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STATE OF CALIFORNIA

CALIFORNIA ENERGY COMMISSION

In the matter of,	) Docket No. 23-IEPR-03
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2023 Integrated Energy	)
Policy Report	) re: Inputs and
______________________________	) Assumptions

IEPR Commissioner Workshop on Inputs and Assumptions

IN-PERSON AND REMOVE VIA ZOOM
Warren-Alquist State Energy Building
1516 Ninth Street
Art Rosenfeld Hearing Room
Sacramento, California 95614

TUESDAY, AUGUST 15, 2023

1:00 P.M.

Reported By:
Martha Nelson

APPEARANCES

Commissioners

Patricia Monahan, 2023 IEPR Lead Commissioner
Siva Gunda, Vice Chair
Andrew McAllister

Presenters

Heidi Javanbakht, Demand Analysis Branch, CEC
Nicholas Fugate, Demand Analysis Branch, CEC
Richard Jensen, Supply Analysis Branch, Planning and Modeling Unit, CEC
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P R O C E E D I N G S

August 15, 2023 1:06 P.M.

MS. BAILEY: All right, good afternoon. Welcome to today's Commissioner Workshop on inputs and assumptions. I'm Stephanie Bailey with the Integrated Energy Policy Report Team, or IEPR for short, here at the CEC. And this workshop is being held as part of the CEC's proceeding on the 2023 IEPR.

Today we're doing a hybrid workshop using Zoom while 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 screen in the room. We're using the in-room microphones for sound also. This workshop is being recorded and 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 today, the schedule and slide decks have been docketed and posted on the CEC's IEPR webpage. So, for those in the room, we have signs with a QR code. You can scan it using your smartphone and it will take you to the CEC webpage with workshop materials. Hard copies of the meeting schedule should also be available for those in-person attendees.

So, attendees can provide comments on the material being discussed today during the public comment period at the end of the day. Please note that while we look forward to hearing public comments, we will not be responding to questions during the public 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. For those that are participating remotely, you can either use the raise-hand function in Zoom, which looks like a high five or star-nine on your phone during the public comment period to let us know that you'd like to comment. Written comments are also welcome and instructions for providing those are in the workshop Notice, and those are due by 5:00 PM on September 1st.

So, with that, I will turn it over to Commissioner Patty Monahan, the lead for this year's IEPR, to say a few words about today's workshop. Thanks.

VICE CHAIR GUNDA: Thank you Stephanie for walking us through the logistics. Commissioner Monahan had to step out just for a minute, she'll be back. This is Commissioner Gunda. I'm going to start off with the opening comments section. So just want to say welcome to everybody who is joining the workshop. We have over a hundred joined already, and staff in the room, and colleagues in the room here. Just, you know, it goes without saying, you know the forecast is the foundational basis for the energy planning in the state.

We just wrapped up a workshop this morning on the Distributed Energy Backup Assets Program, which is really looking at the reliability, but it all starts with the forecasting. I want to take this opportunity to just say thanks to the staff who have been making a number of different revisions to accommodate the changing conditions of the grid and the planning needs of the state; especially looking at more and more penetration of behind the meter solar, behind the meter storage, the electrification impacts, and the granularity that's required to do good resource planning.

So, most of the attendee understand, so the forecasting goes to PUC to, you know, to be the basis for the resource planning and the resource adequacy areas of the state's planning. And once we have that, you know, as we move towards this climate change impacts and such, we are also looking at beyond resource adequacy and IRP planning, which is what we're calling the reliability planning, and that's something that we're tackling separately. But for today we'll be talking about the demand forecast, all the adjustments that are being made, and really look forward to hearing the progress and comments.

With that, I will pass it on to the lead Commissioner Monahan who is here.

COMMISSIONER MONAHAN: I need some basic training in being in a meeting. Thank you, Commissioner McAllister. So just to build on what Vice Chair Gunda said, at least the last few minutes, few seconds that I was able to hear, you know this year's IEPR is really focused on speeding the interconnection and deployment of Clean Energy Resources on the grid. And the demand forecast is critical to kind of setting the procurement goals of the utilities, and to really laying out how much energy we're going to need in order to meet our goals, to help with implementation of regulations that the Air Resources Board is developing, and making sure that we have the right inputs into the demand forecast is really critical to this whole process. So that's what we're going to be talking about today and I'll just pass it over to Commissioner McAllister.

COMMISSIONER MCALLISTER: Well, first what they said. The forecast, you know, is just bread and butter for the Energy Commission, but I think, you know, the fact that we sort of do this, you know, sort of wash, rinse, repeat, it seems like sometimes every cycle, the forecast is really living, and it's different every time, and it's no more probably so than this moment that we're living.

And in particular just really excited, you know, the various components of the demand forecast, all of them have their, you know, details and where our staff is so capable on the analytical side of unpacking all different elements, both on the positive load side and on the negative with efficiency and demand response load shaping. Lots of really interesting components that are really coming to the fore this year as we figure out how to enhance reliability as we electrify, and as we try in earnest to build out new renewable supply resources.

So, rates, we'll talk about that. Looking forward to Lynn's presentation. And then you know really, I think we're-- we have the 7,000-megawatt load shift goal, which I think this forecast will really set the stage for a robust discussion and really deepening that analysis from here moving forward. So really, just excited to have the conversation today and beyond. I'll pass it-- let's see who we're going to, first. I think we're going to Heidi for the demand forecast overview. Great, thanks Heidi.

COMMISSIONER MONAHAN: Just want to, for folks in the room who are not able to see anything on the screen right now, we're working on that, so hopefully that'll be resolved soon. The zoom should be working fine for seeing slides, so if you are in the room and you want to see the slides, I'm sorry, but go to your computer, hopefully it'll be resolved soon.

COMMISSIONER MCALLISTER: I have pushed my computer back so I'm not scarily to the fore, so apologies for that, if anybody was scared by my ugly face.

MS. JAVANBAKHT: We just needed you all to talk a little longer.

(Laughter)

Okay, so I can kick this off and the slides will catch up. So good afternoon, everyone. My name is Heidi Javanbakht, and I'm the Manager of our Demand Analysis Branch. I'm going to start us off by presenting an overview of the 2023 Energy Demand Forecast, as well as the forecast updates for this year.

Next slide, please.

Our forecast work is underway. We've had three Demand Analysis Working Group meetings over the past few months, and materials from those meetings are posted at the link at the bottom of this slide. This workshop today is the first of a series of IEPR workshops on the forecast. We're doing things slightly differently this year where we've split our workshops across two days. So today is the first day of the Inputs and Assumptions Workshop, and today we'll cover common inputs across all the forecast models, and then we have a second Inputs and Assumptions Workshop on Friday to cover the load modifiers.

We've also split our Results Workshop across two days. The first workshop will happen in November and will focus on the results of the Load Modifier Forecasts and the second Results Workshop in early December will review the overall forecast results. And then with our usual timeline, we will aim to post the final results in January and then present those results at the January business meeting for adoption.

Next slide, please.

Okay, so today's agenda is to go over at a high level how the forecast is produced. We'll then give an overview of the major improvements that we're making to the forecast this year. Nick Fugate will present the updates to historical energy consumption and the economic and demographic projections. After that, Richard Jensen will give a presentation on the production cost modeling, followed by Lynn Marshall's presentation on the inputs and assumptions for the retail electricity rate forecast.

Next slide.

Friday's workshop will cover methodology updates to distributed generation, climate change, the hourly load forecast, additional achievable energy efficiency and fuel substitution, and the transportation forecast. I'll touch on these really quickly today and briefly, but ask that questions and comments on these topics be held for Friday's workshop.

And next slide.

So, jumping into some background on the CEC's forecast, and thanks to Vice Chair Gunda for already touching on this a little bit. The California Energy Demand Forecast often referred to as the CED or the IEPR Forecast, is foundational to procurement and system planning in the state. It's used by the CPUC for integrated resource planning, by the California ISO for transmission system planning and by the CPUCs and utilities for resource adequacy requirements, and by the utilities for planning.

The forecast is a 15-year forecast of both electricity and gas demand in the state. We project annual electricity and gas consumption and hourly electricity loads. The forecast includes scenarios reflecting various levels of adoption of energy efficiency, building electrification, and transportation electrification. The forecast also includes one in X year net electricity peak estimates.

Every two years during the odd numbered years, we do a full refresh of the forecast, and that's what we are doing this year for the 2023 forecast. Even number years are update years where we do not-- we don't update all the components of the forecast, allowing the team to have some time to make model improvements.

And next slide.

In recent years, extreme weather events are occurring more frequently, not just in California but across the globe. This leads to increased uncertainty in grid planning and a need for our planning processes to continuously adapt. As an example, the heat event last summer by the 30-year historical record was a one in 27-year weather event. However, we recognize that extreme weather events are occurring more frequently than they did over the last 30 years, and that historical weather data are no longer sufficient for predicting future weather patterns. And at Friday's workshop we'll discuss updates to the forecast to better reflect climate change impacts on energy demand.

Next slide.

At the same time that we are experiencing the impacts of climate change, the state is strategizing on how best to meet economy-wide carbon neutrality by 2045. Many of the strategies impact energy demand, and we've seen an uptick in policies and programs aimed at increasing energy efficiency, electrifying buildings and transportation, solar PV and battery storage, and ways to shift load to off peak hours. As these new policies and programs are developed, they are incorporated into the forecast. Because there is uncertainty around how decarbonization policies and programs will be implemented or how the market will respond, we attempt to capture that uncertainty through various additional achievable scenarios, and those will be covered in more depth on Friday.

Next slide.

This chart highlights the impacts of adapting our forecast over time due to evolving planning needs. Each line in this chart is the forecasted net peak demand for the California ISO region from previous IEPR forecasts going back to 2018. Since 2018, each subsequent forecast has had an increase in forecasted net peak demand due to various changes. I'll start with the most recent changes. We first incorporated the Air Resource Board's Advanced Clean Cars II and Advanced Clean Fleets regulations in the 2021 additional transportation electrification scenario, which is the green dash line on this chart. That was also included in the 2022 IEPR forecast, which is the orange line. Those regulations account for the majority of the increase in net peak demand from the 2021 IEPR forecast. The 2021 IEPR forecast also introduced the additional achievable fuel substitution load modifier to capture building electrification impacts.

Another change during that year was update to the peak normalization process where we sampled recent years in the 30-year historical weather record more frequently to better capture climate change. Another notable observation between the 2018 IEPR and the 2022 IEPR forecast is that behind the meter solar PV capacity has increased. this has shifted the net peak hour from hour 17 to hour 19 when solar production tapers off for the day. Lastly, all of this is entangled with growth in the underlying baseline consumption forecasts built from economic demographic and rate projections.

Next slide.

I am going to shift gears now to go over the forecast approach at a high level setting the stage for the rest of the presentations today and on Friday.

Next slide. Oh, one second.

VICE CHAIR GUNDA: Just on the question on the terminology of net peak here, would you just kind of expand what net peak in this context means?

MS. JAVENBAKHT: Yeah, it incorporates the solar PV generation. So, it's the total consumption minus the solar PV.

MR. FUGATE: Minus behind the meter resources.

MS. JAVENBAKHT: All behind the meter resources.

VICE CHAIR GUNDA: Yeah, not the supply side.

MR. FUGATE: Right.

VICE CHAIR GUNDA: So yeah, I just wanted to make sure that I think we don't have anybody confused because we are using the net peak terminology on the supply side. Thanks.

MS. JAVENBAKHT: Good clarification. Thanks.

Okay. We produce a system level forecast, and our forecast is for eight electricity planning areas and eight gas-- sorry, four gas planning areas. On the electricity side, this includes the three IOUs, Northern California Non-CAISO, which we refer to as NCNC, LADWP, Imperial Irrigation District, Burbank/Glendale, and Valley Electric Association.

On the gas side, it's the three large gas utilities in the state plus an "Other" category to capture the other regions.

Next slide.

The common level of geographic granularity across all our forecast models is the Forecast Zone. These are based on planning area boundaries in addition to climates. And I will note that these zones are different than climate zones used for energy codes and standards.

Next slide.

I'm going to quickly cover forecast terminology. The sector models are forecasting total or baseline consumption, and this is before PV or other load modifiers are taken into account. When we layer the behind the meter distributed generation impacts on top of this, this brings us to Baseline Sales. After that, we layer on the impacts of the additional achievable scenarios for energy efficiency, fuel substitution, and transportation electrification, and that is referred to as the Managed Sales.

Next slide.

