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CALIFORNIA ENERGY COMMISSION

COMMISSIONER WORKSHOP

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Report (2019 IEPR)	)	California Energy Demand
	)	Forecast
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CALIFORNA ENERGY COMMISSION (CEC)

WARREN-ALQUIST STATE ENERGY BUILDING

ART ROSENFELD HEARING ROOM, FIRST FLOOR

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, SEPTEMBER 26, 2019

10:00 A.M.

Reported by:

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P R O C E E D I N G S

10:03 A.M.

SACRMENTO, CALIFORNIA

THURSDAY, SEPTEMBER 26, 2019

VICE CHAIR SCOTT: Good morning everybody. And thank you so much for joining us today. This is our Thursday, September 26th Commissioner Workshop on Emerging Trends for California Energy Demand Forecast. I've been looking very much forward to this workshop and to hearing from our team about some of the emerging trends. One of the things we're thinking about very much, of course, here is how we get to our 100 percent clean energy standards and the types of things that we need to think about in demand forecast as we're modeling towards the future.

An example from the transportation sector is previously, when we were looking at gasoline-powered cars, we look at the time that it takes for a person to get from their home to a gasoline station as one of the factors that we're looking at. However, if you're using an electric car and you charge up at home or you charge up at a fast charger while you're on an errand or something like that, the time to fueling is not quite the right metric or quite the right measure.

So this is an example of some of the things that we're looking at as we look at these emerging trends in California and the types of technologies and other things that we will be using as we head to the 100 percent clean energy standard. So I'm very much looking forward to hearing what some of these.

And let me turn to Commissioner McAllister.

COMMISSIONER MCALLISTER: Yeah. Thank you, Vice Chair Scott. Also really looking forward to this.

I want to just go ahead and thank the Forecasting Team, Siva and Matt and everybody who's going to present and who's behind the scenes here, as well as the IEPR Team, Heather and her team.

So I'm the Lead Commissioner on forecasting issues, on the forecast here at the Commission. And this is, you know, just bread and butter stuff for the Commission. And in a way it's, you know, got great continuity because we've been doing it for 40 years and, you know, increasing, really evolving our tools, definitely in an incremental way, over that time. And it's sort of evolved in perspective and expanded in its sort of breadth, certainly over the last decade.

But I think, really, we're in a moment where the forecast is having to grapple with a whole bunch of issues all at once that really haven't been with us for all that long, and certainly evolving how we approach -- well, Commissioner Scott, you know, mentioned how things are -- how all these questions now intersect and overlap in ways that they haven't. Certainly in the electric and gas sectors, you know, we're seeing all sort of overlap and trends that are going to -- that we need to understand.

So in the electric sector, you know, distribution planning, demand and supply and their interaction, you know, trying to gage what the long-term investments and the distribution grid are going to have to be to deal with our high electrification scenarios and the policies that are pushing us in that direction. You know, all these things are relatively new questions that we're developing the tools to address. And stakeholder engagement in a detailed way is going to be really key to helping us get those tools right and evolving them intentionally over year two-year IEPR forecast cycle.

So anyway, with that, I will pass back to Heather to get us started on the agenda.

So thanks. Thanks, everybody, for being here.

MS. RAITT: I've got a few housekeeping items.

If there is an emergency, please follow Staff out of the building and across the street diagonally to the Roosevelt Park.

And just need to let folks know that we are recording this workshop. And so it's being broadcast, also, through our WebEx conferencing system. And we'll have an audio recording and a written transcript posted on our website in about a month.

And we will have an opportunity for public comment at the end of the day. So if folks in the room want to fill out one of these blue cards, they're at the entrance to the hearing room. And you can give it to me and then we can let the Commissioners know that you want to make comments.

And then for folks on WebEx, you can use the raise-your-hand feature to let us know that you want to make comments. And you can also use that feature if you change your mind and you can let us know that you've changed -- that you don't want to make comments.

Written comments are due October 10th and always welcome. And the notice gives you the information for how to do that. And the notice and all the presentations are posted on our website.

And so with that, we can get started. And Matt Coldwell will give an introduction for the workshop today.

Thanks.

MR. COLDWELL: All right. Thank you, Heather.

