DOCKETED	
Docket Number:	21-IEPR-03
Project Title:	Electricity and Natural Gas Demand Forecast
TN #:	240010
Document Title:	TRANSCRIPT 8-5-21 Session 2 - IEPR Commissioner Workshop on Data Inputs and Assumptions for 2021 IEPR Modeling and Forecasting A
Description:	TRANSCRIPT 8-5-21 Session 2 of 2 - IEPR Commissioner Workshop on Data Inputs and Assumptions for 2021 IEPR Modeling and Forecasting Activities Forecast Modeling Inputs and Analysis - Forecast Modeling Inputs and Analysis
Filer:	Raquel Kravitz
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	10/7/2021 5:10:32 PM
Docketed Date:	10/7/2021

STATE OF CALIFORNIA

CALIFORNIA ENERGY COMMISSION

In the matter of,	) Docket No. 21-IEPR-03
	)
2021 Integrated Energy Policy	)
Report (2021 IEPR)	) Re: Data Inputs and
	) Assumptions for 2021
	) IEPR Modeling and
	) Forecasting Activities

IEPR COMMISSIONER WORKSHOP ON DATA INPUTS AND

ASSUMPTIONS FOR 2021 IEPR MODELING AND

FORECASTING ACTIVITIES

FORECAST MODELING INPUTS AND ANALYSIS

REMOTE ACCESS ONLY

THURSDAY, AUGUST 5, 2021

SESSION 2 OF 2: Forecast Modeling Inputs and Analysis

2:00 P.M.

Reported By:
Martha Nelson, CERT. 00367

APPEARANCES

Commissioners Present

J. Andrew McAllister, IEPR Lead Commissioner

Siva Gunda

Patty Monahan

Staff Present

Heather Raitt, Program Manager

Raquel Kravitz, IEPR Team

Jesse Gage

Annis Bahreinian

Bob McBride

Hazel Aragon

Paul Deaver

Lynn Marshall

Matt Coldwell, Demand Analysis Office

Public Comment Moderator

Dorothy Murimi, Public Advisor's Office

Public Comment

INDEX

P R O C E E D I N G S

AUGUST 5, 2021 2:00 P.M.

MS. RAITT: All right, I will go ahead and start the opening remarks. So, good afternoon. Welcome to today's 2021 IEPR Commissioner Workshop on Electricity and Natural Gas Forecast, Inputs and Assumptions.

I'm Heather Raitt, the Program Manager for the Integrated Energy Policy Report, or the IEPR for short.

This workshop is being held remotely consistent with Executive Order N-08-21 to continue to help California respond to, recover from, and mitigate the impacts of the COVID-19 pandemic. The public can participate in the workshop consistent with the direction in the executive order.

This is the afternoon and final session of this workshop.

To follow along with the discussion, the schedule and presentations are available on the CEC's website.

All IEPR workshops are recorded and the recording will be linked to the CEC's website shortly following this afternoon. And then a written transcript will be available in about a month.

Attendees have the opportunity to participate today in a few different ways. You may ask questions or

up vote questions submitted to others for the Zoom's Q&A feature. Or, you can make comments during the public comment period at the end of the afternoon. Or, submit written comments following the instructions on the meeting notice. And written comments are due August 19th.

And with that I'm pleased to turn it over to Commissioner Andrew McAllister. Thank you.

COMMISSIONER MCALLISTER: Thank you, Heather. Nice job this morning. I really want to commend the IEPR team. As usual, just a great level of professionalism in marshaling all the inputs on these workshops. And this is a key one today.

This morning we heard about the evolution of the energy demand assessments, and then went through the common case imposed and the assumptions behind the various forecast. And then, got into some of the demand modifiers, including additional achievable energy efficiency, and the new item of Additional Achievable Fuel Substitutions.

And so this afternoon we're going to continue along those items and include -- and talk about the transportation forecast, inputs and assumptions, and some of the production cost modeling that's behind the forecast as well. And then, talk about the retail

electricity rates which is, I think, in more top of mind, certainly, than in past forecasts, and at least as important as always. So, looking forward to that.

So, with that I'll pass the mic to my colleagues on the dias, Commissioner Gunda and Commissioner Monahan.

COMMISSIONER GUNDA: Thank you, Commissioner McAllister. Echo your comments, I think the morning session was excellent. I think it was really informative on setting up the trends. And thankful to you and Commissioner Monahan for raising some important things to consider as we evolve the forecasting. So, I've been taking notes. So, look forward to the afternoon session. Thank you.

COMMISSIONER MONAHAN: Well, I'm particularly interested, as you might guess, in the first part of the afternoon transportation. With the governor setting a very aggressive executive order of basically everything in transportation mode, whether its on-road or off-road, be electric or zero emission by -- within the next 15 to 25 years. Very, you know, aggressive. Although, as we've seen especially battery price declines over the last decade, there's just a lot of room for optimism in terms of these vehicles being cheaper than conventional vehicles.

So, just a warning, I probably won't be able to stay for the full day. I'm actually in New York today, and so on vacation, but I couldn't miss the IEPR workshops because they're a draw. So, thanks for the IEPR team and EAD, thanks to my fellow Commissioners for making this a really informative and helpful session. And we're missing some of my family today.

COMMISSIONER MCALLISTER: Well, thank you for your dedication. I did not know that. So, that means a lot. But yeah, certainly.

COMMISSIONER GUNDA: Absolutely. Thank you, Commissioner Monahan, that's awesome. Thank you so much.

COMMISSIONER MCALLISTER: Yeah, well thanks even more for being with us.

Great. Well, so I'll pass the mic back to Heather and we can get started on the transportation forecast.

MS. RAITT: Great. And I just have to echo my thanks to Commissioner Monahan. That's amazing that you're joining us. So, thank you.

Our first presentations from Energy Commission staff are going to be discussing transportation. And so, Jesse Gage is first and he's presenting on the Historic ZEV trends. Followed by Aniss Bahreinian and

Bob McBride, representing on model updates. Jesse is the Lead Analysis for our DMD vehicle registration data in the Energy Commission's Demand Analysis Office.

And so, then I'd just like to suggest that we hold questions until the end of the presentations on transportation.

So, with that I'll go ahead and ask you to take it away, Jesse. Thank you.

MR. GAGE: Thank you. And good afternoon. I am Jesse Gage. And among other things, I am the Commission's primary analyst for the DMV's vehicle registration database. This database is a quarterly snapshot of every new vehicle registered in the State of California.

We use this data to provide the base year light- and heavy-duty vehicle stock forecast inputs for our forecasts. This database also serves as the primary source for our ZEV Stats data portal. You all have heard of ZEV Stats, right? Somehow, I'm hearing a couple of no's through Zoom, so how about we take care of that right now.

Next slide, please. Next one after that. Thank you. We at the CEC have developed what we believe to be the most comprehensive, publicly available dataset regarding zero emission vehicles in California.

If you're doing research regarding sales, population or infrastructure, chances are you can find it here. The majority of source data in this presentation is lifted straight off of ZEV Stats. Second quarter data just showed up on the site Monday, go so ahead and have a peak.

The URL is at the bottom of the slide, but little secret you don't need it. Just type ZEV Stats in your search engine of choice, and it's the first hit.

Now, with that out of the way, let's get on with the show. The next slide, please.

Today we're going to be taking a top side view of ZEV population and sales, both present and historic back to 2013. But first, here are the headlines. Battery electric and plug-in hybrid-electric vehicles are fast becoming a hot item in California. We are easily on track to break our 2018 of ZEV sales by year's end. And there's a good chance that one out of every ten light-duty vehicles will be battery or plug-in hybrid.

We'll also take a look at where we're at regarding the targets laid out in active executive orders, a quick dive into the largest of ZEVs, spoiler alert it's Tesla, and show how the catalogue of ZEV models are beginning to look more like the light-duty

fleet as a whole.

The next slide, please. The early years of the ZEV market saw steady, yet somewhat measured growth, with battery electric and PHEVs running neck and neck. In 2018, however, Tesla released the much awaited, much hyped, and much pre-ordered Model 3, which has become the highest selling ZEV model to date. All electric vehicles solidly outsold PHEVs that year and haven't looked back.

2019 saw a slight decline in sales for vehicles in general, both internal combustion and alt fuel. Sales then fall sharply in 2020 because -- because 2020. But Tesla's new Model Y sold a ton, which kept ZEV totals relatively flat.

But now, in 2021, well, we nearly hit 2020's yearly total by June, and this is without a Tesla model to carry the load, or at least a new one.

Second half yearly sales are usually stronger than the first half, so end-of-year totals could easily hit 200,000 or maybe even a quarter million by year's end.

The next slide, please. There are three major executive orders looking to shape zero emission vehicle sales. Former Governor Jerry Brown signed Executive Order B-16-2021, in 2016, which called for one and a

half million ZEVs on the road by 2025. Governor Brown then set a significantly more ambitious goal two years later, this time it is targeting 5 million ZEVs by 2030 as part of EOB-48-18.

You can see here that the 2025 target is easily within our grasp. With ZEV sales growing the way they are, I'd say it would be tough not to make that goal. Five million by 2030, however, well, that's going to be a climb. And it's plain to see here that so-called business as usual is not going to get us there.

Last year, our current governor, Gavin Newsom, pulled out the big gun, Executive Order N-79-20, with the goal of eliminating light-duty ICE sales entirely by 2035. Now, that EO doesn't come with a hard target of how many ZEVs need to be sold why when, which is why I've not placed it in this chart. But just in case 5 million wasn't ambitious enough for you, ARB's Mobile Source Strategy suggests we'll have 7.8 million ZEVs by 2030, if we're to meet that EO.

As far as what here at the Commission think N-79-20 will mean for sales in 2030 or 2035, well, that's why we do this forecast, so stay tuned.

And before we go to the next slide, I should give a mention to the Biden administration's new target, published this morning, where half of all ZEV sales will

be -- or half of all light-duty sales will be ZEV by 2030. If that goes through, I did some napkin math and that will probably mean probably about a million, million and a half new light-duty vehicles on the year every year between 2030 and 2035, when 79-20 takes effect.

