs, in 2024. And minivans, which is -- I think it is, and Jesse can correct me, I believe the minivan that we are going to bring to the market in our forecast is Volkswagen ID Buzz, I think. Yes.

And, of course, then we also have the standard van that is in our forecast, it is going to come to the market in 2025.

So, by 2026, essentially, we are forecasting that we will have EV production in every class of vehicle. By 2026 we will have EV production and supply in every class of vehicle, so we are covered, and they can compete then with gasoline vehicles.

As long as we don’t have any EVs in a class, obviously people are going to buy gasoline. Those who need those classes, they are going to continue to buy gasoline and diesel vehicles. But once we are introducing these vehicles into the market, then they are going to substitute for gasoline and diesel vehicles, as they should.

Next, please. Okay, thank you. How about miles per gallon? Well, miles per gallon, or the fuel economy is important for vehicle choice. When you’re buying a vehicle, you are thinking about, well, what is the fuel economy of this vehicle. And people have the tendency, because they want to save money, they have the tendency to go to the vehicles that are more efficient. Of course, this is after taking into consideration whether it meets their family's needs, or if they need trucks, or SUV. Between those SUVs that are in the market in those classes, then they are gong to pick the ones that have higher fuel economy or they are hybrid, for instance.

In this one, we are just comparing the standard vehicles, so this is not the premium, only the standard vehicles. We are comparing the MPGs of BEVs and gasoline vehicles. This is important. So, MPG is both important to the choice of the vehicle, but because we are generating fuel demand forecast, MPGs are important to our fuel demand forecast.

So, look at the column on the right, which is for the BEVs, the highest place goes to midsize class at 130 miles per gasoline gallon equivalent. That's a very high fuel economy. And the only class in that category for EVs is Model 3. So, Model 3 actually have an MPG of 130.

And so, what this means is that moving forward, let's say, let's just assume that everybody was holding a Model 3, that is going to reduce electricity consumption. So, that is important for us to notice, to pay attention in the differences in the fuel economy. We are not only becoming more efficient, but the consumption per vehicle is actually going to go down with the gains in fuel economy. We don't know how much longer this is going to grow, the fuel economy is going to improve, but we are making the assumptions we are using in order to be consistent with CARB. CARB is using a 1 percent growth in fuel economy over time, and that's what we are using.

So, whatever you see here is going to grow 1 percent a year to 2040. And as such, that is going to put a downward pressure on consumption per vehicle.

So, that is going to have implications for our transportation electricity demand forecast.

We have other -- as we have mentioned repeatedly, we have other attributes, for instance range. And I think Ben was asking this morning whether or not temperature, high temperature is going to impact range. Yes, it does. From what I have read, it is reducing range by 30 percent.

So, what does that mean? Well, for those people who are -- who are charging their vehicles at home, well, they're going to just more frequently charge their vehicle. They're going to fill it up and they're going to bring it back. I think that the implication would be mostly for the public chargers. And I don't know if our colleagues at Fuels and Transportation Division are going to account for that or not. But this is a new thing, so we haven't really incorporated it, yet. We haven't thought deeply about it, how we could incorporate it into our load. But that is going to -- it's going to have impact on the number of chargers and when people are charging. The other --

VICE CHAIR GUNDA: Aniss?

MS. BAHREINIAN: Yes.

VICE CHAIR GUNDA: Just one, one quick question. So, when we have the total vehicle population in California, so we have the sales in California and then sales outside of California that might be coming in, right?

MS. BAHREINIAN: Yes, uh-hum.

VICE CHAIR GUNDA: So, just want to understand the rule right now of the ICE ban in 2035. Does that mean -- is the interpretation that no more, you know, ICE vehicles are sold in California or just in California -- what's the interpretation? I mean could it be conceivable that we're in a situation where people are just buying across the border and bringing it into California?

MS. BAHREINIAN: I think Quentin knows more about that, but I don't think that they are going to let it go that easily.

VICE CHAIR GUNDA: I know. I mean if it's a two-part question, then the second one is like the policy safeguard from some of those.

But just what is the interpretation right now? And I'm kind of just thinking about this NEM 2.0 and then you saw that surge of interconnection requests for, you know, previous NEM. I mean are we going to be in a situation like that where you see a surge towards the -- before 2035? And second, do we continue to see vehicles coming across the border into California?

MR. GEE: Yeah, I mean -- yeah, so the -- as I have read the regulation, it doesn't say anything about cars that are -- you know, you buy a car, somehow you register it in Nevada first, and then -- or, let's say you go over to Reno and you have a cousin who has an address there, maybe you can try to do that and then play switcheroo back in. I don't know the specifics on how there would be enforcement of that. There may be limitations on the model year that you can register. I'm not sure what the intentions are there, yeah, there is theoretically that potential risk there.

But, you know, we're kind of not really seeing that right now as a likely option. But, you know, yeah, there’s always some possible reason why it could actually happen.

Probably, there’s -- and the other question, kind of like getting up to what’s going to happen in 2034, is there going to be a mad rush, like you mentioned with NEM 2.0?

I mean that -- we could also see that. But, you know, there’s also -- that’s kind of like you want to get locked into something good, like a good deal. In 2034, I don’t know if people are going to always be thinking this is a great time to buy this kind of thing, and you better get it now because, you know, you’re -- I mean possibly. I mean some people might have that interpretation. But, you know, there have been other times where actually you see markets decelerate or rapidly accelerate because people don’t want to be left behind in the transition to something new.

So, I think there’s uncertainty there, but something we’re going to pay close attention to.