So good morning, Vice Chair Scott and Commissioner McAllister. So we really appreciate you being here with us today, as well as everybody in the room and on the phone this morning. So my name is Matt Coldwell and I'm the manager of the Demand Analysis Office here at the Energy Commission.

So let me start by saying that the Demand

Forecasting staff is incredibly excited about today's workshop topics and discussions, so -- because everybody knows, in the room this morning, the energy sector really continues to evolve based on policies, on policies, market trends and customer choices. So some of this evolution is happening fairly rapidly in the near term, while other changes will occur more slowly and play out over the course of the next several years.

So really, either way, for energy demand forecasting purposes it's critical that we maintain situational awareness of these changes and begin to reflect them in our forecasts.

So that's the primary goal of today's workshop. You know, we're really delighted to have a broad range of presentations and discussions on some of the key emerging forecasting trends that have been identified, both by CEC staff, but also by our stakeholders that have been participating in our stakeholder processes.

Today's discussion, of course, is only step one. So step two is going -- you know, is for CEC staff to be able to take the information that we're gathering today and from there -- and from subsequent discussions and from there, really start to develop methods to incorporate those trends into our forecasts.

So let me just spend a couple minutes on the topics that we'll be covering today.

So solar plus storage. So customer-site solar has been, you know, has been and continues to be very successful in California. In fact, you know, earlier this year, California passed the 1 million solar roof goal, so we've had quite a few installations of solar on rooftops in this state. However, we are beginning to see the market sort of move past solar-only resources serving individual customers to solar plus storage, and potentially even plus other types of resources that are aggregated with other customers that are capable of providing grid services.

And so while exciting, forecasting changing load profiles of these customers presents a challenge. And so we are really fortunate to have Sunrun here today to provide their perspective on customer-sited resources.

Building electrification. So

decarbonizing the state's building stock has been solidified in legislature in regulatory decisions in California. Additionally, a number of California cities recently have passed full or partial bans on natural gas in new buildings, really paving the way for all-electric buildings. This really introduces a new variant into energy demand forecasting and system planning as end-use energy consumption switches from natural gas to electricity.

So today we have a presentation from CEC staff on an exploratory study on the impacts of fuel substitution which is being done in parallel this year to the forecast.

So the future of mobility. So, like buildings, decarbonizing the transportation sector is really essential to achieving California's near- and long-term GHG emission reductions goals. So while electrification, obviously, is a big part of that, so are changing mobility options and smarter community design approaches that really have the potential to impact driving patterns and transportation fuel use.

And so really, to be honest, I'm very

excited about the two presentations we have on forecasting the future of mobility today, one from UC Berkeley on new mobility systems and technology, and then one from our sister agency, the California Air Resources Board, on sustainable transportation and communities.

Community choice aggregation. So our last discussion of the day is a panel on community choice aggregation. So according to the California Community Choice Association there are currently 19 CCAs serving more than 10 million customers in California.

So today's discussion on the CCA panel will touch on a variety of topics, including decarbonization programs, demand-side technologies as grid resources, load modifiers, and forecasting methods. So we're really pleased to have Sonoma Clean Power, Valley Clean Energy Alliance, and East Bay Clean Energy here to provide their perspective.

And so finally, system planning. So, of course, while all of today's emerging forecasting trend topics add layers of complexity to energy demand forecasting, equally important is the complexity they add to electric system planning, you know, where infrastructure investment decisions must be made to accommodate these new electricity loads. So we're really excited about our first presentation this morning.

And so unless there's any questions at this point from the dais, so I'd like to introduce Hongyan Sheng from Southern California Edison. She's here to provide SCE's perspective of distribution planning in a high electrification future. She's all the way from Southern California, so let's give her a round of applause.

(Applause.)

MR. COLDWELL: You can come up here.

MS. SHENG: Thank you, Matt, for the introduction. My name is Hongyan Sheng. I'm from Southern California Edison.

First of all, I'd like to thank Commissioners for providing this opportunity for SCE to share its perspective in terms of how to prepare California for its clean energy future. We really appreciate the opportunity as a stakeholder to share our perspectives.