So, with that, next slide, please. We and the public talk a lot about Tesla, to the point where for years now they've become almost synonymous with electric vehicles, and even alt fuel in general. What's interesting to note, however, until the Model 3 hit that wasn't really the case. The Model S came in second that year, sandwiched between Chevy's Volt, with a V, and Bolt with a B, respectively. You also had the Prius Prime Model X and the Fiat 500e moving more than 5,000 units each.

Clearly, the Model 3 has been dominant since its introduction, but only in 2020 did Tesla gain a majority of the ZEV market, and even then just barely.

Now what, you may ask, are the hot models selling this year? Great question and not just because I asked it.

Let's take a look, the next slide, please. If we look at the top ten sellers for this list on the left here, we of course see Models Y and 3 at the top, with

over 25,000 units moving each, with more than double the sales of runner's up Chevy Volts and Toyota Prius Prime, both with sales a bit over 10,000. I will note that the Bolt, however, is having a pretty strong year this year, compared to the last year despite being in the same generation.

After that you have several in the 2,000 unit range, but I -- call this a hunch, but I think Ford's new Mustang Mach-E will probably be the one to watch on this list as it's got quite a bit of buzz on the internet.

On the right is the all time best seller. No surprise that the Model 3 is tops here, with Tesla's S, Y and X models all in the mix.

The old PHEV Volt is still second all time. And the list is rounded out by familiar faces in the LEAF, Prius Prime, Fusion Energi, and the 500e.

Next slide, please. All right, enough talk about how many ZEVs have been sold. Let's look a little bit about who's buying them. We broke out our light-duty models into four sectors, namely personal, commercial, government and rental fleets. And by the latter, I mean in the traditional sense where, you know, you get off your plane, grab your luggage, your Ford Focus for the weekend, that sort of thing. Not so much

the TNCs.

Personal vehicles, not surprisingly, make up the vast majority of the light-duty fleet. And commercial vehicles are most of the rest, while government and rental vehicles are only about 1 percent each.

On the right you will notice that while the personal and commercial fleets have about the same amount of ZEV penetration, the government sector has almost more than -- well, more than twice the ZEV penetration as the personal and commercial fleets, while rental has hardly any at all.

It's not too hard to imagine why government would have so many more ZEVs. In theory, this is more of a policy decision rather than a market decision you would see in the personal and commercial sectors. Although, there still are a couple barriers to entry, even with government.

First of all, it might be -- I'm not a policy wonk (phonetic), so I don't know how top down the state can make it, but only about 7 or 8 percent of government vehicles are state owned. The rest are county and local, for the most part.

Also, about two-thirds of those vehicles are pickups and vans, which right now don't have much, if any, representation in the ZEV market.

And then there's rental, where I'm looking for a good reason why there's so few and I can't find it. I think it's a good question. I'll note that as bad as this looks, I think the reality might be even worse because almost all the rentals, ZEV rentals on the road are from a single purchase of Model S's, back in 2018.

The next slide, please. Next slide. Thank you.

One trend I've noticed over the years is that after several years of concentrating on the passenger car market, the ZEV industry is diversifying significantly. It's no surprise that SUVs have, to a great extent, replaced sedans in the broader light-duty market, with 44 percent of available ICE models, as compared to 34 percent for cars.

The ZEV marketplace now is starting to match this much closer, with about an even mix of passenger cars and SUVs. We still need some pickup trucks, which I mentioned last slide, which is why the Ford F-150 Lightening already has somewhere north of 120,000 preorders nationwide, ahead of its projected spring 2022 launch.

The next slide, please. One area where manufacturers may be missing the mark is when it comes to PHEVs and full electrics. We saw earlier that the parity in sales between the two was soundly broken in

2018, but that hasn't stopped manufacturers from continuing to design more PHEV models than full electric.

I can't say if this reflects lag in development time, or traditional manufacturers just testing the waters when it comes to consumer range anxiety, be it what you will. But a more deliberate way from internal combustion entirely would be quite welcome from a GHG perspective.

The next slide, please. Finally, I've said an awful lot today about battery electric and plug-in electric vehicles, but as someone who just got himself a hydrogen fuel cell vehicle, I'd be remiss if I didn't shed a little light on the dark horse in the race.

The nascent FCVE industry hit a bit of a milestone last quarter as the 10,000th fuel cell vehicle was sold in California, or more likely leased as the free fuel card that comes with FCVEs is only good for the three years, whether or not you lease or buy. So, I think most people are leasing them.

When it comes to available FCVE models, it's unfortunately pretty slim pickings. Most popular by far is the Toyota Mirai, which comprises about 80 percent of FCVE sales. It's been around since 2015 and consistently has sold about 1,500 units per year until

it was pulled in 2020 for a redesign, which came out at the end of the year.

Honda's Clarity FCVE, meanwhile, has been nearly all the rest, but will no longer as it's being discontinued with production stopping this month.

And then at the bottom you've got my ride, the Hyundai Nexo, which is the sole SUV of the bunch. I got mine about two weeks ago and I know I can't exactly give a professional endorsement here, but I'll definitely vouch for it on a personal level. It drives quiet, and smooth, and it's got cruise control but it kind of feels like witchcraft. It loves hills. I love taking it on drives. And I'm pretty sure my riding partner there agrees.

The next slide, please. And that's the news as far as ZEV goes. I believe we are taking questions at the end of the session, so unless there are any comments I think we can pass it over to Aniss and Bob.

MS. RAITT: Great. Thank you, Jesse. Yes, Aniss, go ahead please.

MS. BAHREINIAN: Good afternoon Commissioners and stakeholders. My name is Aniss Bahreinian and I'm going to focus on the model and input updates for the light-duty vehicle forecast.

Next, please. The updates that we're talking

about include different categories. One is the forecasting input and any of the -- well at least two or three of the last IEPRs we have been essentially updating the inputs. But this year, we're also updating the model.

In addition to updates in models and input, we are also updating the light-duty vehicle classes. We have changed the way we are classifying vehicles.

Next, please. The inputs to the light-duty vehicle demand forecasting are many, but here we are going to talk a few key inputs and how they have been updated.

One is the economic and demographic data, and we use a lot of that in forecasting household vehicles, light-duty vehicle demand. We are using macroeconomic forecasts by Moody's, as well as population forecast by Department of Finance that Cary Garcia has already referred to them. But in addition to those, we are also using the 2019 American Community Survey data because we need to have a finer breakdown of the households by income, and other categories that we are going to see later in this presentation.

In addition to economic and demographic data, we also have, obviously, energy prices. And our energy prices are along the same line that are used in other

forecasts, in electricity and natural gas demand forecasts.

And vehicle attribute is a very important input data to our model and it is one that drives the ZEV penetration. And so, it is quite important to update the vehicle attributes. We have updated all of the vehicle attributes, such as vehicle prices, fuel economy, fuel costs, and acceleration, and others.

And we are also updating the technology introduction tables and elimination schedule. Technology introduction schedule identifies which fuels and technologies are being introduced in what year. And that is very important to the forecast of ZEVs for instance.

But it also identifies which vehicles and fuel types are deleted from a specific class of vehicle. For instance, there are a number of classes of flex fuel vehicles, and diesel vehicles, in which there are no longer any production and so we are excluding them from the forecast.

The 2021 forecast also differentiates between luxury and standard vehicle attributes. So, for instance the prices of Model S versus Model 3 are going to be different. This is going to increase the volume of data and computation that we will have for the light-

duty vehicle forecast. Because, essentially, we have most of the classes in light-duty vehicles are offered in both luxury and standard levels.

Light-duty vehicle attribute forecast this year, in 2021, also includes one scenario on the 2035 ICE sales ban. We don't know exactly in which scenario we are going to use it. But as Commissioner Monahan mentioned, more likely it's going to be an aggressive or other scenarios.

The forecasting horizon for light-duty vehicle forecast is 2021 to 2035.

Next please. In addition to updating the inputs, this year we are also re-estimating the models, the light-duty vehicle models. And consumer preferences in the newly estimated models reflect what happened in the California Vehicle Survey. So, it reflects the consumer preferences in the residential and commercial market segments, as captured by 2019 California Vehicle Survey.

The 2021 models differentiate between luxury and standard, and identifies different consumer preferences for luxury versus standard vehicles.

In the 2021 model we also have a higher resolution of income category. We have 10 income categories versus 7 income categories in prior

forecasts. So, we have a finer breakdown of income. Each of these income categories, households in these income categories are further broken down by household size, by the number of workers in the household, and the number of vehicles that they own. All of these are going to add up to 513 household types versus 362 household types in prior forecasts. So, you can clearly see that this is going to increase computational demand on the forecasting software.

On top of that, we have made another change in our models and rebate incentives now have an income criteria. And with this change we are able to be more consistent with current CVRP practice that uses an income criteria in awarding rebates for ZEV vehicles.

Next please. Finally, we have new vehicle classifications. We have now 15 new classes versus 18 legacy classes that we used in the past. The changes that we have made are focused in the red rectangle that you see there, SUV and crossover. What we have done, we have combined SUV and crossover together, rather than having one body type as SUV and another body type as crossover SUV, mostly because consumers essentially consider them the same, and even the manufacturer sometimes present them as the same. Although, they are not exactly the same, but what is important is how do

consumers perceive them.

By combining those categories, we have reduced the formerly 7 categories, into 4 categories. We have kept compact, midsize, and large SUV crossover. And we have added another classification for subcompact SUV. We didn't have this in the past, so now we have a subcompact SUV crossover.

And in the past we also had a heavy light SUV, which was 8,500 to 10,000 GVWR, and we have deleted that one from our SUV classification, because it is no longer being produced.

Now, notice that light-duty vehicles in our forecast are considered anything up to 10,000 gross vehicle weight versus CARB that uses 8,500 as the threshold for LDVs. The reason for it is that our staff analysis of the DMV data shows that these vehicles are used both in the household sector and in the commercial market segment. And so, we have decided that we need to include that class in our light-duty vehicle categories.

I believe NHTSA has the same. They have the 10,000 threshold criteria versus 8,500 criteria that is used by CARB.

Next please. Thank you very much for your attention and I'll be happy to answer any questions that you may have. With this, I'm going to pass it on to Bob

McBride, who is going to talk about medium- and heavy-duty vehicles.

MR. MCBRIDE: Good afternoon Commissioners, stakeholders, and staff, and interested public. I'm Bob McBride. I work on the medium- and heavy-duty truck choice and energy demand forecasts, as well as vehicle movement in general.