VICE CHAIR GUNDA: Okay, you actually like stated that I’m like it could go both ways, right, and then your uncertainty just grows.

MR. GEE: Yeah.

VICE CHAIR GUNDA: Right, both from the vehicle population and the ZEV penetration. So, I think it will be good for us to just qualitative set the stage for the discussion.

MR. GEE: Yeah.

VICE CHAIR GUNDA: As we move forward.

MR. GEE: Okay. Yeah, great. Yeah, that's something I think will make it into the IEPR, yeah.

MS. BAHREINIAN: I think it is also, at least in the conversation of some of the CARB staff, there is that expectation at CARB that in 2034 there could be a mad rush toward ICE vehicles. Because that would be the last year when they could purchase it.

How significant is that going to be? We don't know that. But I'm sure that the people who love ICE, they are going to make sure they are going to buy an ICE vehicle in that year.

MR. GAGE: I think we sort of saw the same thing when incandescent light bulbs were phased out, people made a mad rush.

MR. GEE: There are going to be some challenges, I think also in the market on that front. As Aniss pointed out, prices are going up in the ICE realm. Prices are coming down in the battery electric realm.

It looks like price parity for most vehicles, battery electric versus the internal combustion equivalent type of vehicle. Some of the market analyst work that we've seen is saying 2024, 2025 for larger vehicles that tend to be a little more expensive, maybe that will happen.

But then, 2028 or so, or maybe a little bit later for even smaller vehicles. There are fewer moving parts in electric vehicles, they're easier to manufacture. And, you know, do we expect ICEs or gasoline cars to continue to increase in price? Maybe, maybe not. But we have heard some reports about the supply chains for ICEs maybe becoming less streamlined and sophisticated as the OEMs here, the automakers, start to transition themselves. So, what was a well-oiled machine may not be so well oiled.

So, yeah, there's a lot of -- I mean there's lots of reasons why it could go in either direction.

VICE CHAIR GUNDA: Yeah, thanks Quentin. So, I think, you know, just from CEC's perspective, right, so we have this important planning and forecasting function, but we also have the opportunity to be that, you know, independent, you know, venue for having this kind of dialogue to really set the stage for --

MR. GEE: Yeah.

VICE CHAIR GUNDA: -- you know, both what other constraints or policy, you know, levers we have to push to make something happen, right. And also, at the same time like looking at the uncertainty of that happening. So, I really appreciate you looking into that and setting the stage.

MR. GEE: Right, thanks.

VICE CHAIR GUNDA: Thanks.

MR. GEE: Uh-hum.

MS. BAHREINIAN: Next. Next, please. All right, thank you very much for your attention, and we will be happy to answer any question that comes up. And I should mention that my colleague, Jesse Gage, sitting right next to me, is part of the light-duty vehicle forecasting team, has been doing a lot of heavy lifting.

We have a new colleague, Namita Saxena, who is also working with us, and she dives right into it.

And, of course, Elizabeth Phan, who is also working on attributes. So, this is the light-duty vehicle demand forecasting team. And we thank you all for listening to us.

MR. WENDER: Thanks.

MR. GEE: Thanks, Aniss.

I’ll hand over to Maggie Deng. Maggie is the Lead Medium- and Heavy-duty Forecaster in the Advanced Electrification Analysis Branch.

Maggie.

MS. DENG: Thanks Quentin. Can you all hear me? It sounds like it’s working.

Okay, great. Good afternoon everyone. My name is Maggie Deng. And as Quentin mentioned, I am our Lead Forecaster for medium- and heavy-duty vehicles, especially our Freight and Truck Choice Model.

Seeing as I’m the last presenter for today’s Friday workshop, I will try to keep my presentation succinct.

Next slide, please. So, in my presentation I’ll be providing a high level summary of MDHD vehicle classes that our demand forecast covers, key model components, some of the key, important data sources, as well as a high level overview of key incentives. And also, giving you just a sample snapshot of our truck price forecast.

Also, on the right side here I’ve included a graphic explainer of vehicle weight classes from our very own MDHD Zero Emission Vehicle dashboard, created by my colleagues in our unit, and which I highly recommend everyone to check out on the CEC website, if you haven’t already.

And as you can see here, our modeling considers weight classes 3 through 6 to be medium duty, and classes 7 and 8 to be heavy duty.

Next slide, please. So, next up is a more specific breakdown of the types of MDHD vehicles we're modeling. At the top in dark blue are the broad categories of vehicle types and below them are more specific examples of our vehicle classes. For the vehicle classes, the light blue color denotes that it's included in the Freight and Truck Choice Model, which I'll be specifically delving into in this presentation.

Whereas the vehicle classes in the white boxes are covered by our other models, primarily led by my colleague Elena Giyenko. Most notably here, buses and motorhomes are not included in the freight modeling.

Next slide, please. So, before I dive into some of the individual inputs, I'd like to start with a very high level overview of how our freight and truck choice model works. This is by no means comprehensive, but will hopefully help ground some of the later slides.

So, to start, the model uses an estimated allocation of existing truck stock to fulfill a forecasted demand for truck miles needed by freight movement within the state.

Another key component of the model is the econ demo data, or economic and demographic data, which as Aniss mentioned we're pulling from Moody's Analytics. This is used to adjust the forecasted freight movement across the state and has been updated for this year's forecast.

So, after existing truck stock has been allocated, the remaining demand for truck miles then informs the required number of truck additions in each forecast year.

From there, the truck choice model takes various truck attributes, such as the delivered truck price, incentives, and maintenance costs just to name a few, to determine the fuel types of new truck additions. In other words, that's where the model is determining market shares.