The next few slides, we'll walk through the forecast model system. The starting point for the models is the historical electricity and gas sales data reported by the utilities through the Quarterly Fuel and Energy Reports, or QFER. We add to this our estimates of historical behind the meter distributed generation to come up with historical electricity and gas consumption. The historical consumption data are provided to the end use and NAICS code based forecast models.

Next slide.

Economic and demographic projections. Oh, one more slide ahead. Okay. Economic and demographic projections from Moody's and the Department of Finance are inputs to the models, as well as forecasts of electricity and gas rates. These are the inputs that the workshop today covers.

Next slide.

Committed energy programs, codes, and standards are taken into account in estimating energy demand for each sector. We also account for the Title 24 mandates for PV and storage for new construction.

Next slide.

Additional achievable scenarios are developed for energy efficiency, fuel substitution, and transportation electrification. These scenarios are for impacts above and beyond the committed energy programs such as proposed programs and regulations, capture— sorry, such as proposed programs and regulations such as the proposed zero-emission appliance regulations proposed by the air districts. That's a good example of the types of things that are in these scenarios.

Next slide.

The load modifiers in the orange boxes are combined with baseline consumption to create the managed annual sales forecast scenarios. And this is the end result for the gas forecast. The electricity forecast has one additional step.

Next slide.

The hourly load model is run to create the managed hourly load forecast from which we extract net peak demand, and from here we also estimate the one in X year net peak demand.

Next slide.

Moving on now to talk specifically about the updates that we are in the process of implementing for the 2023 IEPR forecast.

Next slide.

For the 2023 CED, we are adding additional years to the forecast horizon and forecasting out to 2040. This is to support the California ISO's transmission planning process per SSB 887, which was passed last September. We are also conducting another round of the long-term demand scenarios to be completed next spring and are extending projections out to 2050 for that work. The long-term demand scenarios feed into the assessments for SB 100.

For the 2023 CED, we are using a framework similar to the 2022 IEPR forecast. In 2022, we moved from using a low, mid, and high case of economic and demographic projections to just one baseline or mid case forecast. The low and high case from previous IEPR forecasts were not being used, and we wanted to focus our time and energy on capturing uncertainties from decarbonization strategies. So, building from the baseline forecast, we layer select additional achievable scenarios to create the managed forecast for different use cases.

The Planning Forecast is used for Resource Adequacy and Integrated Resource Planning. This forecast will use Scenario 3 from each of the additional achievable modifiers. Scenario 3 for these load modifiers has also been referred to as the mid scenario.

The Local Reliability Scenario is used for more geographically granular studies, such as the California ISO’s Transmission Planning Process. The Local Reliability Scenario will use AAEE Scenario 2, AAFS Scenario 4, and AATE Scenario 3, resulting in a more conservative forecast with higher demand in order to account for increased uncertainty when looking at a smaller geographic granularity. And again, the inputs and assumptions for these scenarios will be discussed Friday, and you can get a better understanding of the differences between those scenarios at that workshop.

Next slide, please.

Each year that we update the forecast, we add an additional year of energy sales and consumption data, we use more recent economic and demographic data, and update the electricity and gas rates projections. For the 2023 CED, we are using Moody's economic projections from May. The Department of Finance released refreshed population projections a few weeks ago, which we will use. They have not yet released new household projections, and so we derived household projections based on their population numbers. We understand that DOF is currently working on refreshing their household projections and may releasing these data in early September.

This would be pretty late in our forecast process to incorporate new data. We typically prefer to have all inputs nailed down by around this time each year to allow us to stay on schedule. So, depending on that release date, we'll consider whether it's feasible to incorporate their numbers into the forecast.

Lastly, there are updates to the historical electricity and gas rates and updated assumptions for future rates. The gas rates were presented at an IEPR workshop on April 18th, and the electricity rate assumptions will be presented later this afternoon.

Next slide.

We have a few significant model changes to our forecast this year. The first is a refurbished residential end-use model, which was modernized to use the R programming language, it was previously in FORTRAN, and incorporates data from the latest residential appliance saturation study. The residential model was presented at a demand analysis working group meeting on August 8th, and you can find slides from that meeting using the link from slide two for the DAWG meetings.

The second change is the incorporation of new climate simulation data and re-characterization of normal and extreme peak events, and these will be discussed Friday morning. And in addition to that, we held a DAWG meeting on June 1st, which was dedicated to the priority climate change updates to our forecast model where we also laid out our plans for the next few forecast cycles to improve how the forecast accounts for climate change.

Next slide.

We have several updates to behind the meter PV and storage. And again, these will be discussed more Friday morning. At a high level, these include an improved process for determining historical capacity, which resulted in slightly lower estimates of PV capacity and higher estimates for storage capacity.

Also, over the past year, we've been working with the National Renewable Energy Laboratory to adapt their dGen model to California, and that model is ready for us to use for the 2023 CED. The adaptions include the Net Billing Tariff, as well as extension of the ITC. The dGen model doesn't include standalone storage, so we are also in the process of developing a model for standalone storage.

Next slide.

Lastly, the additional achievable energy efficiency and fuel substitution projections will be refreshed to reflect--

VICE CHAIR GUNDA: Heidi? For the-- I mean you said we're going to talk about the behind the meter storage and all the next workshop?

MS. JAVANBAKHT: Yep.

VICE CHAIR GUNDA: Just at the 30,000 foot level, how are we-- what goes into charging and discharging patterns of behind the meter storage? What's primarily driving that?

MS. JAVANBAKHT: Nick might be better to answer that question.

MR. FUGATE: So, the dGen model is not an hourly model, it's an adoption model. So, the results from that will be informing our forecast of adoption of these resources. And then in terms of the charge and discharge patterns that go into our hourly model, at the moment we are still modeling the residential sector using assumed arbitrage with latest time of use rates, and also assuming paired PV. And then in the commercial sector, we have been using charge-discharge profiles by market segments taken from Self-Gen Incentive Program impact studies.

VICE CHIR GUNDA: I think for-- I mean I'm sure the slides for the 18th workshop are pretty baked, but kind of digging into that a tiny bit for the workshop would help, given the interest in how much we have right now. I think it's 1,400 megawatts now behind the meter storage roughly in 2022? I think? So, we are approaching, you know, over a thousand megawatts and kind of getting a sense of what the load modifying element is and whether-- what level of error we're okay with at this point.

COMMISSIONER MCALLISTER: I want to just chime in. It's a great question, a rich topic. I'm wondering just you have-- is there data? Are there date sources for how people are actually dispatching? You know, charging, discharging their batteries? And, you know, maybe from the SGIP evaluation, or you know some of the solar companies maybe have generic data that they're monitoring? I mean, because they're all paying attention to their systems, right? Are there any partnerships there?

MR. FUGATE: Yes. So, data is certainly the limiting factor for us and why we have been relying on the impact studies, which do actually include metered systems. So, it is based on actual system performance data. But you know in looking at the reports to date, I mean you can sort of see in the profiles what appear to be kind of a mix of strategies, charge-discharge strategies. You know, some backup power, some peak shaving, some rate arbitrage.

So, you know in terms of turning that into a forecast, you know a forward-looking forecast, you sort of need to segment that and determine for each. You know, you have these capacity projections, but then for the different segments, what are the most likely strategies is going to be? So that is-- I don't think we're going to have a lot on that on Friday, but certainly it is on our minds.

COMMISSIONER MCALLISTER: Okay. I think just both Vice Chair and I have a strong interest in figuring out. So, we're going to talk about the rates as they are today, but sort of what potential areas for getting people who are just backing up and not arbitraging to actually do some of that, like how much that would cost and what that would look like as we scale up these demand side programs. But I guess that's a tangent really from what we're talking about today.

VICE CHAIR GUNDA: Yeah, and then I think--

COMMISSIONER MCALLISTER: Really rich discussion.

VICE CHAIR GUNDA: --not to kind of like over focus on that one right now and then we'll have whatever discussion we have on Friday. Just the high level stats that you're seeing on, you know, what percent is discharged or any NVP (PHONETIC 33:41). And, like, is there any information for us to understand, you know, what is being, what-- as you said, there are variety of strategies that are being used in discharging. Do we know if they're in programs or not, right? But we might not have it for Friday, but just flagging that as like a really helpful discussion moving forward into reliability and resource planning.

MS. JAVANBAKHT: So just to add to this, the distributed generation team has been incredibly busy with all the updates that I just mentioned on the previous slide. This is on their radar for revisiting and updating in the future, but it's probably not something we're going to get to this cycle.

Okay, this is my last slide, so let me just finish up here and then I'll hand it over to Nick. Okay. So, the additional achievable energy and fuel substitution projections will be refreshed to reflect the most recent codes and standards and incentive program data. This team is also working with the Air Resources Board to refine the modeling assumptions for the proposed zero emission space and water heater regulation. For transportation, the additional achievable transportation electrification scenarios will be updated to account for the clean miles standard, which applies to companies like Uber and Lyft and sets a target for the percentage of electric miles driven.

Next slide.

That's it for my presentation. We are going to move on to Nick Fugate next. Nick is the Chief Forecaster within the Energy Assessments Division, and then we will take questions from the dais after Nick's presentation.

MR. FUGATE: Thank you, Heidi. Waiting a moment for the next slide. Perfect. So good afternoon, Commissioners. I'm here-- oh, I'm sorry. Lemme turn my camera on real quick. We're all new at this. So, I am here this afternoon to give a brief overview of the economic and demographic scenarios we are planning to use in this IEPR forecast cycle to drive our baseline demand models.

Next slide. Let's go one more.

So, we review these scenarios every cycle because they're a critical input to our forecast. At an annual level, consumption tends to trend with economic activity. So here I'm showing statewide electricity consumption, historical consumption, against a background shaded to indicate periods of economic retraction as measured by decline in gross state product.

So, you'll notice that those periods are also marked by declines in electricity demand. And similarly, consumption rose during periods of strong economic growth in the late nineties and early to mid 2000’s. And consumption grew slowly during the 2010’s, during the long slow recovery from the 2008 housing crash. Each of our sector models is constructed around a specific set of economic indicators most relevant to that sector. So, I'm going to be covering some of the key indicators in this presentation.

Next slide, please.

Our selection of economic scenarios is similar to previous cycles. We're planning to use Moody's May vintage of projections, specifically their baseline scenario for our economic drivers. The key assumptions underlying this scenario appear still to be holding. This includes the Fed targeting interest rates at 5.25 percent, a full employment economy, which puts the US unemployment rate at about 3.5 percent, and no significant shocks to global oil prices. Oil prices have risen from about $70 a barrel earlier this year to about $80, and they may continue to rise, but this is in line with Moody's expectations so far.

One of the key risks in play during May was that the US could potentially default on its debt, but that was averted in June when the president signed a US debt ceiling bill. And we continue to look to Department of Finance to provide population and household projections.

This cycle was a little unusual. The cybersecurity breach at Department of Finance significantly impacted their schedule, and we did not start the year as we normally would with new population and household scenarios. We had discussed this issue with stakeholders at a DAWG meeting earlier this year. At the time, we did not know when to expect updated projections, and so we had proposed to retain the same population and household projections we used during the 2022 IEPR cycle.

Just last month, however, Department of Finance published an updated population forecast. This is late in our cycle, but we still have enough time to incorporate this new outlook into our modeling. What we don't have yet is an updated household forecast from DOF. Updating the population forecast without updating households would create a pretty significant inconsistency in our assumptions. And so, what we have done is calculate persons per household from DOF's previous projections, so the population and household scenarios that we used in IEPR 2022. And then we applied that to the new population forecast from DOF to derive a projection of households that is hopefully more in line with what we should expect.

DOF has indicated that a new household forecast may be available as early as the end of this month, but possibly that could be into September. Incorporating a new household forecast at this point would be pretty challenging. Our modeling work is already well underway, but we will be on the lookout for it regardless to see how closely our population derived projections align with DOF's revised outlook.

Next slide, please.

VICE CHAIR GUNDA: Nick?

MR. FUGATE: Yes?

VICE CHAIR GUNDA: If at all there is discrepancy in that, that would be in the outliers, right?

MR. FUGATE: If there is significant discrepancy? Well, yeah. So relative to-- yes. So in the very near term, we should be relatively close because we are still benching. Even with this process that I described, we are benching the resulting series to DOF's most recent estimate of 2022 household levels.

VICE CHAIR GUNDA: And the 2022 DOF assessment, did that include the push by the administration and the legislature for more housing build out? I mean, like how does DOF consider those things? Like is that evolving in the legislature?