The next slide, please. Yeah, here's a grouping of weight classes with pictures of typical vehicles, for your reference, if you haven't seen this before. We make the light and heavy -- light- and medium-duty split at 10,000 pounds gross, or loaded weight, as Aniss explained.

Next slide, please. Today I'll be going over changes we've made in the truck choice and the freight energy demand models, and data since the 2020 forecast. Economic growth trends for our three common electricity demand cases will be refreshed using recent econ demo data from Economy.com.

CARB's Emission Factors Model, EMFAC, truck classes have changed for 2021 to reflect finer grain representation of weight classes. Previously, these could be lumped to our -- to confound us, mostly.

For this reason, we designed our classes to stay comparable with the new EMFAC ones going forward. We

use the California Bias Survey results to allocate freight tons to the new larger set of weight classes, where previously we did this for only interstate and instate Class A tractor trailer classes.

Our consultant, ICF, is referring the truck purchase prices used in the Choice Model, and has mapped fuel economies from EMFAC for the first time to our larger set of fuel types.

The matrix we use to define which combinations of truck class and fuel types exist and when, and when they're likely to be commercialized has changed to keep pace. So, you'll see that.

Battery electric trucks will no longer be restricted in the Choice Model to drive cycles at or under their nominal range, since we now assume a system for en route charging.

We've also updated our representation of intermodal rail and truck. That's containers and truck trailers that go via rail, and the trucks that pick them up or drop them. We use Federal Confidential Rail Way Bill data that's also used for the Caltrans Freight Model to do this.

The next slide, please. Here's our new list of modeled truck classes in rows and our changed roundup of fuel types in columns, just as a reference. Please

don't read this right now. This is analogous to the light-duty technology introduction and elimination schedule Aniss talked about. We've now included a PHEV, but we no longer cover dedicated ethanol or catenary electric, since those simply did never take off. The earlier years of introduction are not intended to be historically accurate, but to set which fuel types should be regarded as fully mature in the Choice Model.

Yellow highlighting shows changes we've made in consultation with ICF this year. And we're still pondering the inclusion of the four cells shown in reddish tan.

Next slide, please. We're using the new EMFAC 2021 data in these four ways. A long-term goal is realized in this version since the EMFAC work embedded data from the 2018 Caltrans modeling, particularly the freight forecasting model they did in 2018.

We're using 2019 as our base year, conveniently the last year of historical data in EMFAC.

Modeling driving, annual miles per truck data by class, by fuel and by vintage was rendered smoother by using fitted equations.

Survival rates from EMFAC are also fitted to colonomial equations, allowing us to represent retirement, as well as imports, and purchases of used

trucks, all within the statewide and South Coast Truck Rules, where they're appropriate.

We worked with ICF to map EMFAC fuel economy data to our larger set of fuel types, supplementing fuels reported in EMFAC using the federal GREET Model, and our existing data from HD Systems.

Next slide, please. Here's a chart showing truck classes in yellow, that we assigned to hauling the freight tons, the commodity freight that's in freight analysis framework.

And in blue, the truck types which are service trucks primarily, but used as needed to haul freight that's left over after the yellow class.

Orange for refuse and dump trucks means a specific commodity group is only allocated to a single truck class. For dump trucks that's rabble, sand, and nonmetallic minerals. Yes, this includes dirt.

The next slide, please. So, thank you for your kind attention. It's time for questions from the virtual dais and public on all of the transportation presentations.

COMMISSIONER GUNDA: I can see Commissioner McAllister might have questions.

MR. MCBRIDE: But he's muted.

COMMISSIONER MCALLISTER: Sorry, sorry. Sorry,

I was double muted again. Sorry about that. Yeah, just thanks for the presentations. I actually want to defer to Commissioner Monahan because I have a lot to learn from her as well, and I think it's appropriate she be on point, if you'd like that, Commissioner Monahan. Thanks.

COMMISSIONER MONAHAN: Well, I first want to thank Jesse, Aniss and Bob for all the work that they have done. You know, I want to start with Jesse and his ZEV data portal. I know that you personally, Jesse, have done a lot of work to clean up the DMV data and that it's yeoman's work. It's really hard. And so, I just want to thank you for that. So, it was great to see your enthusiasm, which was infectious, and actually mirrors mine when it comes to talking about ZEVs and that ZEV data portal. I can't tell you how happy I am about that ZEV data portal. I hope everybody who hasn't gone on is using this opportunity to go onto it because it's very cool.

And Jesse's right, it's the best data that exists out there. I mean it was shocking to me when I started at the Energy Commission, well, at my old job I used to pay for people to get access to Polk data, which is a summary of ZEV data. And I was like, what, California doesn't publish this data? That's crazy.

And then I understood why because it's actually really hard to work with DMV, get the right approvals. You know, so I love that portal. I can't wait for it to continue to expand.

It has school bus data right now. And as Jesse said, they're trying to get medium- and heavy-duty, but it's hard because you have to have a certain number of models before you get assigned a unique code identifier in the DMV database to let you tell that it's zero emission. So, trying to work through that and, hopefully, we can get good data on medium- and heavy-duty vehicles, as well as school buses.

I mean it's kind of shocking me we couldn't get good data on school buses. Which we could get data on the school buses that we funded, but that's just about it.

So, you know, that is going to be our challenge I think for the next several years is to figure out good ways to track where these electric and zero emission vehicles, whether they're fuel cell electric or battery electric. Who's buying them, what they are, Class 6, Class 8, school buses, transit buses. Now that we have all this money for ZEVs in the budget, 1,000 school buses, 1,000 drayage trucks -- 1,125 drayage trucks, I'm sorry, and 1,000 in transit buses, we need a way to

track our progress. So, this data portal is a way that we get to be held accountable.

Yeah, I'm psyched about it, as you can tell.

COMMISSIONER MCALLISTER: We can.

COMMISSIONER MONAHAN: And I do also want to thank Aniss and Bob. There's just been a lot of work done to refine -- I mean consumer choice modeling and the passenger vehicle side, it's hard. Because consumers, as we all know, are whimsical creatures and we have different what we like. Even in the medium- and heavy-duty, sometimes they don't like -- like they like trucks that are kind of old school, that aren't very fuel efficient, because they're cool. They're cooler. So, the whole like what's cool is kind of hard to figure out sometimes.

And I think it will be really interesting -- I'm just making comments and then I'll pass this on. I think it will be really interesting, actually, as we see these vehicles like the Lightening, with the capability to give power back to your homes, and power your power tools, and all of the sudden these vehicles aren't just like mobile devices, but they're also -- they do all these other cool things and we have to figure out how to value those cool things, and quantify what that means in terms of consumer choice preferences.

So, I mean, but the team is like on the cutting edge of a lot of this work. And I think what we're going to do is we're going to be in a state of deep learning over the next several years as these vehicles roll out into the marketplace, and we see what gets adopted and what doesn't.

I mean the manufacturers spend millions of dollars on consumer choice evaluation to figure out what they're going to put in their new model, and they don't get it right all the time.

So, you know, this is hard work and just appreciate this team's openness to like exploring these kind of cutting edge issues when it comes to electrifying both passenger vehicles and trucks.

So, a lot of commentary, not really questions.

COMMISSIONER MCALLISTER: Great, perfect. Go ahead, Commissioner Gunda.

COMMISSIONER GUNDA: Yeah, Commissioner Monahan, thank you. I cannot -- you're really good at showing the enthusiasm. I've been raised kind of like to hold it down. But I'm really glad you went before you because I feel just as enthusiastic. And I don't get to see Aniss, Jesse and Bob as much as I used to a few years ago, and I just want to congratulate them for all the good work, and your leadership, Commissioner Monahan

on kind of raising some key policy questions and directing the team to kind of explore those analyses that can get to those policy questions. So, just thank you for that.

A couple of also acknowledgements I just want to make is, you know, Heidi, I think Matt, and Aleecia have all been kind of working behind the curtain and I just want to thank them as well for their work.

And so, a couple of comments or question, I think that this is a question. And specifically to your presentation, I think slide number 5, so you kind of talked about reclassing the number of buckets. Could you just kind of expand on how that might continue to kind of help us sync with CARB and such, or kind of what are the implications of that in terms of the broader statewide alignment in thinking these analyses?

MS. BAHREINIAN: I think it is essentially going to make it a little bit more real because consumers, in so many ways, are considering SUVs, and crossover SUVs the same. And then, on top of that, as I mentioned, heavy SUVs are not even being manufactured anymore, so they are out of the market.

So, we needed to do this reclassification in order to bring it more to reality, make it a bit more accurate. Because even some of the manufacturers,

themselves, are presenting crossovers as SUVs. Not all of them, but some of them are presenting it as SUVs.

So, we have to get back in the mind of the consumers. That's our job here. And so, we try to make it a bit more realistic when it comes to SUVs and crossover. Hopefully, it is going to increase the accuracy a bit more.

COMMISSIONER GUNDA: That is great. And I want to take the opportunity to thank you for drilling into the details of the modeling for several years.

So, with that I guess one additional question is we've kind of, over the last several years you've been trying to incorporate some incremental improvements on the miles, you know, traveled by each model based on the different analysis. Has there been kind of progress in us being able to just drill down a little bit more into kind of like reality versus kind of the averages?

MS. BAHREINIAN: We do have some survey data on vehicle miles traveled. But the way the models are working right now, as you know, the urban and intercity models are taking on that role of accounting for the vehicle miles traveled for long distance and short distance travel.

We also tried to true up the VMT numbers that we are getting from the surveys by using a dual odometer

reading. That was one of the efforts that we made in creating more accuracy.

Unfortunately, perhaps it was because we didn't have enough incentive, we didn't get as many of the survey participants to take part in that because it was an additional task that we were asking the survey respondents to do. Two months later they either had to look up into their existing records or they had to report the VMT on their vehicle's odometer two months later.

So, we did get some results, but it wasn't as many as we had hoped for. So, perhaps in the next survey we are going to make more advances.

COMMISSIONER GUNDA: Thank you. Thank you Aniss. So, just a closing comment from my end. I think similar to what happened in the morning presentations, the way that Jesse set up the trends is extremely helpful from kind of having -- being able to ask clear policy questions.