All of these components feed into the main outputs of the model, which are the forecast demand for truck miles, truck stock forecast, and the resulting energy demand forecast.

Next slide, please. Next, is a deeper dive on how the forecast works. So, the graphic at the top provides a different illustration of how the forecast works.

Starting with that forecasted demand of vehicle miles of freight movement in ton miles, which we pull from the Freight Analysis Framework, or FAF, produced by the Federal Bureau of Transportation Statistics, the model then forecasts the number of trucks needed to fulfill the freight movement demand.

Then, the existing truck stock, which we base on DMV data and HVIP voucher data, is allocated first to meet demand and a new truck sales forecast is then created to meet that remaining demand.

This process incorporates truck attributes from a variety of sources. I won't read them all out, but just want to highlight a few key ones. This includes -- the data sources include CARB's EMFAC 2021 database, the California Vehicle Inventory and Use Survey, or CA-VIUS, and other staff and consultant research.

Finally, one of our key outputs that we forecast is the total truck energy by fuel type. Of course, notably electricity, but we forecast all fuel types.

Next slide, please. Moving on, here's a quick overview of the key incentives we're including for this year's IEPR.

First is the HVIP or Hybrid and Zero-Emission Truck and Bus Voucher Incentive Program, administered by Cal-START. The base voucher amounts, which you can see on the right-hand side table, remain unchanged from the 2022 amounts.

For future years in our freight forecast, the HVIP voucher amounts are scaled to the incremental truck price. That is the difference in price between the zero emission vehicles and the internal combustion engine vehicles.

Next is the CARB-administered Carl Moyer Low NOx Incentive, which ranges from $10,000 to $25,000 for natural gas vehicles.

And last, but not least, is the most recent addition of the Inflation Reduction Act, which we first incorporated in last year's IEPR update and will continue to do so this year.

Based on the language of the IRA, the incentive we're including in our freight and truck choice model will be capped at $7,500 for Class 3 trucks, and capped at $40,000 for all heavier weight classes.

Next slide, please. And can we actually go one more? Thank you.

So, next I just want to provide a slice sample of our truck price forecast using the Class 8 Day Cab Tractor Trucks as an example. These are typically the kinds of trucks that we would find being used at the ports.

So, to start, CEC's truck price forecast is based on market research conducted by consultants a few years ago, and further refined by staff.

I want to especially note that in last year's IEPR update staff incorporated the spike in raw material prices for battery packs for electric trucks. And for this year's forecast we've since updated that with more recent data.

So, looking at this graph of Class 8 Day Cab Tractors, electric trucks for this vehicle class, shown in orange, are slightly above $400,000 in 2023. Whereas diesel trucks, shown in blue, hover around $150,000 in 2023.

We've cross-referenced with purchase price information for electric trucks from HVIP data to ensure that our values are in the ballpark of actual purchase prices being seen this year so far.

In our forecast here, electric trucks reach price parity with diesel in 2032 and then dip even below diesel prices further out in the forecast.

For a comparison with other sources, I've also included projected electric truck prices for Class 8 Day Cab from a Total Cost of Ownership Study done by Argonne National Lab. These are the green dots here for 2025, 2030, and 2035. The lines between these points were just added by me to illustrate the general trend.

But as you can see, when we compare our CEC truck price forecast with Argonne National Lab, the general trend of decline generally aligns between the two in orange and green.

And can we go back one slide.

MR. WENDER: Can I just ask, Maggie, what the --

MS. DENG: Sure.

MR. WENDER: -- main driver of difference between the Argonne and CEC price models are, and is that the update that you did to account for inflation and materials.

MS. DENG: So, yeah, my understanding is I believe the Argonne National Lab might predate that raw materials spike - at least from my reading I didn’t see that being included. But I think there’s also maybe some different assumptions. I’m not entirely sure, yeah, what market research they might have based it on versus what ours is based on. Thanks for the question.

Okay, thank you. So, I just want to conclude on a comparison of our baseline forecast and the two AATE scenarios. I know this is technically focused on baseline forecast, but I thought this might be helpful for all of us.

So, as a summary here, starting with baseline econ and demo data will be used across the baseline forecast and our two AATE scenarios.

Vehicle attributes also generally remain consistent at baseline levels, with the exception being delivered truck prices for AATE scenario 2.

In AATE scenario 2 we will be using lowered truck prices in order to model more aggressive ZEV adoption. And so, this is what we did in last year's IEPR update and will continue to do that this year.

Then incentives, as I briefly went over, and truck fuel prices are maintained at the baseline for, again, forecast -- baseline forecast and the AATE scenarios.

The CARB regulations at the bottom of this table here are where the key differences lie. So, the baseline forecast incorporates the impacts expected from the Advanced Clean Trucks regulation, which has a manufacturer sales requirement for zero emission trucks.

Since the CEC -- I also just want to note that since the CEC model is demand side, the baseline forecast incorporates ACT compliance by an aggregate, by tallying new truck additions and calculating net credits statewide compared to the schedule of ACT.

And AATE scenario 2 is the same as baseline, also incorporates ACT compliance.

Now, the key difference lies in AATE scenario 3, which is our most aggressive ZEV adoption scenario. This incorporates expected impacts from the recently adopted CARB regulation Advanced Clean Fleets, or ACF. ACF includes a 100 percent ZEV sales requirement for

MDHD beginning in 2040 for different fleet types, including what CARB designates as high priority and federal fleets, public fleets, and drayage fleets there is a variety of different ZEV adoption schedules.