MR. FUGATE: So, the 2022 household estimates, it's a historic estimate, so it doesn't account for--

VICE CHAIR GUNDA: No, like the previous vintage of the DOF projections. Do we know how forward looking they were in terms of some of the legislative elements being proposed on improving the household stock in California?

MR. FUGATE: In the previous vintage? I can't say for certain. I haven't looked too closely at the assumptions that were underlying the previous household projections from DOF. But certainly that's something that we can, once we receive their new forecast, either later this month or next month, we can have some discussions with them about how affordable housing policies or other strategies factor into their thinking. But what I'm presenting today is-- does not take that into account and is just derived from the population projections.

VICE CHAIR GUNDA: Thank you.

MR. FUGATE: Okay, so here I have a list of some of our key drivers: gross state product, personal income, employment population, and households. These are the most impactful econ demo drivers for our baseline consumption forecast. So, I'll be talking about each of these in the coming slides, but wanted to give an overall snapshot of how they're all trending relative to last year's IEPR forecast.

In absolute terms, some of these are actually higher, but since we benchmark our model output to actual base year consumption, it's the annual growth that matters for determining growth in the forecast. And you can see that across the board we're seeing similar or slower long-term growth across our key drivers. And I should note here, and I have to apologize, there's an error on this slide. Commercial employment grew at 0.7 percent annually under the last forecast, CED 2022, not the one percent that's shown here. I didn't catch that until a little bit before this workshop. So, there's not quite as much distance between that driver between the two vintages.

Next slide.

On this end, for the next several slides, I'm comparing a particular indicator across vintages. So, the 2023 CED versus the 2022 CED update, and showing both within the context of the historical record. We're taking the forecast out much further this cycle to accommodate longer term transmission studies, which is why CED 2023 shows five additional years of data.

Gross State Product or GSP is used in a number of our models. It contributes to our agriculture, industrial, mining and TCU forecasts, TCU being our Transportation Communication and Utility sector. We also use GSP as a benchmark to translate between nominal and real dollars over time.

Here we can see Gross State Product starts at a slightly higher level in the base here than previously projected, but long-term growth has slowed from 2.5 to 2.1 percent annually. Moody's baseline forecast assumes the Fed will achieve its goal of reducing inflation without precipitating a recession, but accounts for elevated interest rates and tightening credit conditions.

Next slide, please.

We typically think about personal income either on a per capita or per household basis depending on the modeling effort. This is a particularly important driver for our residential demand modeling, both in our end use and econometric models. We had a slight dip in per capita income from 2021 to 2022, but per capita income actually starts at a higher level than previously projected in part due to federal stimulus spending. Long-term growth rates are similar. This new scenario grows just slightly higher than last year's vintage, but both are right around 1.8 percent annually.

Next slide, please.

Employment contributes significantly to our commercial floor space model as well as many of our econometric sector models. Again, our starting point is slightly higher than previously projected. California has now recovered all the job losses incurred in the wake of the COVID 19 pandemic. The long-term growth rate is a bit lower than CED 2022 levels, half a percent annually, down from 0.7 percent.

Next slide, please.

So here is population, which is-- it's another driver that impacts a number of our models either directly or through the calculation of per capita indicators. As I mentioned earlier, we look to the Department of Finance to provide California's population outlook. There are clear differences both in starting level and long-term growth. The new projection takes into account the substantial losses that occurred, losses in population that occurred over the last two years.

We were fortunate enough to have the US Chief Demographer join one of the panel discussions at our IEPR workshop on California's economic and demographic outlook earlier this year, and provide some insight into their view of California's population outlook. While recent increased rates of domestic outmigration have slowed, long-term growth remains low, particularly over the next decade, reflecting the high cost of living, housing affordability, low fertility, and an aging population. Long-term growth in DOF’s new scenario is about 0.2 percent annually, down from what was nearly half a percent in CED 2022.

Next slide, please.

And so, finishing up with households. So, this is not the same as building stock but rather occupied households. So, households impact our forecast of PV and personal electric vehicle adoption, but has the most direct input impact on our residential sector demand forecast. Both our econometric and end use models predict household energy use. And so, the forecast is actually derived by multiplying our model output by our household outlook.

This is the forecast that I mentioned we derived from Department of Finance's July population outlook. We calculated persons per household from the previous vintage of DOF’s population and household projections, which is the forecast we used last cycle, and then applied that persons per household essentially divided it into the new population forecast, and then benchmarked the resulting series to DOF’s most recent historical estimate of occupied households in 2022. So, as you'd expect given the new population scenario, the resulting growth is lower than projected last cycle, 0.6 percent annually down from 0.9 percent.

Next slide.

So that was the last of my slides. I'll wrap up just by reiterating that long-term growth across all of these drivers is similar to or lower than our previous vintage of drivers. Heidi described earlier in her discussion of our forecast framework, you know she showed that there are quite a lot of load modifiers that go into our final managed forecast. So, we start with a baseline forecast, but then we layer in self-generation, additional achievable modifiers, which now include significant amounts of electrification, and then also climate impacts, which we are currently in the process of refreshing. So that's another plug for our Friday workshop.

So, this isn't the whole picture, but based on the inputs today that I presented, it would be reasonable to expect that this will exert some downward pressure on the baseline component of our forecast. So, net of all those other demand modifiers.

MS. JAVANBAKHT: Thanks Nick. And so, with that, we will go to the dais for discussion and questions.

VICE CHAIR GUNDA: We were asking questions as we go. I don't--

COMMISSIONER MCALLISTER: Yeah, we're pretty conversation--

VICE CHAIR GUNDA: I don’t have any.

COMMISSIONER MCALLISTER: I mean, this is a pretty intimate conversational kind of setting.

COMMISSIONER MONAHAN: Yeah, I actually prefer it to the stilted dais.

VICE CHAIR GUNDA: I like this.

COMMISSIONER MONAHAN: Yeah.

COMMISSIONER MCALLISTER: That's why we joking.

COMMISSIONER MONHAN: If you guys are okay with it being more, just as questions come up and comments come up. Okay.

COMMISSIONER MCALLISTER: We have plenty of time.

VICE CHAIR GUNDA: When you said dais, we were joking that it should be a round table.

MS. JAVANBAKHT: Yeah, I know we're right next to each.

COMMISSSIONER MCALLISTER: You have time for public comment though, right?

MS. JAVANBAKHT: Yeah. Well, we have a couple of questions in the Q&A, both are for Nick. So, I'll read those. And then if there's anyone in the room who would like to ask a question, you can go up to the podium and use the mic.

So, there's a question from JP. It says, "In this slide with the drivers—" Oh, okay. "In the slide with the drivers, how does per capita personal income remain constant if commercial employment decreases?"

MR. FUGATE: Apologies. I'm trying to pull up the questions here on my screen. I don't have a definitive answer to that. It seems possible if wages are increasing. But that is-- I would have to dive more into the assumptions and, you know, more detailed assumptions underlying the different--

COMMISSIONER MCALLISTER: If there's a more specific question sort of in there, maybe you can rephrase and ask again. But it seems like those are relatively-- I mean they're related, but they're not the same thing. So, certainly logical that that could take place.

MS. JAVANBAKHT: Okay. And we'll go to an in-person question, and then we'll loop back to the other online question in a moment.

MR. MCRAE: Thanks. My name is Tim McCrae, I'm with this Silicon Valley Leadership group. Okay. My name is Tim McCrae. I'm with the Silicon Valley Leadership Group. Still working with the mic. Heidi, I noticed in your presentation that you broke down things by climactic zone. And I'm wondering how geographically specific you have data for things on the economic projections that you're making? How much geographic specificity do you have? Is it built from all these different climactic zones? Or is it more just looking at things at the state level?

MR. FUGATE: Yes, so thank you for the question. The data-- all of our data comes in at the county level, and we then aggregate it to our forecast zones and build our forecast room from there.

MR. MCRAE: Thank you.

MR. FUGATE: And I can respond to Patrick Cunningham's office. So, I think probably what you're looking at, if this is a CAISO report. Oh yes, I'm sorry. So, question reads, "The CAISO's Department of Market Monitoring reports modest decreases in annual total energy since 2020, but the CEC is showing increases since 2020. Has non-CAISO state demand been increasing relatively significantly? Or is there some other explanation or data consideration?"

And so that's-- the chart that I was showing was consumption, which is sort of a counterfactual estimate that we put together. Most of our modeling is built around consumption, which is basically what end users are actually-- the demand on the customer side of the meter regardless of how that energy is being supplied. But a significant portion of demand is being met now through behind the meter resources, and that would not show up in the CAISO data. So, our consumption estimates are always higher than estimates of system load, and the difference is essentially the behind the meter generation.

VICE CHAIR GUNDA: Nick, maybe you want to just comment on why we use the consumption versus the CAISO sales data?

MR. FUGATE: Sure. Just because it gives a better actual picture of what, you know, the behavior that we're trying to model.

MS. JAVANBAKHT: There are no other questions online. Is there anyone else in the room who would like to ask a question? All right. It looks like we are ready to move on. So, our next presenter is Richard Jensen. Richard is a senior analyst with the Planning and Modeling Unit, and will be talking about production cost modeling.

MR. JENSEN: Good afternoon, everyone. Good to see some faces in person that I have not seen for a number of years here. It's comforting to see you all here. Yes, Richard Jensen. Not the Demand Analysis Branch, but the Supply Analysis Branch, we used to call them offices way back when. I guess we’re now branches.

But if we could-- do I, oh, here we are. Advance these other slides.

But I first wanted to thank the team behind this, Mark, Nani, and Hannah and the rest who've recently departed have been a big part of all these input updates and helping get the slides put together for today's presentation.

Next slide, please.

So, no results today. Obviously, inputs are the focus and not many numbers. I do have a slide later to illustrate the quantities of renewable energy that we're introducing in our production cost model. And I will try to weave the comments from Commissioners about the advancement of clean energy resources and how we can use our production cost model to take a look at what's going on, especially as we get further and further out. So, I'll keep that in mind as we move through looking at the model that we use and the settings, data inputs and the sources where we derive those and some of the assumptions that we make.

Next slide, please.

PLEXOS is our model of the last 12 to 14 years; production cost model, meaning it's economic driven. We're trying to get the market clear-- not market clearing prices, rather the wholesale price of energy. We use least cost dispatch optimization, so always looking for the least expensive next unit of energy to meet load. It is used widely throughout California and the west, PG&E, Southern California Edison, Southern Cal Gas, SMUD. So, it's been around a while proven, but of course only as good as your inputs and assumptions. We do provide a IEPR database to the public, it provides publicly available data. And it is-- we will provide that to anyone who asks, but the only catch there is you must license PLEXOS to use or read that database.

I would say that at times we are asked to use this product to produce things that maybe it was not designed for. And while it may give a look at certain outputs, I do caution that the further we get out in years 10, 15, 20 years and the types of data that we're looking at that, that may not be its best use, it is a production cost model. So, when looking at things like GHG emissions, I know there's been efforts over the past several years to look at hourly GHG emissions. I would caution that this is a deterministic model, and we use one wind shape, one solar shape, one load 0.2 to get our results.

Next slide, please.

COMMISSIONER MONAHAN: Can you go back?

MR. JENSEN: Oh, yes please.

COMMISSIONER MONAHAN: Can I just ask a quick question on that? Just go back. So, I mean I've been really impressed with the team's work to make all of our energy data more transparent and accessible. Is there any movement on this front? The fact that it has to be licensed, you have to be licensed to read and to use, has there been any thinking about how to move to a more publicly accessible source?

MR. JENSEN: No. No, I half joked there. You know, our inputs are available with their Excel-based CSV type files.

COMMISSIONER MONAHAN: Mmm hmm.

MR. JENSEN: But the product itself that reads it in its entirety, a license is required. We do our best to produce the results to everyone. Of course, as you know in a readable concise format. We are open to questions. As a team, I believe we have a specific email account designed to answer questions regarding our database. But there is no way currently to look at the data base itself without a PLEXOS license, if that answers your question.

Moving on the next slide, please.

So yeah, the uses and users here, and I mentioned the greenhouse gas emissions. I'm far more comfortable in looking at annual or seasonal numbers when looking at that, and not unit specific. This model does a very good job of estimating near term things. Again, the further you go out and the assumptions that you make can have more robust or less robust results. But it's a system-wide look, in my opinion, for many things including the emissions.

We do iterate with the natural gas team for the gas price forecast for California as they use our gas consumption for utility electric generation as an input. So, we work back and forth with the gas team in trying to better those numbers.