And also, Bob, your table on why you're making decisions on not including certain technologies, like try things -- and why, I think that's very, very helpful. And I think being able to -- I just wanted to request the team to develop some sort of a publication material that we could more broadly share with the

agencies, even a summary, a couple-page summary on our high level thinking would be really helpful.

So, with that I'll pass it to Commissioner McAllister.

COMMISSIONER MCALLISTER: Thank you very much.

COMMISSIONER MONAHAN: Oh, and can I just --

COMMISSIONER MCALLISTER: Oh, go ahead.

COMMISSIONER MONAHAN: I'm sorry, can I just make one comment on this just because I think the mileage, there's been a lot of controversy around how many miles are electric vehicles actually driven. And I, too, would just encourage the team to get more current data on that question, especially in the passenger vehicle suite. I think it will be easier to get commercial vehicle data.

But I've seen a lot of conflicting data. I know that in our last survey there was some indication that newer electric vehicles are driven more miles than conventional vehicles and that's a curious finding, one that we, I think, need to explore more deeply about how durable that is given sort of the lack of -- you know, we just didn't have enough respondents to be as definitive as we would like.

So, that's a really foundational question. And I like what Commissioner Gunda was saying, too, about

being more transparent and public about what we were finding, even if what we're finding is preliminary and needs deeper analysis or needs more data to be able to really verify. Because these are such important analytical questions for the broader community that I think we should be bold and transparent in sharing that data.

MS. BAHREINIAN: Certainly.

COMMISSIONER MCALLISTER: Bob, did you want to -- sorry. I think Bob wanted to make a point about, I think, Commissioner Gunda's last question. So, maybe we can close that out, if you still have that point you want to make, Bob.

MR. MCBRIDE: Yes, thanks Commissioner. There's a tie-in here. We've been using, for several years, the smog check data, which is quite detailed and has vehicle mile checkpoints. They do an odometer reading when you get a smog check. So, we have a set by the light-duty and now, increasingly, medium- and heavy-duty vehicle classes of how far each vintage goes a year.

On the electric vehicle side I would say there's some good research at UC Davis, in their ITS section that regularly surveys this. They're contracting with a group at ARB. So, that's what I have.

COMMISSIONER MCALLISTER: Can I maybe just --

so, let me just interject one thing. So, are we -- do we have access to state insurance information or something? Because, you know, nominally, I'm not sure if every -- this applies to every passenger vehicle but, you know, your insurance, you're at least supposed to tell them how many miles you drive roughly, and they ask for an odometer reading every time you, you know, update your insurance. I wonder if we could have access to that information to actually dig into this a little more. Maybe we don't quite have the authority to do that, but I wonder if there's a way to get that.

COMMISSIONER MONAHAN: But it's also classic under-reporting, Commissioner McAllister.

COMMISSIONER MCALLISTER: Yeah. Oh, yeah, no doubt about that.

COMMISSIONER MONAHAN: So, there's a bias on that one.

COMMISSIONER MCALLISTER: There's a bias. Oh, yeah, for sure. Yeah.

MS. BAHREINIAN: So --

COMMISSIONER GUNDA: Commissioner just --

COMMISSIONER MCALLISTER: How about Commissioner Gunda and then, Aniss, you want to respond.

MS. BAHREINIAN: Yeah.

COMMISSIONER MCALLISTER: Go ahead.

COMMISSIONER GUNDA: Yeah, Commissioner, just kind of I think to Commissioner Monahan's comment. I just want to put a plug for our kind of the Energy Insights venue. I think it may be a really good opportunity to just kind of write a two-pager that just kind of flags this workshop and some of the incredible information that Jesse put together.

As I was thinking about having, clipping out Jesse's thing and then just putting it on YouTube, and just saying here you go, that status. I think it might be a helpful way for us to just frame this transparency as Commissioner Monahan was mentioning.

COMMISSIONER MCALLISTER: Yeah, I agree. So, I do have one more questions but, Aniss, did you want to close out the previous topic?

MS. BAHREINIAN: I just wanted to respond to Commissioner Monahan's question on VMP. That's a very good question that you raised. I should add, however, that when we are looking at the survey data, if we are only looking at the households, more or less at the household, and those that have EVs are -- have the same VMT as others.

However, the data that was quoted included also the commercial vehicles. When you add the commercial vehicles, commercial vehicles have higher VMT compared

to residential. And when it comes to the distribution of commercial and residential, ED owners in the surveys, it's almost half and half.

But when you're looking at -- when you're looking at data in the DMV, commercial is about 10 percent of the vehicles. So, we need to make these distinctions and these refinements. Whenever we are using that data, we need to clarify that. And thank you for the point you raised.

COMMISSIONER MCALLISTER: Thank you, Aniss. So, I have one question that it's unrelated to what we talked about so far, and it's for Jesse, primarily.

Does the DMV data give you any insight into the used car market? Like can you do longitudinal, you know, about what a given VIN, what happens to it through its lifetime and, you know, maybe even get some insight on the equity issues?

MR. GAGE: Kind of. Not very easily, however. In theory, you can use it over years to track, you know, where it's moving from year to year. It also has sale price, but along with insurance, you know, it's also one of those things where there's a bias because everybody who sells a vehicle has an interest in lowballing it.

It's something I haven't been able to take a whole lot of look at, but it's something we can look

into.

COMMISSIONER MCALLISTER: It seems like -- you know, I know there's a robust market for used LEAFs, right, any car that comes off of --

MR. GAGE: With LEAFs, right.

COMMISSIONER MCALLISTER: -- comes off of a LEAF and then goes into the purchase market, and if we do have the locational data around that car, and the VIN number, it seems like we could possibly see what's happening with those vehicles and where it's going.

MR. GAGE: Yeah, the used LEAFs is actually something I've taken a look at. I'm not going to try to recall what I wrote because it was about a year ago, so I'm not going to try to recall it off of memory.

COMMISSIONER MCALLISTER: Yeah.

MR. GAGE: But, you know, they are often sold in the secondary market. But they're also sold out of state or even internationally sometimes, as well.

COMMISSIONER MCALLISTER: Understood.

MR. GAGE: And then you've got some, like I think the -- I think one of the off-lease Tesla's, for example, they just take them back and we don't know what happens to them. Apparently, they're using them for like leased, X-leased models or whatever. They're using it for some project that they're not telling us about.

COMMISSIONER MCALLISTER: In terms of locational data have you done any like disadvantaged community, or overlays, or you know, the EnviroScreen or something like that?

MR. GAGE: I have not done that at this time, sorry.

COMMISSIONER MCALLISTER: Okay. Okay, great. Thanks.

Anybody else have any questions? I really enjoyed this presentation, really terrific stuff. It's amazing how much information we have and the integration of the information is just so enlightening, you know, it really helps us chart a good policy direction.

And Commissioner Monahan, thank you for your leadership on this, it's really tremendous.

So, with that I think do we want to -- let's see, we just had dais discussion. Are we going to wait to public comment to the end?

MS. RAITT: Yeah.

COMMISSIONER MCALLISTER: And maybe, Heather, you know, move on to the production cost modeling.

MS. RAITT: Yeah, so we'll go on to the production cost modeling.

COMMISSIONER MCALLISTER: Great. Thank you.

MS. RAITT: So, thank you. Thanks again, Jesse,

Aniss, and Bob that was really awesome.

So, our next presenters are Hazel Aragon and Paul Deaver. And Hazel and Paul are both analysts in the Supply Analysis Office. So, go ahead Hazel.

MS. ARAGON: Good afternoon, I am Hazel Aragon with the Planning and Modeling Unit in the Supply Analysis Office. I will be detailing you today the input and assumption changes that went into our preliminary 2021 IEPR model.

Paul Deaver, also from the Planning and Modeling Unit, will be describing some preliminary modeling results.

So, the next slide, please. So, below are the topics we'll be covering today. I'll start by giving you a brief overview of the common case scenarios.

Next, I'll cover the changes in the inputs and assumptions built on top of the previous IEPR cycle. And this includes the load forecast, our renewable portfolio build, how we model hydro, and thermal fuel and price input updates.

Finally, Paul will cover our modeling results, including the natural gas demand for electric generation, greenhouse gas emission projections, and plant generation in California.

Next slide, please. We run the three IEPR common case scenarios, the high, the mid, and the low. So, this table shows and overview of the assumptions used for each case.

For example, a high energy consumption case will use the California High Demand Energy Forecast. A low natural gas and greenhouse gas price. A low Additional Achievable Energy Efficiency. And a 60 percent 2030 Renewable Portfolio Standard target.

We are calling our model preliminary, but it's worth noting that the demand forecast is still using the 2020 California Energy Demand Update, which was published on the CEC website earlier this year.

The next slide, please. Okay, I will now talk about the preliminary inputs and assumptions.

The next slide, please. As previously mentioned, we are using the 2020 California Energy Demand Update for what we're calling our preliminary models. The California Energy Demand has hourly loads and modifiers for the IOUs, which we only modify by adding lead days. It also has annual load and modifiers for POUs, which we convert to hourly data using load shapes.

So, we developed load shapes using historical five-year data and use the nearest IOU profile to do

this.

The mid case scenario uses the mid demand forecast with the mid AAEE. The high case scenario uses the high demand forecast, with a low AAEE. And vice-versa for the low case scenario. I've included the link to the 2020 California Energy Demand Update below.

So, the next slide. Outside of California we get our mid case load data from various sources. We use the Western Electricity Coordinating Council as the main source, since most balancing authorities already file directly to the WECC. But we also use the Federal Energy Regulatory Commission 714 filings and any available Utility Integrated Resource Plans when developing our load input data, including behind-the-meter PV.

Which data sources were used depended on the balancing authority and our confidence on the data.

The high and low cases were developed using the U.S. Energy Information Administration 861 regional electricity sales forecast data by category. If the data looked a little off, as it so happened for a few regions, we look at different sources and make the necessary adjustments to smooth out the growth.

The next slide, please. I'm going to get a little more detailed on the out-of-state load, so please

bear with me. In putting together the mid case out-of-state loads, we had to develop average monthly load duration curves. This was based on historical data from balancing authority area or state.

We create a 2018 base year load duration curve to first order them monthly and then re-order the average load duration curve on the 2018 chronology.

For the low and high cases we use the 2020 EIA Annual Energy Outlook to calculate the percent difference between the mid and the low case, and the mid and the high case. This gives us the multipliers to develop the low and the high out-of-state loads.