For our AATE scenario 3 we leverage CARB's projections of ZEVs expected to result from ACF, and assign within our model -- as a post process, we assign new vehicles sales in order to align our ZEV market shares with those projected volumes -- CARB's projected volumes of MDHD ZEVs.

So, similar to as what Aniss explained in LD, our total MDHD population remains the same, however the makeup of fuel types is what's differing in AATE scenario 3.

And can we advance two slides, please. So, that concludes my presentation. Thank you very much for your time and attention. I would just conclude by saying that we've been engaged in a lot of different conversations with sister agencies and stakeholders about the uncertainties around, you know, different truck attributes for MDHD ZEVs in particular. And we're looking forward to continuing those conversations in the future.

So, thank you for very much and looking forward to input.

VICE CHAIR GUNDA: Thank you, Maggie. I just have a few comments for us. So, just first of all I want to welcome you to the MDHD forecasting space. And also want to take a moment to thank Bob for many, many years of work and continuing to foster that. You know, congratulations to him on his retirement. And thanks and gratitude for all the good work that he's done over the years.

Wanted to direct just a quick first kind of comment on the ACF being included in the AATE 3. Which one are we baking into the forecast for the IRP? So, I mean like so when we have the scoping plan compliance for the light-duty vehicles, which AATE was it a part of and is this going to be a part of that?

MR. GEE: Vice Chair, so I don't think I quite caught that. Were you talking about -- you said IRP or --

VICE CHAIR GUNDA: Yes. So, when we send the forecast over to the forecast people to --

MR. GEE: Oh, okay. Before IRP, okay. Yeah, so AATE 3 is the transportation electrification scenario that is part of the planning forecast. It is also part of the local reliability forecast, whereas AAEE and AAFS have different scenario inputs into the local reliability.

But the goal of the AA framework is the number 3 scenario that's kind of the one that's used for IRP.

VICE CHAIR GUNDA: That's awesome. Thank you. That's clear.

And then, just on the geographic disaggregation question that came up, especially I think this has a huger impact on the local reliability, the interconnection planning. Wanted to make sure -- this is more of a comment. If you have, you know, something, a reaction, just making sure we're consistent with FTD in kind of some of their charging distribution planning and reliables. So, we have an idea, not just on the energy system needs but, you know, which areas might be constrained.

One thing I would propose for us, even though we don't necessarily have to comment beyond the forecasting zones for our forecasts, it might be helpful for us to qualitatively describe in our forecasting some areas of potential high electric growth, right, and potential congestion to be just kind of named, you know, so that we can continue to think about that.

You know, this is an evolving question and PUC's doing a bunch of good modeling, CAISO's doing modeling. But to the extent that we can just frame the question on here's some high level load pockets we see happening with the load that we're expecting will be really helpful.

The comment to Jesse, thank you for your personal story on the hydrogen stuff. I think it was really helpful to just kind of have that story of like here's how the hydrogen success, and difficulties, challenges that we have to overcome are specifically in translating that information, you know, beyond the anecdotes, just kind of broader data.

Aniss, if you're the right person to comment on, you know, how are we translating that into our forecasting inputs? You know, what's really changing in our inputs?

MS. BAHREINIAN: What we have -- we have two variables in the model that are going to account for some of these. One is distance to station, so the time that it takes to get to the station. And then, the other one is refueling time.

You mentioned, Jesse mentioned that in one of the stations that he has gone to they have put down that there's going to have to be a 10-minute gap between the fueling. So, technically, if you want to account for the full time that somebody is going to refuel, that ten minutes has to be added to the refueling time that we have for hydrogen vehicles.

And then, of course, going to Concord is going to be quite problematic when it comes to time to station. So, we are going to have to adjust those if these are permanent condition. If it is a temporary condition, remember that our forecast is a long-term forecast. But if these are temporary conditions, we wouldn't change anything.

If we get some inclination that this is going to be permanent, then we're going to have to incorporate that into the time to station and refueling time.

VICE CHAIR GUNDA: Yeah, I would think -- oh, go ahead.

MR. GAGE: And I would like to -- this is Jesse Gage. I would like to reiterate that this is just one station that's having the 10-minute mandatory wait between fill ups. Other stations -- I mean, you know, long lines can obviously impact the time to refuel. But they don't have anything absolutely crazy like I've seen over there during outages like this.

And Aniss said, this too shall pass. And, you know, look forward to getting out of this current shortage and, hopefully, things get better from here.

VICE CHAIR GUNDA: Yeah, thank you, Jesse and Aniss. I think just a comment, I think it will be helpful for us to have, you know, either, you know, in a public forum or through the DAWG, of however, just a little bit more robust discussion on hydrogen in the short term and in the long term. And in the next presentation that we come out publically, it will be helpful to kind of summarize those. I think it's important given there is a push for hydrogen economy in the state. There's huge incentives that are lined up.

And just want to have that context of both the challenges, what we expect to overcome, and the uncertainties to just be documented in a public setting would be helpful. Thank you.

MR. GEE: Vice Chair, I would also note, there -- I think that's a really good point. We'll have some qualitative discussion there, and maybe throw in some numbers to, you know, to show what's going on.

There's also a part of the IEPR that is expected to come into here, a chapter pertaining to Senate Bill 1075, that tasks the Energy Commission with commissioning a study to envision or to evaluate the -- sort of set up a scenario for what hydrogen could look like as a source for procuring power, maybe peak power, maybe even potentially baseload, and then also transportation in that framework.

And that's something that we're working on. Actually, that's another project that has fallen into

Maggie's lap, that she has graciously accepted.