Wholesale electricity prices for rate forecasting, I think Lynn will probably touch on that next. And the Efficiency Division has used our data in the past, our results in the past for the time dependent valuation work. Users, academic institutions. I just provided the database and files last night to a couple of students at Stanford University, which is both terrifying and exciting because I appreciate what they're doing, and I hope they find some errors and point those out, and I'm sure that they will.

California Electric and Gas utilities, I mentioned a few of those earlier. And now consulting firms are starting to show interest as well. In particular those that work with the smaller entities, community choice aggregators, CalCCA, I was on a call with them a couple of weeks ago with their consultants. So not having the resources to license and run PLEXOS, turning to consulting firms is something they're doing. So, the better product we can provide them on the deterministic side, IEPR database as we call it, the better their work will be.

Next slide, please.

Just a bit in the weeds but not too deep here.

COMMISSIONER MCALLISTER: Can I ask you a quick question, Richard.

MR. JENSEN: Oh yes.

COMMISSIONER MCALLISTER: Sorry. So, what's the iteration with a user like that? Do they come and say, “Hey, we want to run a particular scenario and we do it?” Or do we just say-- do we just have, I know there's a bunch of scenarios that we typically routinely do, but like--

MR. JENSEN: You’re referring to the--

COMMISSIONER MCALLISTER: -- a portfolio of scenarios sort of evolving to look like.

MR. JENSEN: Are you referring to the consulting firms that would use it on behalf of another?

COMMISSIONER MCALLISTER: In part, I guess.

But I guess I was understanding that we were producing sort of output.

MR. JENSEN: Oh no.

COMMISSIONER MCALLISTER: Okay, so we're just providing--

MR. JENSEN: We’re providing the database and the files at any question they have, and then they can--

COMMISSIONER MCALLISTER: And then they can go to the consulting firm and say we want this.

MR. JENSEN: --right, right. And I would say the last conversation I had with a consultant, they are looking far more deeply into the economics, which is an area that we have struggled with over the years. So, providing information to us from what they're seeing is very helpful to us.

COMMISSIONER MCALLISTER: Yeah, exactly. That's kind of where I was going with that.

MR. JENSEN: Symbiotic relation.

COMMISSIONER MCALLISTER: How much back and forth are we having with those users for those consumers of our work?

MR. JENSEN: Yeah, but to be clear, we're not running simulations on behalf of any other entity.

COMMISSIONER MCALLISTER: Okay, great. But do we gather their sort of perspective to develop our own scenarios?

MR. JENSEN: To this point, no. This is my-- unless it's been a contracted consulting firm that is doing work on behalf of another division or our office, no.

COMMISSIONER MCALLISTER: Okay, good. Thanks.

MR. JENSEN: For modelers out there or anyone interested, regional aggregations, loads and resources, so large utilities or balancing areas is how we put our hubs together. We'd be looking at Southern California Edison, Arizona Public Service, Balancing Area in Northern California. It's that level of granularity, if you will. Again, deterministic studies that are not the reliability stochastic where you're running hundreds if not thousands of simulations. We do model every hour of the forecast horizon.

PLEXOS uses a one day look ahead to inform. So, if it's anticipating a large outage draw the next day or there'll be a spike in loads at the beginning of a heat event. Or if you're getting toward the end of the month, perhaps hydro resources have used a good chunk of its energy for that month. The look ahead will give it a crystal ball effect, so you can use that one day.

Now any attempt to lengthen that does slow down your run times considerably. Run time is currently about two hours per year. And that is-- one reason for that, as I mentioned here in the last bullet, a linear modeling approach, meaning that PLEXOS can dispatch a partial unit or use a sweet spot on the heat rate curve to meet that next unit of energy. The alternative to that would be to turn a unit on or off.

I've tested that many years ago. The differences were slight, and the runtime is an exponential increase. Instead of the two hours per year you're looking at, if I'm not mistaken, it's eight to 10 hours per year. Of course, we're using upgraded computers now, but again, the linear approach is a significant savings in runtime.

Next slide, please.

So, some of the data sources, data and sources that we use: of course the demand forecast, which was the focus, primary focus today; hourly for the IOUs, we do have to develop at this point the hourly POUs, and that's using a load shape derived from five years of historic data for those publicly owned utilities; PEC; natural gas prices, QFER. Mike Nyberg's team does a great job and we use the historical gen for the past couple of years. Keeping in mind that loads may have been a little higher or lower, hydro may be better or worse, but we can use that to calibrate against the first few years of our simulations to see if we're close. But again, the further you go out in the horizon that the more iffy it becomes.

Also, and I'll show a bit here, I do have one number slide today, the PUC preferred system plan used as a guide to guide renew energy additions. The Western interconnect data from WECC and EIA, a good source for that is the anchored dataset. The one issue with that is they're one year, 10 years out. So currently the production cost data subcommittee is looking at 2034 as the year they're running. Well, that doesn't do us a lot of good in 2030, et cetera. But we can use that as a gauge/a guide to get to that point.

The demand forecast that we use a combination of EIA and the WECC loads and resources subcommittee that collects that data. Some of it is that the near-term years are confidential, so we have to massage that back in a little bit, and they don't always go out as far as our simulation horizon. So, at times there is a need to build peak in energy out in the latter years, which can be a little tricky.

Also, EIA or rather a state level information for RPS and clean Energy, noting that the IEPR this year focusing on clean energy resources and implementation, other western states, in particular Washington and Oregon, looking at clean energy standards. Colorado has a pretty robust, fairly robust RPS as well. And then you're seeing other players jump in there. So, the changes in resource profiles, the availability of renewable energy inputs, so panels and wind turbines and things like that. As other states ramp up theirs, it could be a challenge just as an aside. But they have many states now looking at that.

VICE CHAIR GUNDA: Richard, just on the-- so for the gen there, so just kind of backing up just a tiny bit. For the PLEXOS model, for the purposes of developing the forecast for the gas consumption, this is gas consumption for thermal fleet, right?

MR. JENSEN: Yeah, utility electric gen, yes. With the Jennifer Campana team. Yes.

VICE CHAIR GUNDA: So just want to make sure then, did I understand that we use a point forecast for the demand in this? So, when you run this, are we using a single demand forecast? And then for the historical gen data, we're also using a single point, for example, wind and solar or hydro? What are the profiles we're using?

MR. JENSEN: Right. So yes, the demand forecast, one point forecast to develop the gas burn going forward that we pass back to the natural gas team. For wind, solar, we have profiles that are built. Again, much like the POU load for files built with five years of data. Aggregating that in certain areas to keep it-- to protect anything that may be deemed confidential, and to create a larger wind resource area or profile. Comparing our results on an annual level to QFER is very beneficial. So, you can go back a couple of years, especially for wind and solar and we're very close.

The wild card of course is hydro, which we use an average of 15 years of monthly generation data. And you will note when you look at QFER that there is no sort of mode, right? It's either high or low. It's 42 or 39, or it's 15 or 16. It's very seldom 27 or 29, which is right about where our average is. So hourly profiles built, developed by the team based on five years of data.

VICE CHAIR GUNDA: Sorry. And then, so the natural gas prices, so like you know, the volatility of the prices last year that we've seen, right? Like in December or a couple of years ago, what kind of impact do they have on the dispatch? I mean, one of the struggles is, is it truly kind of elastic like when you actually do-- I mean, the production cost model is simulating the least cost dispatch, right? But in reality, you know, does it pretty closely track?

MR. JENSEN: California wide? Yes. If our inputs for other things-- recently we had a bit of a-- we put in too much renewable generations and I was like, well, why is the gas burn so low? Well, we went back and found we had a little too much. So, we backed that out, here comes the gas burn at a far more acceptable level. Again, when you compare everything, generation resource types.

We do not model those sort of volatile events. We are getting the annual price monthly from the burner tip model, and those are massaged out during the process of creating the gas prices. So, we're getting a monthly look at what is a reasonable, I guess you could probably say a one and two gas price forecast. I don't want to speak for the gas team, but you're not seeing large spikes. You do see price increases throughout the year, and you do see in general an increase of those gas prices over time throughout our forecast horizon.

VICE CHAIR GUNDA: The last question. On the imports, are you using an hourly profile too for imports?

MR. JENSEN: No, the imports are coming as economically desirable into California. I'll touch on that here in just a moment as well.

VICE CHAIR GUNDA: Thanks.

MR. JENSEN: With that, I think next slide, please.

So probably a bit of an underused source at this point are the utility Integrated Resource Plans, which are valuable, but there are many, they are lengthy and there's a lot of detail. You'll see a business as usual case, a high economic case. You'll see, a well, we're going to meet an outstanding renewable target case. So, it makes it difficult to pick one out. And they're not uniform in any way between states. Some are filed every two years, some every five years is the requirement, and they'll have differing lengths of those filings. You'll see some that will go out quite further than others.

Sticking to the preferred plan is usually the way to go. Interesting of late though, so with the change in system and retirements of large coal plants, and the consistent growth in the desert Southwest, one Utility Resource Plan I looked at, actually, I believe it was their business as usual case. They said, "Look, we're short in 10 years." That was never the case. You would never see the red numbers in there beneath their peak load or their energy. There was always some assumption that they would meet it with a gas or coal-fired resource. But I thought that was interesting to c a major utility say, “We know we're short, we just don't know how we're going to meet it just yet.”

And that, in this type of modeling, needs to be looked at in terms of the, I hate to use the phrase planning reserve margins as we know those can be tricky, but in other forums I have heard states, utilities consulting, consultants suggest that WECC-wide, Western Interconnect-wide, we could be seeing some diminishing reserve margins and available energy for California, which has hopefully been the case.

Next slide, please.

So physical system input, some examples of those and where we get that data.

COMMISSIONER MCALLISTER: Richard, can I butt-in real--

MR. JENSEN: Of course.

COMMISSIONER MCALLISTER: I just want to put in real quick. On that last point, is that just sort of a feeling that's going around? Or is that actual analysis that WECC has been doing? Because they've been trying to pull together a lot of the different forecasts and having to kind of translate between them, and—

MR. JENSEN: Yeah, you know, I tuned into some of the-- I don't want to confuse the Western Electricity Coordinating Council with the Western Interconnect.

COMMISSIONER MCALLISTER: Yeah.

MR. JENSEN: Sometimes I use those interchangeably.

COMMISSIONER MCALLISTER: You know, WECC has been pulling together all these—

MR. JENSEN: WECC's been doing some reliability studies, and they've been warning about this. But I've also seen, again in other forms, one in the northwest in particular, what, was a year or two ago when they're like, look, you may not want to depend on us 10, 15 years out. We're seeing coal plants retiring, we're trying to get away from gas. We may not have the 24/7 hydropower that's always been available. In light of things like climate change, load growth, you're seeing smaller utilities up there too, taking on-- oh, the-- as part of one of the warehouses for data, forgetting the name of them, server farms if you will.

COMMISSIONER MCALLISTER: Oh, yeah.

MR. JENSEN: Some of those are starting to pop up. And of course those have 24/7 requirements, climate controlled, et cetera. So, it's been a-- you know, I try to listen in on what others are thinking. Excuse me. And it's been an issue that's been brought up a few times in the last--

COMMISSIONER MCALLISTER: Something we-- I mean, I think in these west-web forums, we can like WECC looks to the various west-wide coordinating groups amongst the states and everything to help them define what they ought to be on. Right? So maybe we should be drilling in on that if they're-- I think they're already looking at it, but it'd be--

MR. JENSEN: The reliability--

COMMISSIONER MCALLISTER: Yeah, it'd be to--

MR. JENSEN: --if you will. Right.

COMMISSIONER MCALLISTER: It'd be good to get a check in with them on that. Thank you.

MR. JENSEN: Welcome. Again, where we can use QFER data for our inputs, EIA for others. In that first bullet point, you know, the efficiency of power plants, we try to update the heat rates based on EIA data, sims data. Planned retirements are always fluid, especially in the coal fleet. And then again monthly hydro generation, we make those assumptions for a 15-year average for not only California but Pacific Northwest as well.

One area we might want to take a closer look at is how we're modeling Hoover. Of course, we all have seen the stories regarding the low levels of the low water levels at Hoover. Demand profiles using Nick and his team's forecast. And for the hourly for the IOUs developing POU shapes, and then for out of state the anchor dataset and the data that's collected by the loads and resources subcommittee as part of the WECCC. And load modifiers, I’ll be tuning into that Friday, Thursday or Friday for the load modifiers workshop.