The next slide, please. We updated the retirements and new projects that have come online since the last IEPR cycle, both in California and the rest of the WECC. So, we pull from a variety of sources, including the Hitachi ABB Energy Velocity Suite subscription database, the WECC Anchor Datasets, the Trade Press, and available IRPs.

We include the recent proposed once-through cooling compliance data extensions captured through the end of 2020. The retirements, additions and OTC compliance are identical for all common case scenarios.

We also include generic renewables, which represent how much additional resources are needed to

meet the state's RPS requirements. And this amount varies between the common cases.

So, the retirements and addition data are captured up to January 2021.

The next slide, please. A total of 5,450 megawatts of additional retirements by 2030 were included into our production cost model. These retirements were not previously captured and they're built on top of the last IEPR cycle. These do not include the plants undergoing the coal-to-gas conversions, such as those in Alberta, Canada, since we already have them included into the model.

And some plants have shifted their retirement dates, such as Intermountain, so these plants don't count as part of the additional 5,450 megawatts of retired capacity I'm talking about here.

WECC-wide, of the 5,450 megawatts, 3,360 megawatts are retiring coal plants, 1,740 megawatts are retiring gas plants, and the remaining 340 megawatts are a combination of biomass, landfill gas, and hydro resources.

The next slide, please. A large amount of new projects added near term throughout the WECC were solar PV, wind, and battery resources. These included existing projects, those under construction, and planned

projects that showed potential for completion in the near future.

We did add new biomass that came online or have plans to come online, but this is a very small amount, less than 50 megawatts. So, I did not include this as a chart. No new gas plants were added, since they were already captured in the last IEPR cycle.

The left chart shows new solar PV capacity added to the model and aggregated by major region from 2020 to 2025. As you can see, there is a large amount of solar development in the Southwest and California. The Southwest Region here represents Arizona, New Mexico, and Nevada.

The right chart shows new wind capacity added and aggregated for 2020 and 2021. When we added new wind earlier this year, we only found data for these two years at the time. So, the Mountain Region, which consists of Colorado, Utah and Wyoming show the largest quantity of wind capacity added in 2020, about 1,500 megawatts.

In 2021, this is in the Southwest, which makes up about 1,400 megawatts.

The next slide, please. For battery storage, this table shows new 1, 2, 4, and 5-hour battery storage added from 2020 to 2023. Again, these do not include

most recent additions after 2021, so it's very likely many more projects have come online since then.

The majority of the additions were located in California and the Southwest. So, as you can see in the chart, the yellow bars indicate 1- and 2-hour batteries in California. The orange bars are 4-hour batteries in California. The dark blue bars are 1-hour batteries in the Southwest. And the lighter blue bars are 4-hour batteries in the Southwest.

The next slide, please. I want to include that as part of a preliminary model we modified the existing renewable profiles just slightly to use Pacific Standard Time. And so, this does not adjust for daylight savings. The reason for this that it provides consistent estimates since solar PV generation can change greatly in an hour or two.

We also used these profiles to calculate our renewable portfolio build using a spreadsheet tool.

The next slide, please. This slide shows a table with estimated RPS energy targets in the mid demand case for all the states that have mandatory RPS targets as of January 2021, for the years 2022, 2026, and 2030.

In California, this is based on the California Energy Demand Retail Sales Forecast and Annual RPS

Target. Outside of California, this is calculated based on the develop load forecasts we just discussed. The percent of the balancing authority load for retail sales that qualifies for their state's RPS, which we get from WECC. And, of course, the individual state's annual RPS percent target.

So, we use these energy targets as a tool to figure out the renewable net short, which is then passed to our spreadsheet tool to calculate approximately how much installed capacity by resources we should add in each scenario. We add this generic capacity to meet those RPS targets where needed.

The RPS energy targets differ between the low, mid and high cases, where the high case scenario has a higher energy target to meet due to high energy load. However, I've only included the mid demand table here.

The next slide, please. Additional capacity is added to the model as generic capacity to meet the RPS target. This table shows an estimate of how much more total mixed renewable capacity California may need in the mid demand case, in 2022, 2026, and 2030 on top of the existing and planned resources already in the model.

You can see how much each resources we have for in-state and out-of-state to meet California's RPS. The amount of projected RPS resources for the high and low

case are scaled respectively higher and lower than the amounts shown here in the mid demand case. Again, I've only provided the mid demand table today.

The next slide, please. We also did add some generic 4-hour batteries according to major region, but only in the high case. While not specific to the RPS, generic batteries were added to the high demand to achieve zero unserved energy and to improve line flow congestions to specific locations. In California, these were also added to meet a reasonable reserve margin and to meet peak load hours. So, no additional generic batteries were needed in the mid or low scenarios.

The next slide, please. Okay, moving along, we updated our hydro generation input data for the IEPR common case scenarios. In other words, these are meant for -- these are not meant for drought scenarios, these are meant for just the IEPR common case scenarios.

We developed historical 15-year average monthly data based on QFER data for California and EIA data for the rest of the WECC, for conventional hydro only.

In California this is about 27 terawatt hours of annual hydro generation. In the rest of the WECC, it comes to about 211 terawatt hours of annual hydro generation.

We add constraints to the CAISO and the Pacific

Northwest to ensure that we model a hydro plant's minimum generation close to what it is expected to actually operate.

The next slide. The nuclear refueling schedule for Diablo Canyon, Palo Verde and Columbia Generating Station were updated using historical patterns for fuel outages. The outage durations last about 5 weeks every 18 months and they don't overlap between the nuclear plants. In other words, you can't have two nuclear plants having an outage at the same time.

It's worth noting that the Diablo Canyon units retire in 2024 and 2025.

The next slide, please. We updated the natural gas power plant heat rates in California based on the 2014 to 2018 hourly public data from the Environmental Protection Agency Continuous Emissions Monitoring System.

But for more information on how we updated this model, you can refer to the staff white paper noted at the bottom.

Next slide, please. For the price updates we start by updating the deflator series in the model. We updated the greenhouse gas prices where a low demand uses a high price, and a high demand uses a low price, and the mid demand uses the mid price.

Paul will present the results on GHG emissions shortly.

We made updates to the power plants start costs and variable operations and maintenance costs to our model's thermal units, which I'll get into a little more in detail soon.

Finally, we included the July 2021 natural gas burner tip prices provided by our NAMGas Team, which Paul will be presenting the results of. This slide should say July, not June, since we managed to squeeze in another burner tip update.

We run iterations with the NAMGas Team, where we basically pass our natural gas use outputs to them and they pass us their natural gas burner tip prices to us, and we cycle through this a few times until both our results converge closely, and we get reasonable results.

So, another iteration may be possible soon, but the results shouldn't differ very much with what we'll be showing you today. However, the finalized results for the natural gas use for electric generation will definitely be presented at the NAMGas workshop later this month.

Next slide. The thermal price updates included cold start costs and variable operating and maintenance costs. The upper table here shows the thermal category

types, start costs and VO&M costs which are noted with the green header columns. And the price difference from the last IEPR cycle, which is noted with the blue header columns.

In most cases, this is a small difference and a decrease in either costs. We match our thermal plants to best fit categories according to the WECC Anchor dataset, as well as available Trade Press information, and data on the plant size, heat rate, and age.

For example, if the natural gas unit is a combined cycle type technology, it takes on the median cost associated with the typical combined cycle category.

The lower table here shows the variable operation and maintenance prices used for biomass, landfill gas, and geothermal plants. These plants previously contained a range of different VO&M prices in the model. Their VO&M prices have been standardized this time around so that the respective technologies all use the same VO&M prices.

Next slide. And then, some items we would like to address, permitting the time, finalize any iterations with the NAMGas Team on the burner tip prices, if possible. Update the renewable and battery portfolio to account for the recent CPUC proposal decision, which

adds 11,500 megawatts of net qualifying capacity. And apply more emphasis on system reliability not only in the summer, but also in the winter.

Our main driver for the resource build is the RPS, not modeling towards reliability. And we're looking to improve this, and especially towards a winter build, when there's less solar in the system and other extreme situations.

So, this concludes the portion of the slides relating to the inputs and assumptions. But I just want to say that this was a big team effort in putting together all these updates, and I hope you can appreciate our team's work.

So, without further ado, Paul will now present the results.

MR. DEAVER: Thank you, Hazel. And good afternoon everyone. My name's Paul Deaver, I'm in the Planning and Modeling Unit, and I'm going to be presenting the preliminary results from our model runs.

Before moving on, just a quick note on notation that Hazel had mentioned earlier for some of the charts you will see. The mid case refers to the mid energy demand, mid price. The low case refers to the low energy demand, high price. And, the high case refers to the high energy demand, low price.

The next slide, please. So, I want to start out with the mid case for annual California generation, just for the years 2022, '2026, and '2030. The first thing I want you to notice is that natural gas used for electric generation does decrease over the planning horizon.

We do see a smaller decrease in 2025, 2026, the years just after Diablo Canyon retires. This creates a small short term need for natural gas just after that nuclear plant retires.

We also see a relatively large increase in solar generation over the planning horizon, and a small increase in wind.

Hydroelectric and other renewables tend to remain roughly constant over the planning horizon.

The other thing to note, we do see a small increase over the years of battery generation. And the numbers presented here are gross generation for batteries. We do not account for charging of the batteries.

Next slide, please. So, I also wanted to show monthly generation for California. Both of the charts here are for the mid case. The one on the left is 2022, the one on the right is 2030. I wanted to give you all a sense of the seasonality of what we project for the generation resources.

So, in the near term natural gas provides most of California's generation needs in the summer months, July through September generally. And then by the outer years, by 2030 we see that December is the only month that natural gas generates more than solar and wind. And also by 2030, in the spring months solar and wind can generate up to four times as much as natural gas, so there's much more renewable energy in the outer years.

The next slide, please. I also wanted to show for the mid case, for California, just the annual generation mix and how that changes over our planning horizon. So, in 2022 the big thing to see here is that natural gas makes up almost a third of the annual resource mix, whereas solar only makes up about a fifth.

And over the planning horizon, by 2030, this kind of switches so that gas only makes up about a quarter, whereas solar makes up over a third of the generation mix. And we also see a modest increase in wind generation over the time horizon.