But yeah, but definitely we will also want to have some discussion there. The $30, $34 hydrogen, you know, per kilogram price is -- and that has created a little bit of a challenge for us to try to figure out exactly how to assess our fuel price forecast, but we will continue to hammer away at that.

MR. GAGE: And I don't expect the $34 to last.

MR. GEE: Yeah.

MR. GAGE: I mean this is a very emergency measure that they're taking. I think what's happening is they're having a disruption of the pipeline, so they're trucking the hydrogen over.

MR. GEE: Yeah.

MR. GAGE: I'm not sure, though.

MR. GEE: Yeah, I think that's the hope.

MR. WENDER: Since we're talking about the hydrogen, I'd be curious if you could comment on the vehicle supply side and, you know, what hydrogen fuel cell vehicles are available, if any are in that more popular SUV, heavier weight range. And then, if any have been announced or are anticipated to come to market in the near term that influence your forecast.

MR. GAGE: Sure. There are two models available. There's the Toyota Mirai, and that's a compact, midsize sedan. And then, the NEXO, what I drive, which is a compact SUV. Currently, the Mirai outsells the NEXO about ten to one. I think this just might be just on brand, they're picking -- I mean Mirai is really established. It's been around for several years now and it's kind of what people default to when they think of a hydrogen fuel cell vehicle, if they think of them at all.

There was also the Honda Clarity PHEV, which was out -- I don't know, it was also quite a while ago. It was discontinued in, I believe, 2021. Don't see a lot of those around. But I hear that they're planning on bringing that back in 2024. I don't know if that's going to make it into this market or not.

I've also heard rumors from BMW. I know they're kind of proponents of hydrogen, but that might be for the European market again.

MR. WENDER: Okay, then one other question for Aniss around this question of used zero emission vehicles, and how they're treated, and what kind of fractions of sales they account for previously in your models, or if you think the model will start picking them up as a larger fraction of sales going into the future?

MS. BAHREINIAN: The used vehicle sales,

depending on what the price is and, of course, when it comes to EVs you have to also look at the health of the battery, because that means cost down the line.

As the model treats it, as it goes on it will maintain those in the market up to a certain year, and then it would get rid of them.

Whether in reality how many people, what percentage of the households are going to actually buy used BEVs we really don’t know that. We know that there are a lot of -- there are a lot of incentives in some of the areas of California. Like in Fresno, I know that there were some incentives for the used EVs.

But as I mentioned, we are not accounting for the local incentives and those are local incentives. Unfortunately, so far we haven’t figured out how to run the model with the inputs that we need for -- at regional level. And, therefore, we cannot really speak to that, per se.

MR. WENDER: I guess the last broad comment or range of questions gets to this second step after you get the energy forecast, and you start allocating that to specific times of day, and really trying to think about doing some sensitivities and evaluations around when vehicles charge, how many are charging at any given time to get a clear sense of what that means in terms of eventual procurements, or infrastructure build required, and potential savings associated with different charging behaviors.

I'm curious the extent to which that's explored as a sensitivity in the models now or could be considered going forward.

MR. GEE: Yeah, that's really important. That's an important part of the forecast, actually, the load shape work.

There weren't any major inputs and assumption modifications. I mean we're updating the time of use rates and things like that in the load model.

But basically, after we get the forecasting team's annual gigawatt hour demand, we do put that into a load shape models that determines load shapes for 8,760 hours over each forecast year.

And that is used to inform the forecast overall and sort of anticipate what's the peak day -- or, what's the peak hour of the forecast and what should we plan to.

There is -- there are some -- I think I even saw some questions in the Q&A box that kind of pertain to some of this as well. But was that all that you were looking for or was there something about the -- you're talking about the geographical distribution of this as well?

MR. WENDER: At this time I was on the temporal distribution.

MR. GEE: Temporal.

MR. WENDER: Really, the sensitivity of that and if you've explored that through these models.

MR. GEE: Yeah. We are -- one challenge I would say that we have with the load models is that they are based on time of year rates -- time of use rates. So, we have input load shapes that kind of -- that are based off real-world data with what we've seen in the vehicle charging patterns and behavior there.

But then we have time of use rates that precede that data, and those time of use rates we have good evidence that there's some responsivity. It's not perfect responsivity. It's not like, you know, from 5:00 p.m. to 8:00 p.m. rates go up by, you know, 20 cents per kilowatt hour in a given utility area, and everyone turns off the charger, right. There's still a good chunk, I don't even know if it reduces the load by half during that time period.

But, yeah, there is some sensitivity to the prices there. But what I would point out is that those time of use rates, we really only have about a six year, on a good year, we have maybe a six year time horizon, maybe only a four or five year time horizon until the next time of use cycle updates.

And so in that situation, you know, when we start forecasting out, I mean we are going to 2040 this year pursuant to new laws and requests from CAISO. We are going to go out there, but there is a caveat that the load shape model kinda can only see the time of use rates so far into the future.

And there's lots of other technologies that can deal with load management, there's lots of other opportunities around vehicle to grid, vehicle to building, et cetera. So, there's a whole lot of uncertainties on that front.

But I think what we're kind of putting forward in the load shape work that we do provide in the IEPR is kind of, you know, here's kind of a business as usual sort of approach.

And, you know, we had the SB846 Load Flex Report. We are also working on -- I'm working with staff right now, with Liz Pham and the student assistant of ours, Jeffrey Chen, who will be looking at a new type of scenario that will take into account the possibility that a good chunk of folks might engage in what we call V to B arbitrage. So, that's basically the time of use rates are bad -- or not bad, sorry. I didn't mean to say that. They're very good in a lot of ways. But they are, from an economic perspective they could be bad -- it's not a good idea to charge, unless you need to, you know, at 5:00 p.m. Why would you pay, you know, so much money when you could charge at 12:00 a.m. instead.