Modeling system constraints. So, talk about California generation, and are we getting the right levels of generation compared to history? One thing we do occasionally is put our thumb on the scale and keep some of the region’s load met by in-state natural gas. That is because if we do not, PLEXOS will tend to favor some out-of-state resources from time. We will see that import number creep up when we know in fact that some of these power plants in the state are running. And while PLEXOS does a good job, it is not perfect and it will always select the next least-cost resource, whether that's instate or outstate. And import and export limits. I believe during the peak hours for California, we limit that number to about 15,000 megawatts, and exporting, net export limit of about four or 5,000 megawatts.

Next slide, please.

Some of the economic variables and their sources. Fuel price, we mentioned natural gas, coal and uranium prices, which are not as significant inputs as they used to be given the changing system from EIA. Wheeling rates, sadly we lost our economist. She left us a couple of weeks ago now to go back to school, but she was really getting a handle on how to develop and input wheeling rates for transportation calculations. Of course, we don't have any cost for internal flows between the IOUs or POUs in California.

COMMISSIONER MONAHAN: Can you say what a wheeling rate is? Wheeling rate would be the cost of moving energy from one tack area to another. We actually use a hurdle rate, which combines that with a CO2 cost adder as well. So, you're looking at the amount it would cost to ship a megawatt hour from one location to another, say Arizona public service and the ISO. So, the economic input's not my specialty. I've always passed that off to someone. But again, we just lost our expert a couple of weeks ago.

So, the CO2 prices as a part of that, we use the California, and I believe Alberta still has a CO2 cost that they produce annually. Other costs are variable operation and maintenance and start costs. We rely heavily on the anchor data set for that. And then to adjust for inflation, we use the Moody's Deflator.

Next slide, please.

So, some assumptions. Generic, unnamed, yet to be built additions, in state, out of state for California and other states, those locations and resource types and amounts. Put in a resource build and test it and see what the results look like and maybe make some adjustments to that. But keeping in mind we need to be close on state RPS quantities every year, or at least every couple of years. And with hydro, a monthly average forecast by plant for the last 15 years. And those policy driven assumptions again, which are becoming more prominent now, especially throughout the west.

Next slide, please.

So not a lot of-- this would be the only numbers slide in the presentation here, which was by design. Just to look at some specific years and the types of resources that are added. And this is--

VICE CHAIR GUNDA: Oh yes, just one question. Just going back to that imports question. So, like as you are kind of developing the production cost model results, you have the demand, you have in-state generation that you're all baking in. So, for imports because it's economically dispatched, is there a limit that you put on the imports? Or if it just goes all the way to MIC?

MR. JENSEN: The imports are limited at time of system peak, or so many peak hours by the MIC. Other hours are not. But given that California has a considerable amount of in-state resources, hydro generation or renewable resources, hydro generation, efficient gas, it's not that we-- no, we do not dictate the import limit for our production cost model. It is in a sense free flowing with some exceptions for those peak hours.

And there is a component to the wheeling rate that is added, sort of a commitment adder for units out of state, that increases that rate just a bit to prevent too much economic energy from flowing into the state. And this is a modeling tool that others have used that we have seen in a couple of different studies. Again, because PLEXOS is very good at what it does, and that's finding that cheap energy to move to the place to keep costs down. Because California's cost normally significantly higher than it would be to send elsewhere. So, in looking at the system at its entirety, California being such a large entity, it's moving power there, but there are tools at our disposal and general requirements in state adders to the wheeling rates.

VICE CHAIR GUNDA: Got it, thank you.

MR. JENSEN: So, this slide just oh, yeah.

COMMISSIONER MCALLISTER: So, if there were just a run-on new construction, you know, outside of the state, and like it was very low cost or something. In theory, could there just be-- could that displace in-state resources?

MR. JENSEN: If you had zero cost for transmission?

COMMISSIONER MCALLISTER: Yeah, I mean the wheeling rate provide--

MR. JENSEN: That's your buffer, right?

COMMISSIONER MCALLISTER: That's barrier, right?

MR. JENSEN: That's what’s pushing back against it. Because that-- the fleet that we have, so much renewable energy, again, hydro all the nuke that's going to run.

COMMISSIONER MCALLISTER: In-state's going to just win in that.

MR. JENSEN: Yeah. Given that economic disincentive to import.

COMMISSIONER MCALLISTER: This is not exactly on point, but I guess I'm wondering how are you tracking the greenhouse gas content of imports at this point?

MR. JENSEN: That work has not been updated in a little over a year. It is on our list of to-dos, but we lost our expert. As you know, Angela Tanghetti retired about a year and a half ago and she was a key member of that team. Unfortunately, the person who left a couple of weeks ago was sort of her backup or replacement. So, work that we will need to again revisit, but we can make assumptions about the greenhouse gas emissions from various resources. Not to get too far into the weeds, but our transmission system is broken up into the actual system line and then dedicated lines that bring renewable energy that are contracted with out of state. So, if there's an out of state wind resource, we bring it in through that line. Those are tagged with varying levels of GHGs so that we can say, well over the course of a year this much is accountable from that line coming from the northwest or southwest.

COMMISSIONER MCALLISTER: Okay, that's helpful. Thanks.

MR. JENSEN: So, these numbers taken from, I believe a report, SB 846, from a few months ago. Thanks to Hannah for putting this together. You can see the cumulative additions here are significant. And you know, where do we put them? Well again, it's trial and error. A lot of the solar has to go in the sunny areas, the wind has to go in the windy areas, et cetera.

One other factor you're seeing here now up here in 2030 is the-- I'm sorry, in 2026, is the offshore wind. When you get to significant quantities of that, you start seeing some changes to the flows on lines. Something we're mindful of, but we're starting to put in resources with very similar profiles in large quantities, and that has an impact on where energy flows, where it is needed at certain times. So, this is part of the work that will be ongoing to ensure that we're not passing off databases to those who need them with things that should be addressed. Or at least the caveats associated with it.

Next slide, please.

Quickly, we do have the planned retirements and additions. There's a fuel switching considerable that went in Alberta. Now that doesn't have necessarily an impact given its transmission. Interconnections are with BC and Montana, that's not a huge electric issue. But if you're switching from coal to a lot of gas up that way, you may see some northwest gas flowing that way at times if Alberta finds it economic to do so.

Of course, the once through cooling units are always on mind. In our deterministic database, the natural gas units, once through cooling are essentially retired. We don't anticipate them running because we don't use a forecast, a load forecast, that would trigger that. And as far as Diablo Canyon at this point, the latest simulations that I pass the results off and then the database that we're using retires in 2024 and 2025. Of course, that's subject to extension.

Transmission expansion. This is something that needs to be addressed, but for the time being, we'll follow the lead of the Anchor data set. They do collect data regarding transmission expansion from their utilities, if I'm not mistaken.

Next slide, please. And that's the end of my presentation. Be glad to take any questions or comments.

VICE CHAIR GUNDA: It was, first of all, nice to see you, it's been many years. And thank you, that was really a helpful presentation. The one element for, you know, discussion outside of this meeting just kind of thinking through, is kind of the volatility of the gas prices, right? That question. The in-state gas storage, especially with the resolution in front of CPUC to double the Aliso Canyon storage. I mean how does this play into the overall, you know, gas burn and other things that'll be helpful to just understand for policy reasons? Not for forecasting, but it'll be good to talk. Thank you.

MR. JENSEN: Yeah, sure. The price is, of course, something that would impact our studies. But, you know, that-- we do not model gas storage of course. We assume that for our power plants, gas is free flowing and available.

VICE CHAIR GUNDA: Yeah, I think at least the hypothesis there is, if we had a lot of gas storage, you know, you could mitigate the volatility of the gas prices in real time and so keep the gas prices low overall. At least that's what the system sees. I think that's the IDM and it has an indirect implication into the overall effect. So, thank you. That would make sense to me.

COMMISSIONER MCALLISTER: That was great, Richard. Thanks very much. Unfortunately, I have to head over to the Cal EPA building, so I'm going to miss the rates, but I'll make sure to listen in and let you know if I have any questions ex post. Thanks Lynn, sorry to miss.

MS. JAVANBAKHT: Okay, moving to the Q&A, are there any questions in the room? It doesn't look like it, but you have time if you change your mind. We've got several questions online in the Q&A box.

The first is from Claire Broome. "How does least cost dispatch compare wholesale resources such as in front of the meter PV, on the DG, not requiring transmission with resources requiring transmission?"

MR. JENSEN: I'm reading that question properly. We do not model the DG system where we model the bulk electricity system. And any resource that is renewable is dispatched. It would not compete.

MS. JAVANBAKHT: Thanks, Richard.

MR. JENSEN: And Claire, I hope that answers your question. If not, you can follow up with that.

MS. JAVANBAKHT: The second question, this one is from Kyle Navis, and I apologize if I'm pronouncing your name incorrectly. "At the Public Advocate's office at the CPUC, have you made any cost modeling assumptions related to the start of the extended day ahead market in 2025? If not, when do you anticipate incorporating its impact on the markets?"

MR. JENSEN: We do not. We don't model markets. This is not something we would have the resources or the ability to do at this time.

MS. JAVANBAKHT: Next question is from Jamie Randolph at PG&E. "Are you going to include hydrogen for long duration energy storage and power gen from hydrogen?"

MR. JENSEN: I believe there's a position that has been created within our branch that will look at hydrogen resources specifically. And yes, to answer your question, eventually we would include those as part of the resource build. But I don't have a timeframe on that.

COMMISSIONER MCALLISTER: Before I leave, could I ask a question about that? Actually, you know the-- I mean, SB 100 is going to start up here pretty soon. And sort of the-- how are you thinking about the sort of clean firm, you know, in those out years, you know, 10 years and beyond? What is being-- what is PLEXOS grabbing at that time?

MR. JENSEN: Well, it's not a capacity expansion model.

COMMISSIONER MCALLISTER: Oh, right.

MR. JENSEN: It runs what we feed it.

COMMISSIONER MCALLISTER: Right.

MR. JENSEN: We would need more--

COMMISSIONER MCALLISTER: What are you feeding that in 2040 or whatever?

MR. JENSEN: Right, right. So, one issue that my colleague, Mark Kootstra has brought up, is we would have to incorporate the-- if you wanted to do it at scale, the amount of hydrogen that would have to be produced in order to feed those generators, and how much more renewable energy? Or how would you do that? Because it has to have a fuel type, and it has to run.

COMMISSIONER MCALLISTER: At what cost, right?

MR. JENSEN: And at what cost, right. Yes, exactly.

COMMISSIONER MCALLISTER: Okay. So, it's still kind of undefined with some assumptions that are sort of generic in a way?

MR. JENSEN: We have none of those resources in our database.

COMMISSIONER MCALLISTER: Oh, okay.

MR. JENSEN: At this point, it's a talking point amongst the team.

COMMISSIONER MCALLISTER: Okay, got it.

MR. JENSEN: And I would assume that filling that position would probably get us a little further along.

COMMISSIONER MCALLISTER: Thank you.

MS. JAVANBAKHT: Okay. Richard, I'm going to loop back around to Claire's question. She added a few more comments in here. She says she's asking about bulk in front of the meter. I don't know if that clarifies the question for you.

MR. JENSEN: So, we model utility scale PV as a must-run resource. It will operate and provide energy to the bulk transmission system to meet load, and it will only be curtailed if it is economic to do so, or necessary. At this point we're not seeing that as an issue. So, we're not talking about-- I understand your question is not for behind the meter PV. We do model utility scale solar in front of the meter; no cost, must run resource.

MS. JAVANBAKHT: Okay. And then one more question from the Q&A, and then we'll move to the raised hands. Rae Brigham, sorry if I'm mispronouncing that asks, "Will you be releasing additional information regarding import assumptions and modeling?"

MR. JENSEN: No plans for a report at this time, but you can always reach out Richard.Jensen@energy.ca.gov, and we could have a conversation if you'd like about that. But nothing in the works as far as releasing any reports. But the next study I guess on our plate, SB 100, is coming down the pike. So please submit your questions in that forum as well.

MS. JAVANBAKHT: Yes. Okay. We have one question in the room.

MR. MCRAE: Thanks. Again, on the geographic specificity of data, it sounds like you were saying that you break down the forecasts by utility and by balancing authority. Is that correct? And then you build up the large forecast from there. Is that the level of specificity that you get to?

MR. JENSEN: If you're referring to the region's comment that I made?

MR. MCRAE: Yes.