The next slide, please. I wanted to show this slide just to give everyone a sense of the size of California's generation resource mix. This is for the mid case for 2022. These patterns do seem consistent over the different cases and over the planning horizon.

I've listed out here, for the different regions,

Southwest, Northwest, Mountain, Canada, and Baja California North, and what states are in each.

So, to notice here, California generally generates about 20 percent less than Arizona, New Mexico and Nevada combined. And it generates about 15 percent more than Alberta and British Columbia.

I do want to note that these charts do not include imports. If they did, the bar representing California would be quite a bit higher. So, this is just in-state generation.

The next slide, please. So, I wanted to look at natural gas use for electric generation for both California and the rest of the WECC states. So, as I mentioned earlier, the natural gas use for electric generation does decrease over the planning horizon in all three cases.

As I mentioned before, the years around and just after when Diablo Canyon retires, in two of the cases we actually see a small uptake in natural gas use, and in the low case it's down a little bit. But then after that, the decrease continues to go down.

The other thing to notice on this graph on the left, which is for California, the 2019 IEPR mid case, our preliminary results now do show less natural gas use than in 2019. There's a number of reasons for that.

One of the main drivers is the previous California Energy Demand Forecast was higher than what we have now, particularly in the years 2021 to 2024, as we can see.

We also assumed, as Hazel mentioned, more generation and more resources from solar and wind. We also added in some generic renewablest.

And lastly, we did iterate with the Natural Gas Team to update the natural gas prices, so there's a little bit of a change there.

And we expect future iterations with the Gas Team, but we don't expect to see much of an increase or much of a change in natural gas prices for future iterations with them.

Now, looking at the chart on the right, this is natural gas use for the rest of the Western States. The first thing we notice here is that the trend is more constant. We don't see quite the decreases we see in California. We also see that compared to the 2019 results that our results now show that the rest of the Western States are using more gas than previously.

And there's a few drivers for this. One of the first ones is that there are some coal retirements throughout the other Western States. California's using less gas. And related to their coal retirements, there's also the price of natural gas. And in some of

these Western States coal and natural gas can be substitutes for each other for electric generation, depending on their relative prices.

Oh, and one more thing I forgot to mention, the labels mentioned on here, please forget the 2021 burner tip prices. This is just the low, the high, and the mid price cases as I had described earlier, for both charts that is.

The next slide, please. So, I wanted to look at both natural gas and coal use for the whole WECC. So, first on the left we do see a slow decrease in natural gas use. It's not as pronounced as just California, because we are including more Western States. And we do still see the decrease flattened out just a little bit just after Diablo Canyon retires, but then continues on its slow decline.

And then looking at the coal use, the chart on the right, I did lump in fuel oil and distillates with coal. Those fuels tended to fit together and we did not have much oil or distillate use, so I thought that those would fit better together.

So, looking at these we do see the same sort of decrease in generation from these fuels going forward. However, we do see a little bit of an increase between 2027 and 2029. Some of the reasons for this, the coal

retirements do not happen evenly every year, nor are they evenly distributed over all the states. And there are a few states that did show some increase in demand that that could be causing this, and those are Arizona, Montana, and New Mexico. In those years, that's primarily where that increased coal generation is coming from.

One last thing to note on the coal chart on the right. In the low demand, high price case, both natural gas and coal prices are higher. However, for the coal prices, the difference between the low and the high is much less variable than are the natural gas prices. So, even though we have high coal prices, the natural gas prices are relatively higher. So, even in the high price case we are seeing some fuel substitution there. So, we do see more coal generation, even in the high price case, and that just has to do with fuel substitution between the two fuels, natural gas and coal.

The next slide, please. I also wanted to take a look at natural gas and coal use, these are both for the mid case. I wanted to look at this monthly so we can kind of get a seasonal look on what's going on with these two fuels.

So, first on the left, even if we look WECC-

wide, we see natural gas, its generation does peak, its use for electric generation peaks in the summer months. We kind of expect that. And we do see maybe a smaller peak occurring, you know, in December and January, but not nearly as high as the summer months.

We have the same story for coal. Coal is similar to gas in that most of its generation tends to happen in the summer months.

The next slide, please. These charts are repeated from previous slides. I did want to get coal on one slide, once again just to reiterate that it does have similar patterns as natural gas when we look WECC-wide. And most of it is used, or the majority of it is used to generate electricity in the summer months.

But coal in particular, there are some peaks that we see in the winter months as well, although those are not as large as the summer months. So, I just wanted to point that out that the winter months do still have some coal generation.

All right, the next slide, please. So, let's take a look at some of the GHG emissions that we forecast in California. So, for both of these charts, they are going to include in-state generation plus imports.

So, we do see a decrease for total generation,

on the chart on the left. All three common cases do show a decrease in total generation in millions of metric tons CO2.

And once again, the natural gas use, although not quite as pronounced, we do see a slight flattening out of the decrease in the years just after Diablo retires.

We also graphed the 2019 mid case IEPR for the GHG reductions. And in general these are higher than the 2019 total GHG. They're higher than what we are seeing in our preliminary results now.

And there are a few reasons for that, just looking at California. We do have more solar and wind, along with generating capacity. And there are a few natural gas resource retirements, so we are using a little bit less gas.

And also, as I mentioned earlier, the California Demand Forecast was higher than it is now, it was higher in 2019. So, that does account for some of the decreased greenhouse gas emissions, lower California demand.

So, now looking at the chart on the right, if we measure GHG intensity as metric tons per megawatt hour. This tells a similar story as the total GHG emissions, we see a decrease over time and that decrease flattens

out a bit just after Diablo Canyon goes away.

So, a few reasons for this. Over the planning horizon we add more renewables to the system, so we tend to have a cleaner resource mix later in the planning period, with less gas. And we also, as Hazel mentioned, added some battery storage in and that will help reduce emissions.

Then, as you look at this chart, the three common cases do tend to converge around 2030. That is because we have the same RPS percentage target. They will be different energy values, but they are the same percentage target, so that's why they seem to roughly converge around 2030.

One other thing to notice, the kind of brownish-green line, that is the high demand case, we do see the emission intensity in the outer years kind of dip below the mid case. And that is because, as Hazel mentioned, we did add some generic batteries in for the high case in the outer years, and that helps with the overall portfolio GHG intensity. So, that's why that line dips down a little bit there.

All right, the next slide, please. So, on the last slide I showed annual GHG emissions and intensity over the forecast period.

So, now I wanted to look at GHG intensities, and

these graphs are also in metric tons per hour. So, I wanted to look at these by month and by hour so we get a sense of how GHG intensities decrease by month and over time.

So, those tell a similar story as the previous charts. We generally see the GHG intensities decreasing for all months and for all hours. However, we do see the largest decreases in GHG intensity happening more in the middle of the day, as well as generally in the summer and the early fall months. So, that's where it happens the most.

And another thing to note, the highest GHG intensity hours, they go from about .26 metric tons per megawatt hour to 0.24 metric tons per megawatt hour. And the time of this shifts a little bit. In 2022, these GHG-intensive hours tend to occur in the early morning in August. And by 2030, they are occurring in the early mornings in December and August, so there's a little bit of a shift there.

And one last thing to note about this, that 0.24 metric tons per megawatt hour number, that is about half the GHG intensity of a natural gas plant. So, I just wanted to point that out.

The next slide, please. Thank you, that concludes our presentation on the input assumptions and

preliminary results. We're happy to accept questions and comments from the dais, as well as from the public.

COMMISSIONER MCALLISTER: Thank you, Hazel and thank you, Paul. That was fascinating. And I just am really, actually, even though there's red -- you know, a lot of red around the edges here, if you just look at the absolute numbers across the board, you know, if you had said ten years ago we would be down even the worst hours in the .2, you know, kind of kilograms per kilowatt hour kind of realm that I would have been very happy with that. You know, so we've made a lot of progress I guess is the point. Because that's relative to the rest of the country certainly that's a pretty clean system and across the -- you know, in the green only getting greener, that's great, too.

So, we still have some more to do to spread across -- spread that green. You know, use a peanut butter knife and spread it across the other hours, but that's good progress.

So, anyway, I wanted to pass to the Lead Commissioner here, so Commissioner Gunda I imagine you have some observations.

COMMISSIONER GUNDA: Yes, thank you, Commissioner. So, first of all I think I just want to recognize, Hazel, you said, you know, how much work is

going behind the scenes. So, just to you and I know there's a lot of team that is engaged on not just this, but the SB 100 analysis, the reliability analysis, so much of the PLEXOS team is -- all the roles that the PLEXOS team is playing in answering a variety of questions for the State of California.

So, you know, I'll take you as the point person to convey the thanks to every single person and the incredible work everybody's doing.

I just -- you know, there's a lot of questions here but also, you know, in recognition of the time maybe I just want to tee up a couple of comments at a high level, and then maybe we could have follow-up conversations on this. But I think this allows, as a forum, to communicate also with the stakeholders and what we're thinking, and hence the questions or comments. So, just recognize that.

So, it would be really helpful to understand, you know, especially on 32, slide number 32, you know, how much of our kind of dependence on imports during -- you know, so where are these emissions coming from? Is it emissions coming from imports, in-state generation, and such would be really helpful to understand as we march towards the 2030. And so, it kind of sets some policy guidance on, you know, what is our dependence on

imports, what times of the year, and what times of the day would be really helpful for us to think through.

So, anything that the team can shed light on would be really helpful in a future conversation or at the end of kind of my couple of questions if you want to tee up the answers.

The second high level question is, you know, we have a lot of proceedings going on right now in terms of the IRP. You know, we have the 11,500 megawatts that was recently procured. You know, how are all these things aligning together? Right, I mean like so the generic build that you kind of shared, Hazel, in your kind of comments, is that pretty much aligned with the IRP? You know, how does that differ from SB 100?

So, kind of having context on this would really be helpful. Similar to what's happening on the demand side, the uncertainty and how do we think about demand cases versus scenarios. It might be really helpful for us to think about, you know, what are we getting out of demand cases, so applied cases, versus really like, you know, the scenario development of, you know, there's a lot of variables here and how do we think about that would be really helpful. Because that directly gets into the natural gas system.

And also, the final question is what level of granularly do we have in terms of where the system impacts are happening? I mean, is that resolution pretty much at a state level? Does it give us a little bit more understanding at like a local level to understand the interaction between gas and the electric system? Which is these are the questions that are kind of going through my mind.