So, we're looking at the possibility of people actually using their batteries, not necessarily to feed onto the grid. I think that that technology and that framework right now, except for the load shape report, is a little bit conjectural. But there is a basis for a vehicle to building usage there.

And we are looking at a scenario where we're kind of -- we're going to look into evaluating what could be the load impact if, say, 5 percent, or 10 percent, or 20 percent of vehicle owners decided to say, hey, I can actually, you know, use my car as a battery and run my AC for a couple of hours off of my car. It's not going to take much out of my battery and it will save me a couple bucks every day. So, we're looking at that possibility.

MS. BAHREINIAN: Also, regarding your specific question on the sensitivity analysis, the load shape model, which is called EVIL, for no good reason-- it is called EVIL. It has price elasticity which is a user-defined field. And as of now, price elasticity that is used in the model is about 0.3, so it is less than even 0.5. We were calling it inelastic.

What that means is that if you increase the price, well, consumers aren't really going to respond that much to it. But what we can do is say, okay, what if price elasticity is .5 or .7, or 1, what are the consumers going to do.

So, for the sensitivity analysis that you were mentioning, that is something that we can do in the model. We can change the elasticity and see what the impact is going to be on the system.

VICE CHAIR GUNDA: Awesome. Thank you, Aniss and Quentin. I think, just in the interest of time we might want to just go -- oh, Commissioner McAllister, do you have -- oh, okay. And just go to the Q&A.

I think we're starting the Q&A about 10 minutes late, so I do want to give 10 minutes and then we can close.

MR. GEE: Great. Yeah, I think we actually answered some of these questions about V2G. So, the first one I see -- so, I'm going to focus on the ones that are most pertinent to the topic at hand today.

So, the availability -- Kevin Cameron asks about the V2G capability of EVs being factored into planning.

I think in terms of the forecast there isn't --

it’s not a critical component of the forecast. It’s not as if in our choice models we say this is a V2G vehicle, therefore a consumer is more likely to purchase it. So, it’s not incorporated in that way.

I think, Aniss, can you speak to -- are we -- we’re considering that in the survey, right, that possibility?

MS. BAHREINIAN: So, whenever it comes to questions like that, like V2G, how are the consumers going to behave. You’re going to have some kind of data based on which you could build a model and then do it. We don’t have any data, yet. But in the new survey that we are going to start soon, very soon, we are going to incorporate questions on V2G, the vehicle to grid, and see how people are going to behave. You cannot really predict anything if you don’t know how the consumers behave.

And so, we are going to try to capture consumer behavior when it comes to vehicle to grid activity. So, that’s a future thing. We don’t have it presently, but it is going to come.

MR. GEE: Great. Thanks Aniss.

The next question from Lauren Hanson: Tuesday’s meeting included a mention of automation of the decision process for EV owners on when to refuel their cars, which can reduce their electricity costs and flatten peak demand in critical moments. When is this automation expected to be available and how we will you account for its positive effects, if your electricity demand is on modeling this year and going forward?

So, what -- as I mentioned, we did do the SB846 load shift report, which does include those types of opportunities.

As far as the forecast goes, really at this point we have the EV load model that does a responsivity to time of use rates. We don't actually account for how consumers are likely to do that. We just assume that that elasticity in there -- or, not assume. We're basing the elasticity off of the data that we have. And we could be sensitive, we could change sensitivity there.

But what I would say is that there is a possibility of other things, what we might call smart charging, also there is the V2G arbitrage scenario that I mentioned before, and there's actual V2G. So, there's a sort of an increasing range of vehicle grid integration that we can capture in the long run. Right now, we're currently focusing just on the time of use rates.

One might argue that some of what we would call smart charging is kind of captured in that already because someone might just -- you know, instead of setting a timer, you might have -- you know, begin to participate in some kind of load program that does the same -- load shifting program that actually helps you do that more reactively. But currently not directly addressed in the forecast.

Let's see. Claire Broome from 350 Bay Area: What rate schedules do you assume for light-duty charging, default TOU or EV rates?

Currently what we do is we do use the EV time of use rates in that.

Some other questions. So, charging -- so Kristian Corby from CalETC: How are charging levels and preferences incorporated into the model?

Aniss, did you want to talk? I mean I guess --

MS. BAHREINIAN: Can you repeat the question?

MR. GEE: How are charging levels and preferences incorporated into the model?

I think Kristian means preferences for charging of specific types.

MS. BAHREINIAN: Yeah, I think that by charging level, the question must mean the difference between, for instance, level 3, level 2 and all that. We do not have -- currently we don't have any preferences for those in our model.

I know that our colleagues at Fuels and Transportation Division, they are using NREL's model, which is called EVIPRO. And EVIPRO does have a preference for the type of charging. So, that is incorporated.

And if you are interested in AB 2127, those, all of those are discussed, and explained, and projected.

But in our LDV forecast we do not incorporate it, other than, say, the time to station, and the refueling time. We are making assumptions about how many of those public chargers are level 3 and how many are level 2. So, based on those assumptions we have set consumer preferences. But in the EVIL model it doesn't do that, it doesn't have any preference.

MR. GEE: Great. Thanks.

Next one we see -- oh, this thing keeps moving on me. Yihao Xie from ICCT: How is IEPR incorporating the CPU's freight infrastructure planning proposal?