MR. JENSEN: Right. So, Edison, PG&E, LA, Burbank/Glendale, and resources are added to those to meet load.

MR. MCRAE: But you don't specify within the utilities or the regions, correct?

MR. JENSEN: Yes, we do. For-- Edison has its fleet, PG&E has its fleet, San Diego has its fleet. The smaller you know, we don't differentiate between SMUD and MID, it's bank. We don't differentiate between Los Angeles, Burbank and Glendale, it's LABUGLE.

MR. MCRAE: That's helpful. Thank you.

MS. JAVANBAKHT: Okay. And we will move to attendees that have their hands raised. The first person I see again is Claire Broome. I think you should be able to unmute yourself.

MR. DE: Okay. Actually, this is Dilip De. I have a question. Will the California Energy Commission fund a project of prototyping a new electrical generator that is based on a new novel technology which is outside those that have been considered? Now, for example, in our startup company, scientists and engineers have, you know, invented mostly theoretically, we have all the designs, processes and components, everything sort out and the theoretical foundation laid for a new technology that will clearly give us energy generation, electrical power generation, in any amount that we desire, just utilizing the ambient heat energy of the air. And it'll run in closed cycle continuously. It is completely new and unheard of, but we are sure that if we receive a small funding, we can prototype the generator and show that this novel technology, the first of its kind in the world will work.

So, what it does, it draws the energy from the ambient heat of the air at the room temperature, and it converts it to energy at, you know, for electrical power. And also, it is good for-- it will be good for future automotive and transportation. It’s a hundred percent clean and it'll cost much less than the conventional solar and the wind energy and the fossil power energy technologies. And we want to show this technology that it'll work. We just need a small funding. I don't know whether-- since it is outside those that are discussed or known, and will the California government be willing to fund such a project?

MS. JAVANBAKHT: Thank you Dilip, for your comments. Again, we are trying to keep this panel focused on the Energy Commission’s work on the inputs and assumptions for the California Energy Demand Forecast today. If you'd like to integrate this into a public comment on the record, please feel free to do that during the public comment using the Zoom's raise your hand feature, and that will be at the end of the workshop today. And then Claire Broome, were you also trying to ask a question?

MS. BROOME: Yes. This is a question. So, for Richard Jensen, what I'm asking is when you have bulk generating resources, for example PV on brownfields or on highway right of ways, I would assume since it will not require transmission, it should be cheaper than PV, which requires transmission. How does your production cost modeling consider such resources? I would note that tracking the sun, the Lawrence National Lab now differentiates PV that is on the distribution grid, but not behind the meter from PV that is utility scale requiring transmission.

MR. JENSEN: So, we don't include fixed or capital costs. Our model operates with only variable operation maintenance start cost, fuel costs. So, PV is a free resource in a sense in our model. That should answer your question.

Claire, were you still there? Hopefully that does answer her question. And Claire, if you have any-- need further clarification on that again Richard.Jensen@energy.ca.gov. Thank you.

MS. JAVANBAKHT: Alright, and we have one more question in the Q&A from Joseph Yan. “Richard, do you plan to release the input data for your modeling?”

MR. JENSEN: We can provide input data to anyone who has a PLEXOS license via the PLEXOS database. If you need specific input data, we can get that to you as best we can in Excel format. But the plans to release it right now, it's basically on request.

MS. JAVANBAKHT: And looks like we don't have any other questions. We will move on to Lynn Marshall's presentation. Lynn Marshall is the Resource Adequacy and Rates Principal in the Energy Assessments Division at the CEC and will be talking about the electricity rate inputs and assumptions.

MS. MARSHALL: Thank you. So, our forecasting electricity rates is basically a forecast of revenue requirements divided by a forecast of retail sales. So, we're starting with information provided by the utilities and other LSEs on their resource portfolios, their projected costs, and revenue requirements, and we're combining that with staff assumptions on power prices, fuel prices, and carbon and other escalation assumptions.

So that produces revenue requirements forecast by utility. We allocate that to individual sectors, and we divide that by our sales forecast. We're using the CED 2022 mid case forecast escalated out to 2040, and then we combine that and calibrate it to recent historic electricity rates. And that feeds into our various sector models and our load modifier models, probably in particular the self-generation and the transportation demand forecast models.

Next slide.

So, I'll talk a little bit about recent trends in electricity rates and then move on to some of the forecasting assumptions. So, I'm showing here the TAC area is the same as our PG&E planning area. So, the IOU rates that I'm showing here are the average of bundle customers, CCA customers, and direct access customers. So those LSEs report their energy revenues separately from the UDCs, which report the wires revenues. So, these rates have to be constructed from those different data sources. And then we also have about 20 percent of the publicly owned utilities in that area.

So, looking at the PG&E rates, you notice that steep upward trend in recent years. The great bulk of that, although not the only driver, are wildfire related costs. And that includes wildfire liability insurance, catastrophic event recovery, and then expenditures to mitigate wildfire risk, grid hardening, et cetera. So that's been significantly more. PG&E has a general rate case pending that's actually delayed. So, we can expect onward increased approved spending in that next case.

Next slide.

For the SCE area, we see similar trends. The last rate case-- these last two PG&E and SCE rate cases were the first to fold in the results of the PUCs risk assessment process. So, these are the revenue increases. Those are higher than what we historically would have seen. We have residential rates increasing an average over the-- 15 percent over the last three years.

POUs have, in both this and the PG&E area, have stayed relatively stable. If you look at the graphs for 2020, ’21-- for 2021 and ‘22, you see even the POU rates starting to tick up, and they've also been hit by the recent rise in power costs, both energy and capacity costs.

Next slide. Yes?

VICE CHAIR GUNDA: Lynn, just kind of going back a couple slides just on the way we construct the rates. Right? So, at the end of the day, this exercise is to make sure we have a good correlation between the demand in the past and being able to build into the future. So, when we take the revenue requirements, do we undercut the demand flexibility at all? Like are the TOU impacts? Or is that something that we figure out later? Is it just two separate processes? How do you think about the TOU impacts?

MS. MARSHALL: Well, that would be on a forecast basis included in the sales forecast. And then part of constructing the revenue requirements is you're forecasting revenue requirements to meet the demand forecast, and that includes peak and energy. So, to the extent that load flexibility reduces the peak demand, that's going to be reflected in, let’s say lower capacity costs. So ideally, we have parallel assumptions in both the demand forecast and the revenue requirements forecast.

VICE CHAIR GUNDA: And then between the two complimentary efforts there, we completely account for that? In our models, we have pretty good confidence?

MS. MARSHALL: In our forecasting, I think we're being consistent. But I would point out that when utilities set revenue requirements, they take their demand as fixed. So, they would not-- so for example, if you have a large rate increase, an economist would say, well, demand will be lower because prices are higher. They don't do that. You kind of get it into an inclement loop with the rate cases. So, they completely ignore price elasticity. But, you know, you update this every year. But on a forecast basis, we can make sure that projected load shift is accounted for on both the demand and the supply side.

VICE CHAIR GUNDA: Great. So, I think the reason why I'm kind of raising this is kind of the same effort on the behind the meter storage. Right? So, I think the evolving paradigm that we are kind of trying to get into the resource planning is, you know, we as a demand forecasting team for the state have a good handle on the consumption forecast and the load modifiers and we are doing a good job there.

But then with the demand flexibility, we are kind of thinking about two more elements. One is the resource adequacy planning. But then beyond that, what is available for emergencies if we were to play further incentives beyond rates and capacity payments? And so, I'm kind of just future proofing or thinking forward on our analysis. How do we, one, quantify the opportunity for behind the meter storage, you know, and other electric loads to be able to support extreme events? What's the universe of it and how do we operationalize that? So that's kind of where those questions are coming. So, you know, maybe it's a completely different discussion.

MS. MARSHALL: Yeah, well there's a question there of what load flexibility we would include in the forecast? And this comes up in the resource adequacy context to count something against, you know, reduce the RA forecast. It's not just something that's available occasionally on an emergency basis, it's something that's systematically reducing peak load. So, that’s that. There's a threshold test there I think we'd want to meet.

VICE CHAIR GUNDA: And Lynn, just reminding myself. So, when we have the TOU rates and stuff, the way the utilities develop the rate design is to be net neutral, revenue neutral?

MS. MARSHALL: Revenue neutral. Right. So, I'm showing here our forecasting annual average rates to meet the total revenue requirement. Then when you do your rate design, whether it's a new time of use rate, et cetera, you want to make sure that you're going to collect the same amount of revenue. And again, that's what they're going to assume. No price response, which is not right, but it's simplifying the assumption. So, it did that, for example, for cost effectiveness evaluation for load management standards, we take our rate forecast, construct a forecast of TOU hourly prices, but it's assumed that it's going to meet the same revenue target as the annual average forecast.

VICE CHAIR GUNDA: Right. So just yes-- summarizing this for myself. So, the exercise we go through in developing the rate forecast, the method we use ultimately is used for capturing the total energy, right, that is used and then the impact of this on that. And then to the extent that we are shaping that for the hourly model, that's where the actual rate design comes into place to understand a little bit more on the load modifier. Is that correct?

MS. MARSHALL: Yeah. Well, we're not doing typically much rate design.

VICE CHAIR GUNDA: Agreed. But the impact of the rate design on the hourly impact of the load is taken into account in a separate step.

MS. MARSHALL: Yeah. Right now, we don't really have that kind of effect in our modeling. We did when they were doing the residential time of use rollout, it wasn't baked into the recorded loads. So, we had a forecast of TOU impacts that went into the hourly load model. And so that when we were forecasting revenues requirements, we're using that-- actually the final demand forecast from the last cycle the way we have to start off. But yeah, so then it's the reduced peak demand is accounted for as we're procuring-- costing out resources to meet the demand forecast.

VICE CHAIR GUNDA: Thank you.

COMMISSIONER MONAHAN: Okay, I'm going to bring it down a level than the Vice Chair in terms of his questions. So, I'm struggling with what-- so in our demand forecast, we're getting new data from the utilities about time of use rates that we're going to be incorporating in. And the part that confused me was you said that, well number one, that we're assuming that this is all going to pencil out. Like have a-- in a perfect world, really we would understand, or the utilities would understand when they develop their rates, how this is going to influence consumer behavior, and they would end up with the same income stream, shall we say. That seems hard to swallow.

MS. MARSHALL: Yes. Okay. So, this is an issue in some of doing rate design for say a new electrification friendly rates.

COMMISSIONER MONAHAN: Mmm hmm.

MS. MARSHALL: And it's why that, you know, some parties have been concerned about widespread adoption of, say, something that's very attractive to— say, behind meter storage. So, what they'll do often the PUC will say, okay, let's do this as a pilot basis for a limited number of accounts and then we're going to track the shortfall to see if this rate design is in fact revenue neutral or if it's having, you know, cost shift to other customers. If that's happening, then you want to tweak the rate design going forward before you expand it to a large number of customers.

So yes, the concern about cost shift is there from, you know, other parties. So, they take kind of a gradual approach in implementing that type of rate.

VICE CHAIR GUNDA: I mean one is the cost shift, but I think-- are you asking if the revenue neutral is not real, that there might be more revenue coming in?

COMMISSIONER MONAHAN: Or less.

VICE CHAIR GUNDA: Or less, right. And so that's something that they will take into account--

MS. MARSHALL: Yeah, so if there’s--

VICE CHAIR GUNDA: -- with verification too.

MS. MARSHALL: If there's less revenue collected, that's got to be paid by somebody because the utility is still going to get it, right? And so, it gets shifted on to other residential customers who maybe can't afford behind the meter storage. And so that's why they'll on a year-to-year basis track the effects of that to, you know, at least limit the extent of the cost shift on a pilot basis because then you want to redesign the rate.

COMMISSIONER MONAHAN: And did I hear you also, I definitely could have misinterpreted this, that there's an assumption of inelasticity of demand with price?

MS. MARSHALL: Well, on a rate design basis, they don't know. And year to year that's what they take a demand forecast, the take a sales forecast and take it as fixed and don't try to bake into a price response. But of course, you know, you get a year into it, you get, especially if you're doing a pilot rate, you get pilot studies. And then that response, whatever it is, becomes baked into the recorded data and then you're forecasting off of that.

COMMISSIONER MONAHAN: And when will we start? I mean, so right now we are using our models to forecast demand, assuming some elasticity of demand with rate. And when will we have data that will give us more input, you know, give us more information about whether the accuracy of this? I mean this has to be something that's iterative. And as you note we're going to learn every year.