And so, before I pass it on I just want to say four years ago if I watched the same presentation, I would not understand the kind of how useful of information that you're providing. I'm just grateful for the team to continually educating me on the importance of this, and I'm recognizing the amount of work the team is doing. So, thank you.

And Hazel, if you have high level responses, it's great. If not, we could follow up separately.

MS. ARAGON: Sure. So, in response to your comment about how does the resource build align compared to the SB 100, we're also doing a separate reliability model, and the current IEPR scenarios.

So, all of these are a little different in, I guess in a certain way, and we do eventually want to I guess merge them together so we have one model that can run like a reliability scenario, the IEPR models, all

using the same resource build. So, we would like to eventually get to that point. Right now, these are all separate branches that we work on in PLEXOS.

COMMISSIONER GUNDA: Great, thanks Hazel. Paul, I don't know if you have anything that you want to add. If not, I'll pass it back to Commissioner McAllister.

MR. DEAVER: We do have granularity down to the plant level, although we don't feel 100 percent super confident about going down to that level. We can do something like groups of power plants to see where emissions are coming from, from that way. So, we can do other aggregations that are more than just the state level, but that does take a little bit of work, and we can definitely look into doing that.

COMMISSIONER GUNDA: Great, thank you. And back to you, Commissioner McAllister.

COMMISSIONER MCALLISTER: Great. I don't have any specific questions. I think this is great information. And yeah, just appreciate all your diligence. And please do also convey my thanks to the whole team.

MS. RAITT: Commissioners, this is Heather. I wonder, we do have a couple of questions. We're a little bit ahead of schedule, I wonder if you want to take them from the Zoom Q&A?

COMMISSIONER MCALLISTER: Oh, do you want to do that, Heather, or should -- should we -- let's see. Who would be moderating that? I can do it if --

MS. RAITT: Matt. Matt Coldwell.

COMMISSIONER MCALLISTER: Oh, Matt. Okay, great. Go ahead, Matt.

MR. COLDWELL: Sorry, I had to get my video back on. So, thanks Heather.

So, the first question is from John Bradshaw and I think this one's for Paul: On slide 23, Paul, he's asking what does battery generation mean?

I think it was a chart that had batteries on the same bar chart with generation resources, so I think he's just looking for some clarification.

MR. DEAVER: Yeah, so those numbers represent gross generation. It's not net. It's not going to depend on or include what charged the battery, or where it was discharging, that's just straight gross generation that we're seeing. It's just kind of an overall level of how batteries are acting on the system.

MR. COLDWELL: Great. Thanks Paul.

And then, the next question is from Luis Martinez: Are there any updates on curtailment estimates as a result of increased renewable penetration?

MS. ARAGON: So, this time around we did not run an analysis on curtailment. But it is something that we can do and we can follow up on.

MR. COLDWELL: Okay, great, those are the only two that we had in chat. So, take it away, Heather.

MS. RAITT: All right.

COMMISSIONER MCALLISTER: Great. So, we are ten minutes ahead of schedule, so that's a good thing. I guess we'll just go ahead then, Heather?

MS. RAITT: Sounds good. Thank you, Paul. Thank you, Hazel.

So, we'll just move on to the presentation on retail electricity assumptions. And so, Lynn Marshall is going to present on that. And she develops the electricity rate forecast for the Energy Commission's Energy Assessments Division. So, go ahead Lynn.

MS. MARSHALL: Okay, thank you. And we have slides up. You can go to the second slide, the flow chart.

So, I'm discussing those forecasted retail electricity rates and that starts with forecasting revenue requirements. And you can think of those broadly in two categories.

First are the costs of power procurement. That's about 50 percent of rates in general. And we're

starting with data reported by LSEs on, you know, their contracted resources, and their costs. And this cycle we're getting data not from IOUs and the large public utilities, but also from a number of CCAs. So, we start with that to account for what's already procured. And then, we use information from the Projection and Cost Modeling Team on prices and resource mix to estimate the incremental cost of meeting our demand forecast.

So, the other half of revenue requirements, roughly, is transmission, distribution, other general, other types of wires cost. And what's notable about that as you think about we aggregate all these revenue requirements and then to get the rates, you simply divide by our sales forecast or demand forecast.

So, this transmission and distribution cost, the majority of them are not sensitive to growth and demand. They're mostly fixed things like maintenance, wildfire management now, customer costs. So, that means that as we're adding building load through fuel switching, or transportation electrification, that load growth actually helps mute the rate impacts from the wires charges that we might otherwise experience.

So then, I'm showing here all of the various CEC models that use the rate forecast. These are at our planning areas levels.

I also want to highlight one new external use of the rate forecast. During the 2020 IEPR, CPUC Energy Division requested that we provide an IOU bundled rate forecast for use in their affordability OIR. And so, we did that last year and they've requested that we do that again. So, I'll come back and talk a little more about that later because there's some important things on differences between what they're doing and what we're doing.

So, next slide. Okay, so going back to the procurement side of things, a major driver of cost is obviously the energy price. Okay, so that we're getting that from the PLEXOS model. But first I wanted to highlight a couple of the key inputs into the production cost model price formation that Hazel mentioned.

And this is the natural gas HUB price comparing the 2019 IEPR with the new burner charge cases that Production Cost Modeling Team is now using. And the key takeaway here is, you know, yes the starting point's a lot lower. But the changes that they have made, our DAP team has made is to account for the impact of maintenance of aging natural gas pipelines that's going to get passed through to the transportation rates. So, we do have a higher rate of growth on those, the citygate prices. And this is SoCalGas, but there's a

similar effect analyzed at PG&E's citygate, and there will be more information on that on the natural gas IEPR workshop on August 30th.

The next slide. Okay, so as Hazel mentioned, another price variable that they update is the GHG allowance price. So, quick recap of how that's structured. We have a reserve price and price floor. We have a soft price cap, and then we have a couple of intermediate price containment points. And if prices hit those tiers, then allowances are reserved, so it's kind of a natural buffer to keep prices from increasing too rapidly.

So, this was -- we're actually now in the first year of this regime. The regulations were adopted a couple of years ago. And at that time some of the economists who were actually involved in the Market Advisory Committee did some modeling of the expected price distribution. So, what they found is there's a lot of uncertainty around the price because it's highly sensitive to small changes in demand. The population of covered entities has a very steep supply curve, abatement cost curve, so there's a very high probability of either being at the floor or at, or approaching the upper tier prices. But there's an expected value somewhere in the $40 to $60 range.

So, why don't you go to the next slide. So, for the last several forecasts we've been using that $60 Tier 1 price as the 2030 price target. And since allowances are tradable over time, you'd expect prices to rise by a non-smooth price path.

But meanwhile, we continue to see the clearing prices at the auction stay relatively close to the floor. We had two auctions in 2020 so far, I think the last one was a dollar and change over the floor.

And one of the factors driving that is the more we pursue complementary policies, in particular on transportation fuels, that lessons the demand for allowances because those entities are also the -- those are the same entities that are affected by those, you know, transportation demand policies.

In particular, the Low Carbon Fuel Standard price is at $180 or $190 dollars a ton. They can also get tax credit for the 45Q tax credit for carbon sequestration. So, that really is great for motivating emissions reductions from transportation fuels, but it has the effect of reducing demand for allowance prices, and it leaves the rest of the industrial sector covered by this program facing a very low price. So, that's one of the -- I think one of the contributing factors here.

And if nothing changed, we'd probably think we

may be staying on a relatively low price path. But things will change. Air Resources Board is planning to take up possible changes to the Cap and Trade Program some time as part of this next Scoping Plan cycle. And can't say what that will look like, there's a variety of changes that they could make. But it seems reasonable to assume that ultimately we'll have changes to the regulatory structure that would drive a higher price. ARB has committed to asking Cap and Trade to do more, so that would imply a higher price.

So, for this forecast I've moved the target to 2030 reaching a Tier 1 price of $83 in 2035. Which means in the near term we have lower prices but, ultimately we do get back on that higher price path.

So, what I'm showing here is the version that was provided to the Production Cost Modeling Team back in the spring. But meanwhile, I'll continue to monitor developments in the Scoping Plan and incorporate any new insights or analysis that come out of that.

Okay, so next slide. So, those inputs go into the production cost model and they provide me with their hourly energy costs. So, I'm showing here their high, mid and low cases. And because of both the lower price inputs and as Hazel and Paul described, with more additions of wind and solar we do have overall lower

energy prices.

And then comparing those, you can see recent CAISO costs of energy served moving to a lower level, with more renewable resources added to the portfolio.

And additional question is do we also need to account for some incremental kind of a green premium to meet RPS goals. And so, I'll assess, I'm going to use the most recent NREL ATB baseline compared to this price, given the renewable additions in the PLEXOS build to assess how much that ought to be, probably declining over time from what I can see.

Okay. And so next slide. So, I have one more input on the procurement side and that is how to value the capacity cost needed to meet any incremental capacity additions. So, they're adding kind of generic additions and I use that capacity price to value that cost.

So, I'm showing here CPUC recently adopted new avoided cost of generation estimates based on four-hour battery storage. So, that's the rapidly declining curve on the right as the installed cost of batteries decline, and they get additional energy revenues increasing, so that decreases the amount of money needed in the capacity payment.

And then on the left side is what people are

currently actually paying for resource adequacy capacity, as reported by the PUC. They collect data from LSEs on their actual RA contracts.

So, there's a big of a gap there in the interim. So, what I'm proposing to do is start from the most recent RA price benchmark, which is something like $73, and escalate that to 2025 where it reaches the avoided cost curve, and assume that at that point hopefully we have less tight supply conditions, and we'll return to market fundamentals and go back to that declining cost curve.

So, those are all the procurement side assumptions. If people have thoughts for me, I'd just love to hear them.

And then, I'll move on to the next slide on the distribution on the procurement cost side.

Okay, this work is just starting because we're using a lot of data that was just recently filed and some of it's still coming in, that's information filed by utilities on their projected revenue requirements, and also reviewing rate actions by public utilities.