Maggie, do you want to take a stab at that or do you want me to? Okay, just in case.

But, yeah, so we are working very closely with the California Public Utilities Commission and the utilities on the Freight Infrastructure Planning Proposal. The Freight Infrastructure Planning Proposal will, we are hoping will use the IEPR results, the IEPR forecast values for that.

How to precisely do that I think is an upcoming question that we're continuing to try to work on with the Public Utilities Commission.

Kristian Corby: Can Maggie explain what she said about the MDHD population staying the same through the three scenarios? How is that possible with number 3 being the most aggressive?

MS. DENG: Yeah, I can quickly clarify that. Thanks Kristian. So, what I meant by that is that the total MDHD populations, not just ZEVs, but total MDHD population including diesel trucks, electric trucks, hydrogen, et cetera, that is staying the same. So, I don't have that number off the top of my head.

But for example, in last year's IEPR forecast, as we said, the State of California will need 1 million freight trucks to fulfill all of the freight demand within the state.

Then what's changing between the scenarios is not that 1 million total population but, rather, within that 1 million how many are diesel, how many are electric, how many are hydrogen, et cetera. So, I hope that helps clarify.

VICE CHAIR GUNDA: Yeah, Maggie, one piece there might be so those, the overall population does not stay constant in the sense that it's also forecasted.

MS. DENG: Yes.

VICE CHAIR GUNDA: It will continue to grow. But for any given year of the forecast it then kind of is distributed by technology based on the preferences and other things. Thanks.

MS. DENG: Correct. Thank you, Vice Chair.

MS. BAHREINIAN: Yeah, so one thing that I can add is that very much like light-duty vehicles, when we are forecasting, the difference between the forecast and the scenario, we said, remember in one of the slides I mentioned, that the total population is going to be exactly the same in the AATE scenario versus the forecast.

The reason why those are the same is that the starting point is the forecast and then what AATE 3 does, it post-processes those results to make the market share of the ZEVs the same as it is used in different CARB policies. That's how it works. It is because of the post-processing. The total population is going to remain exactly the same thing because it's based on the same forecast.

MR. GEE: Great. Yeah. Daniel Nelli asks: So, IEPR EV electricity forecast does not include electricity which may be used upstream to produce hydrogen for FCEVs?

Yes, that is correct. We do not. We are looking at demand for the fuel. And so, when we demand a kilogram of hydrogen, we are not anticipating the source of the hydrogen. That could be bio-based, theoretically it could be fossil-based hydrogen. I don't think that's necessarily in line with long-term state goals. But, so, for hydrogen, for electrolysis we would not be including that.

But I think the SD1075 section will probably address that. And when we work on our demand scenarios project, we will capture the electricity that's required to produce hydrogen. But for the transportation forecast, that's not quite where it's headed with that.

Kevin Cameron asks: Trucking will go battery swap.

I don't think that --

VICE CHAIR GUNDA: Quentin, that kind of hydrogen electrolysis portion ultimately gets captured in the industrial forecast for --

MR. GEE: I believe so, yes, yes.

VICE CHAIR GUNDA: It's captured somewhere else?

MS. BAHREINIAN: It could be captured.

MR. GEE: I could be captured, yeah.

MS. BAHREINIAN: But I'm not sure if it is currently captured or not. But industrial would be the good place to put it.

MR. GEE: Yeah. Last year's IEPR did not have very much hydrogen demanded, so it probably would not be a noticeable impact. But, yeah, if we anticipate more, it's certainly something for us to make sure we think about and add into.

VICE CHAIR GUNDA: Yeah.

MR. GEE: Yeah.

VICE CHAIR GUNDA: I think the demand scenario does capture that for the SB 100 purposes. But I think having a discussion on when we onboard that part of the scenario into a forecast would be helpful moving forward.

MR. GEE: Yeah, yeah. So, the forecast -- the forecast results would go -- the transportation forecast results would go into the demand scenarios. And when the demand scenarios do a more complete sort of economy-wide analysis, they'll add it in at that point, yeah.

Kevin Cameron asks if trucking will go battery swap?

We don't think -- currently not. We don't have that in the model. Right, Maggie? No. And we are not confident that that's probably where it will be going.

It theoretically could, but given the state of the power chargers that we're looking at, it might not be going in that direction.  We don't have any indication to suggest that it will.

And then, Lauren Hanson asks:  When do you expect that the 2023 IEPR and its electricity supply demand projections will be made available to the CPUC to inform decisions that agency plans to make before the end of this year?

Traditionally, the IEPR is adopted the year of the IEPR.  So, in this case the 2023 would be adopted in -- we generally plan for it to be adopted in January of 2024.  We do work with the CPUC and other agencies to coordinate on this through the Joint Agency Steering Committee.  So, I think it will be okay, we'll talk about that at the JASC, I guess, if there's a concern. Yeah.

And I think that's about all the time that we have right now for questions that relate to that.  Thank you.

Oh, sorry.  Yes.  Oh, there's a question in the room.  Is there?  Oh, are there questions in the room, any hands?  No hands.  Okay.  I forgot about in.  I'm not used to the real world.

Okay, so I think we did want to save a little bit of time for public comment, thank you. Any public comment, in-house public comment?

MS. BAILEY: I can go ahead and give those instructions again, Quentin, if you'd like.

MR. GEE: Oh, okay, great. Thank you, Stephanie.

MS. BAILEY: Yeah, so just a quick reminder, we do welcome written comments after the work shop by 5:00 p.m. on September 1st. And for instructions on how to provide those comments, go ahead and see the notice for this workshop which is posted on the CEC's website.