MS. MARSHALL: Are you talking about like time varying, right?

COMMISSIONER MONAHAN: Mmm hmm, yes.

MS. MARSHALL: Okay. So, for the residential default, there were lots and lots of pilot studies. It took probably a lot of years longer than we thought we'd roll out, but the benefit of that, it was well studied. So, there were a lot of good data points to benchmark to. And I would say for some of-- and there's new pilots going on. So doing the pilot studies and doing the rigorous load impact studies is really critical for us then to benchmark a forecast to. And, you know, we'll see I guess in a year two, three, what the results of those pilots are. Is it-- you know, are there significant enough results that we want to forecast that?

And then of course you also want to forecast will customers actually sign up for this rate? Is the other dimension too, including something in our forecast.

VICE CHAIR GUNDA: Yeah, Lynn. But skipping to Commissioner Monahan’s Point, currently you do bake in the results of everything that you have, Right? Like the pilots, you try your best. Like I remember like the SMUD studies and stuff that you tried to glean from.

MS. MARSHALL: Yes. So far, it's just been the residential time of use was modeled and forecasted out. But we'll be watching the pilots that are going on now to see when and at what point it's appropriate to use those results to forecast.

COMMISSIONER MONAHAN: I know this is an issue the US Department of Energy cares a lot about on the transportation electrification side, just really understanding how time of use rates influence customer behavior regarding charging.

MS. MARSHALL: Yeah and that's-- we'll talk about that a little bit when we get to that hourly wholesale price forecast. That's something I know our-- we're not talking about transportation a lot this year, but they're definitely paying attention to what our price assumptions are in the transportation hourly modeling. What I would say-- so what's important, you know what I learned from some of the pilot studies that are done so far, it's really technology specific. Right? So, if it's EVs, you want studies looking at EV response. If it's heat pumps, you want to understand what their potential is, right? And that's actually-- that can be more significant than the particular price design is what technology, what enabling technologies are available.

COMMISSIONER MONAHAN: Sounds like we're leapfrogging your presentation a little bit.

MS. MARSHALL: Yeah.

COMMISSIONER MONAHAN: Okay, we'll stop.

MS. MARSHALL: Okay, let's go to San Diego. Okay, and I'll just-- boy, San Diego had a confluence of factors a few years ago. They had a delayed GRC, and that leads to what they call an exaggerated test year bump. They had, I think an error procurement cost triggers, some balancing account shortfalls, a combination of transmission cost increase. So, they have really had the largest rate increase.

And then in the residential sector, they have the largest proportion of residential behind the meter, so that really exacerbates the cost shift from them. So that might get mitigated going forward a bit. Okay, so now we'll move on to the procurement-- revenue procurement side of things.

Next slide.

Oh, I forgot. SMUD, our two largest publicly owned utilities, not to leave them out, SMUD and LADWP. So, the increases on here from LADWP represent their last five-year rate actions. Since then, they have some kind of automatic cost adjustments to allow them to meet revenue targets. They have not yet announced a rate action plan to meet the LA 100 policy that they've adopted. But when they do that, we would expect at least similar growth rate going forward.

SMUD, as it usually does, chugging along at around three to four percent there. Although they did recently propose a little over five percent rate increases for 24 and 25, and that's both to meet their decarbonization plan, and also responding to the higher power costs, higher inflation, higher interest rate environment. A lot of POUs are in that position as well.

So, next slide.

Okay. So, to forecast the total procurement revenue requirements, we're starting with information provided by the utilities, the larger and any public utility CCAs or ESPs that are over 200 megawatts a year. So, for their long-term contracts and their utility owned resources for things like hydro and renewables, we're taking those costs as given. And then market purchases are valued using the staff energy and capacity price. And then if there's a residual net short need to meet the total demand forecast, we're also going to use the staff energy and capacity prices to value that.

For renewable resources, use the NREL annual technology baseline levelized cost, and you know in the past that's just been incremental wind and solar to meet policy targets. And this year it’d be looking up the cost of the offshore wind as well.

So, one of the key inputs to all of this is the-- next slide, please.

Our wholesale price of energy. So, this comes out of the PLEXOS model that Richard was just describing. So, they do produce 8760 for each-- prices for each balancing authority, and then within CAISO for each tack. What I'm showing here is the average annual price at the CAISO level. And for comparison there I have the CAISO’s actual reported average annual wholesale cost, so comparable value there.

And you'll notice, yes, there's a big discrepancy there between the ‘22 actual and our starting point of our forecast. And that of course is the extremely high gas prices at the-- in 2022. The CAISO Department of Market Monitoring estimates though that if you normalize the natural gas prices back to 2018 levels, we would've had average prices in 2022 of about $45. So that's about $5 less than our starting point. So, it looks a little more reasonable in that light.

So forecast has real prices increasing about 3 percent a year higher than the series I was using for last year's forecast, which we didn't have our own PLEXOS results at that time. So, I was using our burner tip price, which is similar to the one we're using now, but a heat rate curve from some modeling at the PUC, we're using an earlier vintage of CEC demand forecast. So that heat rate curve was improving, things were getting more efficient over time. But now with a higher load forecast, we have more less efficient higher cost units running. So that's pushing prices up over time.

And if we go to the next slide, we can see what's going on a little better at the hourly level. So, this is a snapshot of the annual peak demand, which is in September over time. And you can see while the midday and even the morning prices are not increasing nearly as much, it's the afternoon peak hours where costs are really, really increasing. So, when utilities are doing rate design, periodically they will do a look ahead at power costs and look at it at an hourly level to evaluate whether they need to change their rate design.

For example, should the time of use periods change? So, this is something we want to pay attention to because we don't want to have a mismatch between our load modeling as we're adding EVs and building decarbonization, and what our time of use assumptions versus what that's doing to the system load shape.

So, in this snapshot, and here we're only going to 2035, it doesn't look like the hours of the peak period are really changing, but the peak to off peak ratio is dramatically increasing, right? Which suggests increased value to load shift and, you know, a steeper price differential on some of those rate designs. But this is something we'll want to pay attention to once we get this forecast done, and the PLEXOS team can run a forecast for 2040. We'll kind want to keep evaluating this to see if we want to change the time of use assumptions in our EV model, for example.

So, next slide.

The other price series we need to forecast is capacity costs. And as this table shows, they have really maybe not quite doubled, but pretty close. These are data compiled by the PUC on actual RA market transactions. So, what I'm proposing for this forecast is to hold that 2023 value constant in real terms. And even though these are historically high capacity prices and we're bringing more resources online in California, we also have the Western Resource Adequacy Program coming into play. So, it suggests we're going to continue to have really tight capacity conditions and a lot of demand for available capacity.

Okay, next slide.

The last part of the procurement cost you want to talk about—yes?

VICE CHAIR GUNDA: Sorry, this might be just outside the scope of this presentation. But for RA resources, imports, how much of the resource imports are usually coming on from transmission? Do we know? Have a sense?

MS. MARSHALL: I don't know. My recollection is for having firm transition as important a part of being RA capacity, but I don't know that percentage.

VICE CHAIR GUNDA: Okay, thanks.

MS. MARSHALL: We could look into that. So, the last price I want to talk about is the price for our GHG allowances under the cap-and-trade program. So electric generation, gas fire generation is covered by our carb cap and trade program. So as Richard mentioned, when they're modeling electric generation in California, they're including that as part of the cost. Our price forecast for this is also used by production cost modelers throughout the WECC.

We've had this same program structure in place since 2013 with gradually declining allowances. And then there is a price containment reserve so that as prices hit a certain level, then more allowances become available. So, CARB has been all clear through the scoping plan that they would be revisiting cap and trade to make it quote unquote do more. And just last month they began-- they started a pre-rulemaking process to implement that. They don't have a specific proposal yet, but what they were very clear on is they'll be reducing the supply of allowances from 2025 to 2030. So that will have a pretty immediate impact. They're not really looking to restructure the larger program at this time because they're expecting some legislative direction on what it ought to look like post 2030. So ultimately, they'll be doing an impact evaluation that then we can use in building a forecast. We don't have that yet. Let's go to the next slide.

What we have seen is, since they initiated this process, is the prices on the commodity markets, like if they're traded on ice, have bumped up noticeably about $5. So now those commodity markets, those are mostly private investors. They're not the compliance entities who buy most of their-- do both of their buying and selling on the auction, but there's an auction tomorrow. So very helpful.

And I typically do two forecasts a year, so preliminary in August and then a final in January. So, what I'm proposing to do is for the preliminary is just benchmark the starting point of this forecast to whatever we see as current prices, and we'll take into account the auction results tomorrow. And I'm accelerating the price forecast to reach the Tier 1 price containment reserve in 2030 instead of 2035. And when it hits that tier price, then as it approaches it, CARB will make more allowances available. So, it's a natural kind of slowing point for price increases. And then we'll monitor the CARB proceeding and as more proposals or analysis comes out of that, then we'll update that, do a probably more extensive update at some point.

Okay, so that's the end of the procurement cost side. I have one more slide. Next slide. I think? Yes.

And I'm giving kind of short shrift to the other revenue requirements, which are over 50 percent. We're receiving projected recent and projected revenue requirements from the IOUs, public utilities, many CCAs. And using that data, we evaluate what their escalation assumptions are. But the most important component, particularly for this cycle is that all three IOUs have pending rate cases with really significant proposed results. If those were adopted in full as the IOUs proposed them, we'd see again, more 10 percent annual rate increases for PG&E and San Diego, SCE's might be a little less.

So, we don't want to include that in the forecast because they never get the full ask, right? So, what we'll do is look at the party positions, office of public advocates, TURN, maybe we'll have their recommendations, and construct sort of a mid-case between the full request and, you know, where the parties are and taking into account some of the recent trends in GRC decisions to try to get something close to an expected outcome.

And that's my last slide. We do expect to present the rate forecast actual results at a DAWG in September.

VICE CHAIR GUNDA: Lynn, just on the distribution side, the report that PUC put out with, I think, Kevala?

MS. MARSHALL: Yes.

VICE CHAIR GUNDA: Is that-- what do you anticipate?

MS. MARSHALL: Well, okay, so in the past I've tried to use marginal costs to estimate an incremental cost of all supporting increased low growth. It's probably underestimating those costs and it's not really applicable to with adding all of these EVs. So the Kevala study I think at this point is not because it's not really aligned with our demand forecast. So, I don't think there's results there I can use yet. Also the public advocates did release kind of a summary of something they're working on that's more aligned with our forecast, and they indicated results would be available in August. If they release that in August and they put it in the, let's see there's a load flexibility docket, and parties can comment it. That may be something I could use as an increment to the distribution revenue requirements. So, I'll be looking for that.

VICE CHAIR GUNDA: Lynn, just kind of -- this is more of an educational question. Like what's the elasticity that you actually see with prices and demand? Is it really there? I mean, is it like significant? I mean, I'm just kind of thinking through, right? So, moving forward, just from a policy standpoint, we are kind of planning for a reliable, affordable system and clean system, and we are electrifying a lot of load.

Are we going to be in a situation where the energy costs are going to just increase because there is some minimum level of energy people have to use for their basic needs? Or there's a lot of cushion? You know, I mean, I just feel like we are pushing on all fronts. And we are thinking from your of view, how do you see this playing out?

MS. MARSHALL: Well, the loads that we're adding, EVs, are probably the most flexible load. So, you're right, there are a lot of customers, low usage customers who have very little they can do, right? But that's not where the load growth is. Right? It's EVs which have a lot of load shift potential.

And it'd be very interesting to see what happens with the heat pump studies, because it does seem like that's another one where you have a lot of load shift potential. And what really will matter there is enabling technology so you can automate it. Right? That will be key so that people aren't, you're not expecting people to take that action themselves.

COMMISSIONER MONAHAN: I mean that actually is a really good, I think, observation, is that it's those enabling technologies that are really going to unlock this potential for shift of demand. And without them, if you're relying on individual consumers to make individual decisions, that's a tough sell.

VICE CHAIR GUNDA: Like the smart thermostat experiment. I'm not sure how many smart thermostats actually work, but. One is automation and then how do we comply and keep them actually--

COMMISSIONER MONAHAN: Right, I mean it's the engagement with the automakers, honestly. I think it's that it’s not just this device that you purchase, but it's that integration with the vehicle where the vehicle is saying, if you want to save money, do this.

VICE CHAIR GUNDA: And continuously kind of monitored to make sure it's adjusting that, right? And we're not opting out or doing something else.