And then, an important resource is the PUC's compilation of pending and approved revenue requirements in their Utility Costs and Rate Tracking Tool. They used this starting last year, and actually earlier this

year, to develop some analyses. And that was highlighted in the Affordability Report, a lot of people may have seen. And in that they used -- they started with these pending revenue requirements and then developed their own rate projections to do some scenarios to highlight the potential impacts of the recent rate and possible future rate increases on customer rates and bills. And that effort is really a call to action to highlight the need to find ways to mitigate rate increases.

So, in developing those projections, what they did was assume all of the pending applications before the Commission are approved in full, and then they escalated after those first few years using the CEC's bundled rate forecast, so it's a bit of a blend.

But that study really has a different purpose. Now, in the CEC forecast what we want to include, say in our mid case, is what is the expected outcome of those proceedings. And we know from historically you're not going to get the full request.

And then, yes, the next slide is perfect because this illustrates the difference between those two assumptions. And this table here shows some recent activity for PG&E's general -- general rate case. This specifically is a distribution revenue requirement.

So, you can see in last cycle PG&E had a tester, or revenue requirement request increase of 16 percent. The settlement was 10 percent, right. There's a recent proposed decision on SCE's general rate case that reduces the requested amount significantly.

And both of these, the big driver of the increase is wildfire mitigation and cost recovery. The reduction in the SCE case, for example, was reducing the amount of miles of covered conductors that would be allowed.

So, for the scenarios for this cycle, I'm going to focus on distribution revenue rate scenarios that varied the amount of wildfire mitigation costs that are expended. And that will be presented at our DAWG workshop in September.

And so, that is all I have for today, so happy to take your questions.

COMMISSIONER MCALLISTER: Well, thank you very much, Lynn. So, could we look at that last table? I guess I was curious about kind of beyond the couple of cases -- beyond the three cases that you sort of had data on in terms of where the Commission came down. But that 45 percent ask in 2023 sort of jumps out and I'm wondering what the deal is with that?

MS. MARSHALL: There's a lot. This is really

the first -- you know, they've been doing -- they have wildfire mitigation plans, risk analyses, et cetera.

COMMISSIONER MCALLISTER: Yeah.

MS. MARSHALL: And so what we're really seeing is, okay, we did our wildfire management plan and here are all of the activities we think are appropriate to do.

COMMISSIONER MCALLISTER: Is that the undergrounding cost in there?

MS. MARSHALL: There's some, but not a lot, but not all of it. And they recently announced, you know, another 10,000 miles. That is not in there. So, there's not an application filed for that. But it really is driven by the wildfire mitigation costs.

And one of the things that I've seen happen though with these rate cases, they file the initial one and then they say, oh we have -- based on, say, estimated costs for the current year, and then they say, oh, wait, we have more actual data for this year so they recalculate it. And sometimes the revised requests will come in lower.

So, things can change a lot. But yeah, it's wildfire mitigation that's really the big driver here.

COMMISSIONER MCALLISTER: Yeah. I guess one, just maybe it's really a qualitative question and I

don't think we have numbers on it. But I guess in terms of just all the different elements of rate making, you know, we're talking -- we're developing load management standards, and we're sort of, you know, I think pushing harder on the idea that load flexibility will be an increasing part of the solution, and that a lot of that will be, or should be possibly driven by rates, time differentiated rates.

How does that -- how would a sort of, you know, that aspect, you know, of sort of you're talking really more about the phase one of a rate making rate case, you know, how big the pie is.

MS. MARSHALL: Right.

COMMISSIONER MCALLISTER: How big an impact on what we're doing could sort of an earnest shift towards more, you know, more highly I guess defined time-based pricing be?

MS. MARSHALL: Well --

COMMISSIONER MCALLISTER: I mean in terms of mitigating some of these rate increases, perhaps.

MS. MARSHALL: Oh, in terms of -- well, you can reduce the -- you know, can reduce the additional capacity and that doesn't mean just generation, but distribution. But that's not a big driver of revenue requirement increases. Actually, I think a big issue,

though, for promoting the load flexibility in the context of fuel switching is rate design that allocates cost fairly --

COMMISSIONER MCALLISTER: Yeah.

MS. MARSHALL: -- and not collecting fixed cost as a volumetric rate.

COMMISSIONER MCALLISTER: Yeah. Makes sense, okay. I mean I think there's a little feedback loop there that hopefully can be virtuous in terms of optimal -- you know, utilizing our fixed assets optimally so that we can avoid some of these investments going forward, but it's going to take a while I guess to have that play out, right.

Let's see, I guess on slide 7, you know, you can back up a couple. I really always enjoy your presentations, Lynn, because, you know, you have such an intuitive feel for all the different elements that come together in this world here. And it's really great to see and kind of fun to listen to that.

And I guess on this one I'm wondering, so your proposal seems reasonable, I guess what input have you gotten from -- or, what sort of stakeholder kind of feedback have you gotten on this approach, if any. I guess I'm particularly taking about --

MS. MARSHALL: I haven't.

COMMISSIONER MCALLISTER: Okay.

MS. MARSHALL: I haven't, which is why I put this slide in here.

COMMISSIONER MCALLISTER: Okay, great.

MS. MARSHALL: Because usually, often I've had a capacity price assumptions and it's been something pretty straight forward. But this was a little bit of a head scratcher, so I did want to put this out there. And we will have a DAWG in September. Because of the delays in receiving data, I'm going to be doing a couple of different runs of the rate forecast. So, we will give parties an opportunity to comment on that.

COMMISSIONER MCALLISTER: Okay, that sounds great. And that gap is very notable, obviously.

MS. MARSHALL: Yeah.

COMMISSIONER MCALLISTER: And I guess, you know, it seems like a little bit crystal bally in terms of what those extrapolated years like and where they intersect, or how they meet up -- and how they meet up.

MS. MARSHALL: Yeah. Well, you know, we don't have RA prices for this year or next, but I'm pretty sure that they're not going down.

COMMISSIONER MCALLISTER: You think?

MS. MARSHALL: I have good anecdotal information on that. So, this was kind of my best estimate of how

to merge these two, but I'm certainly open to suggestions from anybody.

COMMISSIONER MCALLISTER: Okay, great. Well, great that was terrific. And I don't have any other specific questions.

And Commissioner Gunda had to drop and Commissioner Monahan dropped a while back.

MS. MARSHALL: Okay.

COMMISSIONER MCALLISTER: So, I think that is it for -- yeah, so Commissioner Gunda had to drop and sends his regrets, because I'm sure I would have enjoyed hearing the rest of your presentation.

MS. MARSHALL: Okay.

COMMISSIONER MCALLISTER: But yeah, great, so good stuff.

Do we have any -- it looks like we don't have any Q&A right now?

MS. RAITT: Yeah. No, we don't have any Q&A. So, if we're done, thank you, Lynn, and we can move on to public comment if you like, Commissioner.

COMMISSIONER MCALLISTER: All right, why don't we do that.

MS. RAITT: Thank you, Lynn.

MS. MARSHALL: Thank you.

MS. RAITT: So, Dorothy, could you moderate the

public comment?

MS. MURIMI: Thanks.

MS. RAITT: Thanks.

MS. MURIMI: Thanks Heather and thanks Commissioner McAllister.

So, moving on to public comment, a few instructions for everybody. If you are on Zoom, please use the raise hand feature. And if you're on the phone, please dial *9. For all commenters, one person per organization may comment and we'll have one speaker per -- oh, we'll have them speaking for three minutes per speaker. Sorry.

So, looking for hands. Again, that's the raise hand feature if you're on Zoom. It looks like a high five, it's at the bottom of your screen. We'll give that one moment.

Seeing no commenters, Commissioner McAllister I'll hand the virtual mic back to you.

COMMISSIONER MCALLISTER: Okay. Well, thanks very much, Dorothy.

Well, let's see, I think we're wrapping up for the day. I want to thank everyone who's still on the call with us and who's been with us most of the day. It looks like there's quite a few folks who stuck it out, so I also thank you for that.

We do really look forward to your written comments, due by August 19th, shown here there's the docket number.

And I think it's been a really great day in terms of presenting sort of preliminary thinking about the analysis and sort of the planning going forward, some of the inputs and assumptions there evolving in earnest in this particular moment, which is a little bit fraught. You know, we are facing some big challenges for the rest of this summer, next summer, and summers after that. And I think that's driving a lot of good thinking about how to -- you know, what additional information we could be using and how we could be collaborating in more and different ways.

And I think we've all heard that staff is headed in a good direction here. And that, you know, on all these different fronts, on the demand assessment itself, and the forecast, and then the various pieces of parts, and on the rates and the rates side, you know, there's just a lot to think about. So, looking forward to keeping tabs on this.

I know Commissioner Gunda is leading the charge here with the Assessments Division Team, with Aleecia and all of our presenters today. So, I want to just thank everybody again. And look forward to the

iterations and all the results as they start coming in and we have a chance to reflect on those.

And with that, I think I will pass it back to Heather to fill this out.

MS. RAITT: I think you've covered.

COMMISSIONER MCALLISTER: Okay. Well, great.

MS. RAITT: Yeah, thank you for your leadership, Commissioner.

COMMISSIONER MCALLISTER: Oh, you bet. You bet. That's what leading the IEPR is all about. And I actually love it because I get to dip into all the different themes along the way and it helps guide the overall kind of conversation, you know, integrating all the different areas. We have a number of -- everything's increasingly interrelated, right. So, our various themes this year, reliability, the forecast itself which we've heard about today, and building decarbonization, and the gas system, all four of those key topics are increasingly interrelated. So, it's an interesting time to be focusing on these issues together in the IEPR.

So, let's see, I think that will do us. Again, really appreciate everybody being with us. And let's see, do you need to say anything about upcoming workshops or anything like along those lines, Heather?

MS. RAITT: Well, we do have upcoming workshops on August 24th and 26th. And so, you can be looking for information about those.

COMMISSIONER MCALLISTER: Okay, great. Okay. All right, well thanks a lot everyone.

MS. RAITT: Thank you.

COMMISSIONER MCALLISTER: We are adjourned for the day. Take care.

(Thereupon, the Workshop was adjourned at 4:07 p.m.)

CERTIFICATE OF REPORTER

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 7th day of October, 2021.

MARTHA L. NELSON,

CERT**367

TRANSCRIBER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were transcribed by me, a certified transcriber.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 7th day of October, 2021.

Barbara Little
Certified Transcriber
AAERT No. CET**D-520