So, it's time to turn to public comments now. One person per an organization may comment and comments are limited to 3 minutes per speaker.

We'll start with those that are participating in person and I will turn it back over to Quentin to see if there are any commenters on his end.

MR. GEE: It doesn't look like it.

MS. BAILEY: Okay, great. So, then we'll go ahead and start with people that are participating remotely. If you are on the online Zoom platform, you can use the raise hand feature to let us know you'd like to comment, and we'll call on you and open your line. We do ask that you state your name, and spell your name, and the affiliation so that we can ensure that our record reflects the correct spelling.

And I see three hands here now. Sarah Taheri, you can go ahead. You may need to unmute on your end.

VICE CHAIR GUNDA: Sarah, if you can hear us, you may need to unmute on your end. Okay, just go to the next one.

MS. BAILEY: Okay, we'll go ahead. Yeah, we'll go ahead and go to our next hand up here. We have Hang.

VICE CHAIR GUNDA: Can we make sure that they can unmute on their end? This is the second caller.

MS. BAILEY: Yeah, I am selecting for them to unmute. Let's try one more just to make it's not a glitch on our end.

Claire Broome, I'm going to allow you to be able to talk here, if you can unmute on your end. Claire, are you there? No.

VICE CHAIR GUNDA: She was able to unmute, though.

MS. BAILEY: Oh, it looks like she's -- okay, let's see. Hmm.

MS. BROOME: Can you hear me now?

MS. BAILEY: Yes, we can. Okay, Claire.

MS. BROOME: Well, I had to -- I unmuted, then it wanted to promote me to a panelist, and then I had to unmute again. So, maybe the other people are having problems with that.

MS. BAILEY: Got it, thank you.

MS. BROOME: Yeah. Anyway, Claire Broome, C-L-A-I-R-E B-R-O-O-M-E, representing 350 Bay Area.

And I want to start by congratulating the Energy Commission staff and the Commissioners for an impressive, sophisticated, and complex approach to modeling these issues, which are so important for California’s environment and ratepayers.

Vice Chair Gunda indicated that he wants to be sure he is able in his forecasting to address potential demand, and he referred to this as a conservative approach.

However, from a ratepayer perspective, I would say the potential for over-building infrastructure is very real. So, it’s not necessarily conservative. And I know that’s why you all spend so much time trying to get the modeling right.

The two points that I wanted to comment on, where I think there might be some room to help us all succeed. First of all, on being sure you’re considering all of the resources that might be available to meet that demand.

This refers back to the Tuesday workshop, but I think there is, as best I can tell, no consideration of wholesale photovoltaics on the distribution grid, which is a resource particularly, almost equal in size that really needs to be incorporated into resource planning. Happy to provide references.

And the demand modifier side, I'm very impressed by what's been talked about for the predictions. But I think it's important to put more effort into modification of load. We talked a little bit about vehicle to house or vehicle to grid, but also behind-the-meter batteries could be used to address some of that high load for emergency reliability.

So, I would just urge the Commission to be sure to include scenarios which optimize load modification and load shaping. I think this is particularly important to both achieve California's goals, but also avoid burdening ratepayers beyond what's necessary.

The chance for load modifiers to decrease peak capacity and also to do demand flexibility during extreme weather conditions is very real.

I was delighted that Vice Chair Gunda mentioned CalFUSE. I think there's some huge potential there.

I think you're giving me more than three minutes, which I appreciate, but I will stop now and thank you very much for all your efforts.

MS. BAILEY: Thank you, Claire.

Okay, we're going to -- oh, good, it looks like Hang was able to get promoted to panelist. Let's see if we can get Hang to provide comments now. I think you may need to unmute on your end. Hmm. It doesn't seem to be working.

Okay, well let's give Sarah Taheri one more chance here. Sarah, it sounds like it may ask you to promote to panelist, and then you'd need to unmute, and then unmute again once you've been promoted. Sarah, you can go ahead, if you're there.

Okay, well, we have not had any luck with our other comments. I see no others. I guess I will turn it back over to Vice Chair Gunda for any closing remarks.

VICE CHAIR GUNDA: Yeah, thank you so much, Stephanie, for trying to do that. And to Hang and Sarah, if you -- if there was a technical issue, apologies on our end.

And Claire, thank you for your comments as well, really helpful to think through, you know, the statements I was trying to kind of make in terms of the ratepayer impacts, as well. Totally good comments on that to consider.

So, I don't want to say this is my favorite workshop, because I shouldn't --

(Laughter)

VICE CHAIR GUNDA: But I will say it’s one of my favorite workshops.

And for those of you, about 60 online still, and about 20 here and, you now, just those forecasting nerds and people who find forecasting is a happy place, thank you for joining us and providing comments.

And to the excellent DAD team, thank you for all the work that you do. And keep moving forward. Thanks.

With that, we’ll adjourn. Thanks.

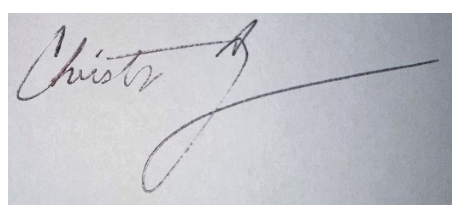
(Thereupon, the Workshop was adjourned at 4:36 p.m.)

**CERTIFICATE OF REPORTER**

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 10th day of October, 2023.



_______________________________________

Chris Caplan
Electronic Reporter

CER**1971

**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.

Barbara Little
Certified Transcriber
AAERT No. CET**D-520