Thank you so much. This is so informative. I mean personally, every time I hear you speak, Lynn, I learn something new and I try to ask 10 questions because I'm just, oh, the sparks are finally going off in my head. So, thank you so much. Yeah.

COMMISSIONSER MONAHAN: And can I too, Lynn, this is great. But just this idea of, I feel like the more transparent we can be in the IEPR about-- and maybe in appendices, I'm not sure we want to keep the report a manageable size. But you know how-- what assumptions we're using around the flexibility of demand and where we're trying to get more information. And I just feel like that is, so much of our work going forward is optimizing that. And we're, you know, I wouldn't say we're early, we're in the middle of it. But just being transparent about what we know and what we don't know. I think it's really helpful.

MS. MARSHALL: Actually, the electrification staff, Ingrid's team, she's having regular meetings with PUC to talk about what's happening with like some of the pilot studies and what we need to do to be thinking ahead to incorporate it in the forecast.

COMMISSIONER MONAHAN: I think that's it for me. Vice Chair? Alright, I'll pass it back to Heidi.

MS. JAVANBAKHT: And we don't have any questions online. Are there any questions in the room? No questions. So, Stephanie, we can move on to the public comment period.

MS. BAILEY: Hello again. Okay, so just a quick reminder. We do welcome written comments after the workshop by close of day on September 1st. And for instructions on how to provide written comments, please see the notice for this workshop, which is posted on the CEC's website. So now it's time to turn to public comments. One person per organization may comment, and comments are limited to three minutes per speaker. We'll start with those participating in person and I will turn it over to Heidi to see if we have any commenters on her end.

MS. JAVANBAKHT: Yes, we do have one person in the room.

MR. MCCRAE: Thanks. Good afternoon. My name is Tim McCrae. I'm the Senior Vice President for Sustainable Growth at the Silicon Valley Leadership Group, and SBLG represents hundreds of the most respected employers in Silicon Valley. SBLG notes that energy demand is already forecast to significantly increase as we meet California's electrified transportation and building decarbonization goals. However, we believe that projected energy demand is actually under forecast.

We recognize that demand forecasting has been modified to include building and fleet electrification. However, data center demand, which is another primary driver of load growth, has not been included in the revision to demand forecasting in the way that we suggest. I'll get to how we suggest that.

Under forecasting demand means that we under forecast the need to add infrastructure as well. The delay in forecasting because of the need for infrastructure and additions as a result of the under forecast in demand is particularly concerning because of the incredible lead time it takes to construct new facilities like transmission. Without adequate transmission to deliver energy to load growth centers from the areas where it's generated means that we have islands of scarcity within California that come with reliability and pricing escalation concerns.

The CEC includes projected load for data centers that have signed agreements with their local utility. However, there are many planned data centers that are prior to this stage that the state has no record of expecting, and these loads anticipate being fully served within the next five years, two to three times as fast as the planning life cycle of additional transmission.

While data centers are one example, further economic development will increase electricity demand at a greater rate than it has in the past due to building electrification policies and transition to more high-tech energy incentive technologies. Therefore, we recommend that the Energy Commission complete a study to evaluate the state's future and economic development and electricity demand to inform future consumer energy demand forecasts. I asked some questions about geographic specificity, and we think that in particular in Silicon Valley, there's going to be a lot more data centers and that was where the thrust of those questions were coming from.

SBLG has supported the state's move to zero carbon generation goals. Broadly speaking, California will require significantly more generation and transmission to make zero carbon goals a reality to serve the state's climate and economic competitiveness goals. We ask to improve your consumer energy demand forecasting in these ways. Thank you.

COMMISSIONER MONAHAN: Tim, have you submitted that in writing already to the docket?

MR. MCRAE: I have not, but I'd be happy to do so.

COMMISSIONER MONAHAN: Yeah, that'd be great.

MS. JAVANBAKHT: And Stephanie, that's all for the in-person comments.

MS. BAILEY: Great, thank you so much, Heidi. So, we're going to go ahead and move on to those that are participating remotely. So, if you're using the online Zoom platform, you can use the raise-hand feature to let us know that you'd like to comment and we will call on you and open your line to make comments. For those on the phone, you can dial star-nine to raise your hand and star-six to mute or unmute your phone line or we can unmute you from our end.

Okay, so I see two raised hands right now. Claire Broome, you should be able to speak. If you unmute on your end, you can go ahead and begin.

MS. BROOME: Thanks. Can you hear me?

MS. BAILEY: Yes. And actually, Claire, do you mind spelling your name and any affiliation for the record? Thank you.

MS. BROOME: Sure. Claire, C-L-A-I-R-E, Broome, B-R-O-O-M-E, And I'm commenting on behalf of 350 Bay Area. We are an environmental organization with a reach of 22,000 members, and we also comment from a rate payer perspective. So, thank you very much for a very informative afternoon, and I understand what you're trying to do is really complicated. However, I was quite distressed by the inability to consider solar resources on the distribution grid as we saw in my exchange with Richard Jensen.

So, Lynn Marshall showed us that electricity rates by the IOUs are skyrocketing. Yes, wildfire mitigation is part of that, but the white paper from the CPUC, and maybe the Energy Commission a couple of years ago, showed that the major contributors are transmission spending, distribution infrastructure spending, and wildfire mitigation. And they project that those are the major drivers for accelerating electricity rates.

That's why 350 Bay Area strongly urges in this IEPR that the Energy Commission differentiate between PV generation and storage on the distribution grid from PV generation and storage that requires transmission. That energy for the same megawatt of capacity is at least three to seven cents per kilowatt hour cheaper when it's available on the distribution grid close to the load. I'm talking about in front of the meter wholesale, I'm not talking about behind the meter. As I mentioned in my question, the Lawrence National Laboratory now differentiates distribution grid PV from utility scale requiring transmission. And I would urge the Energy Commission to do the same.

So, the other reason that that's really important is it also promotes resiliency. For your SB 100, you anticipate the need for a tripling of photovoltaic capacity to meet California's goals. And I would urge you that a large part of that solar could be on the distribution grid on brownfields, on highway right of ways, and that that will save ratepayers money as well as saving our environment. It is wonderful to hear Vice Chair Gunda and Commissioner Monahan looking at load flexibility. That's also an essential part of this. Thank you so much for what you're doing.

MS. BAILEY: Okay, thank you Claire. I do see one more hand. Mark Roest, I'm going to unmute your line and you can unmute on your end. And again, please state your name and spell your name and affiliation for the record. Thank you.

MR. ROEST: Hello, my name is Mark Roest, R-O-E-S-T. I am Director of Marketing and International Development with Sustainable Energy Inc. And we are a ceramic semiconductor, fired ceramic semiconductor technology startup with breakthroughs in solar, wind, batteries, neodymium replacements, wheel motors and things like that. All based on that same technology.

Building on what Claire was just saying, the the way to block or reduce the requirement for, undo the need for, those increases in rates from PG&E and the transmission grid and even on the distribution grid is behind the meter distributed generation and storage. And that is going to be much less costly than it is today, relatively within a year or two.

And it's also going to be more effective. So solar instead of 18 to 23 percent efficiency will probably reach 40 to 50 percent efficiency or more in the next year or two, and that's reaching production without the supply chain costs, without the production costs, you know, far lower cost.

Battery storage is headed for three to five kilowatt hours per kilogram instead of today's half a kilowatt hour per kilogram. And also, both of them using simple raw materials, no supply chain choke points, and much lower costs of production factories.

So, with those and with putting up canopies over both parking and driveways to augment rooftop solar to be able to cover the needs of both buildings and all the vehicles associated with them, will make it possible for PG&E to actually be just a service organization maintaining balance in the grid rather than the supplier of choice.

And so, PG&E won't need the transmission if the load goes away because the public switches to self-use of its own owned solar battery energy management systems, which will then be paid for from the savings with financing. And then will reduce the cost of living for those people and the cost of doing business for those people who have them, and free up money for other uses in the economy. I think that's it. If you have any questions or-- I would like to discuss all this further in depth offline.

MS. BAILEY: Great. Thank you so much, Mark. Seeing no other raised hands, I guess that will conclude comments for us today. And one last reminder that written comments are due by close of business on September 1st. And with that I will turn it back over to Commissioner Monahan for any closing remarks.

VICE CHAIR GUNDA: I just wanted to comment on a couple things. So, to-- I think to that forecasting group, what Tim just mentioned, right, from Silicon Valley group on being able to think about the data center growth. I mean, I know we've been making a lot of improvements there, connecting directly with, I think, Silicon Valley Energy. I'm forgetting which one it's.

But the other element I just wanted to kind of flag is how do we think about port electrification? Like large scale port electrification? That’s something that is a pretty huge push right now out there. It may suddenly manifest you know, year after year.

And the second one is the ag. Ag electrification, especially with the, I think Heidi, you and I communicated on the ag front, we had a number of ag consumer associations reaching out about some of the CARB requirements and the electrification requirements. So, wanted to just kind of think through what the ag consumer groups were saying was very similar to what Tim just mentioned, which is they're having struggle with forecasting themselves what their electrification pathway is.

And in discussions with the utilities, the utilities are requesting that they come up with that.

And so, it'll be helpful for us to maybe facilitate a conversation and think about, you know, how does that affect future electric load growth just on those two sectors. Thanks. Wonderful presentations today. Thank you.

COMMISSIONER MONAHAN: Yeah, just building on that comment, my advisor, Ben Wender, who's here today, and I have been really intrigued by the forecast in terms of the peak demand and how much it has shifted over the past five years. I mean, it's pretty transformational. It's not just transportation electrification as I have learned, but you know other components too about why we are expecting peak load to be increased.

And as we consider what the possibility of port electrification is, I mean they do have really ambitious plans. It's not the same as a CARB regulation, but CARB is passing regulations on them as well. And they're-- you know, we're going to have to struggle with some of the issues of is this going to be a battery? Is this going to be electric vehicle? Is it going to be a plugin? Is it going to be hydrogen? What is it going to be? But we see this trend writ large that zero emission is the future of at least transportation.

And this is a global transition that's happening. It's not just California. So how do we build in our forecast to be, I dunno if the word is more ambitious, but just recognize this trend is happening. So how do we make sure we're planning for it appropriately?

And it's challenging and exciting and, you know, to think about communities that are not burdened by diesel pollution, that have clean air, look up and see blue sky. I mean that's a huge motivator for why this transition is happening. And you all are at the center of a lot of this work to make sure that we're ready for the electrification that's going to happen. We know it's going to happen. How much I think is the question.

So, I really like what the Vice Chair said about thinking-- and not this year maybe, but maybe just sort of putting a placeholder in that port electrification as the nearer term opportunity, I think ag electrification is definitely on the horizon as well, but that will be more economically driven decision-making, versus regulatory and community-based pressure on ports to get cleaner.

So that's just the exciting transitions that are happening in this world of forecasting that you guys are in the middle of. So, thank you for these really helpful presentations and for educating me, the newbie in this world. And I also want to thank the IEPR team. Heather Raitt wasn't here today and you guys did a bang up job. I think Stephanie on the phone. We had Denise and Raquel and the whole team, just making sure that this went smoothly, and our IT folks as well, despite the fact that we're in a tiny hot room. I dunno if anybody else is really hot, but I am. Maybe next time we could get a fan. But I just really appreciate everybody's work on this. And I think the Vice Chair has one more thing to say. What a surprise.

VICE CHAIR GUNDA: I know, I just wanted to have the last word.

(Laughter)

I think that what you just said though, in terms of the electrification load, I think for transportation, you know, we are beginning to have that scoping plan scenario baked into the transportation electrification. I think the one challenge we will have as a forecasting team, which I think you're beginning to solve for, is how do we both be reasonable to occur, but then kind of help with long lead time delays? Right.

So, the biggest issue we have on, I think, in the forecasting is once we begin to see an electrification take off, and then if we wait too late to basically bake that in once, you know, to have some historical information, we might not have enough time to react on the procurement side and interconnections. I think that's the dilemma. I think same thing that the utilities have raised with us on substation upgrades and such. So, I think it'll be really helpful, especially with the ports, because it's going to be such a huge load suddenly in load pockets, you know, how to kind of, pre-plan those big uptakes. But you can have the last word. I'll stop there.

COMMISSIONER MONAHAN: Well, I just want to say this meeting is adjourned just to have the last word. Or maybe I'm not allowed to say that. I can? All right. I'm saying it. We are adjourned.

(Whereupon the meeting was adjourned at 3:43 p.m.)

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Martha L. Nelson

MARTHA L. NELSON,

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