As we all know, California has set its ambitious goal towards the long-term decarbonization to create the clean energy future for California. As we recognize, you know, this is ambitious goal, really what we see is that it really requires the whole economy to participate in this, you know, journey to help the state to get the long-term goal.

As we are from the electric sector side, we're looking at electric sector is, you know, getting more and more clean, what is the more affordable way for California to reach the 2030 goal, for example, you know, to help us really be successful in the long-term decarbonization goal? We really see that it does require significant electrification from both transportation and building sectors to help reduce the carbon emissions from those two sectors.

So I'd like to start with, you know, how we see what is required to help California to get to its long-term clean energy future. And then share our perspective in terms of how likely we are looking at California getting to that long-term future. And then share some, you know, preliminary evidence or insight we have gained from SCE side in terms of the potential impacts we'll be getting, you know, as we're trying to move toward that long-term future and how we need to be able to react to those transformations and be able to plan for the changes to happen to support a better, you know, California future.

So when we update our long-term view towards what is the feasible cost-effective pathway for the state to reach its long-term GHG goals, we saw that, similar to CEC's previous decarbonization, deep decarbonization study, that a significant high level of transportation electrification is needed. We are looking at more than 7 million light-duty electric vehicles, for example, are necessary for the state to meet the 2030 GHG goal.

And, you know, the graph is not necessarily about the differences we see in terms of the levels we need to reach between the CEC study and SCE study. It really is kind of eye opening for us to think about the level of the future electric vehicle penetration, how different it is to the current world. If you imagine, you know, 1 out of 50 vehicles on the road is from electric vehicle today, that's going to be several ten times more by 2030, which is what we look at what's required to really clean the transportation sector. So that's a tremendous change from the transportation electrification sector.

And similarly, when we look at the building electrification, the building sector, we also found that a significant level of building electrification is required. More than 30 percent penetration from both new home market, as well as retrofit market, would bring us a more cost effective and feasible pathway to reach the state's long-term clean energy goal.

So this, you know, may sound really eye opening, you know, how can we move all the levers to help the state to get there, even though we recognize that the high significant level is required? So I'm really excited to share with you some of the positive experiences SCE has been going through and, you know, to help you, you know, see similar to us that, you know, there's a, you know, likely hood that, you know, we as a state, if we work together, we can get to that high electrification future.

From SCE's transportation and electrification program side, our program folks have been working on programs designs to really help our market customers to overcome barriers in terms of availability, affordability and awareness to help move the levers for California to build that high transportation electrification future. We have the Charge Ready Pilot Bridge Program. And, you know, depending Charge Ready 2 Program with significant investment to target for a significant number of charging port deployment across Southern California. Today, we already installed more than 1,100 charging ports but there's a lot more to come.

And one exciting recent movement is that our program folks worked really creatively to be able to tap into the multi-unit dwelling sector, which we know is a very challenging sector for, you know, the adoption of electric vehicles due to the convenience of charging. So we're really excited to see that, you know, sectors, you know, going through the transformative changes through our program. And we hope there's more we can bring out to overcome those barriers.

Similarly, from the medium- and heavy-duty transit bus, you know, area, our -- SCE's Charge Transport and Transit Bus Programs also broke ground with the investment and really targeting for more infrastructure to help enable the fleet to convert their vehicles into, you know, zero-emission vehicles.

So from our program side, we already started seeing that there is more application, more activities going on. And we are really excited about, you know, serving as the agent to really overcome the barriers.

In addition to this, you know, we also are excited, you know, by working with, you know, CARB, for example. We are looking at -- you know, there's more policies. You know, some of them already came, you know, to support the medium- and heavy-duty electrification. And we anticipate, working with CARB, that there is going to be more regulations that's upcoming that will help further facilitate the, you know, electrification of the medium- and heavy-duty bus sector, which will greatly help with the, you know, reduction of emissions, carbon emissions.

So some of the policies, as you are aware, that we have the SB 350, Utility Infrastructure Program, and something that's forthcoming, for example, the Advanced Clean Truck Program, all these, you know, policies and regulations is really going to bring significant transformation as we see through specific sectors. And you know, to lay it all out, we'd like to really help you understand that this really means a lot of things that we have to think thoroughly through as utility planners how to better prepare for that transformative changes from a great operation side to ensure the reliability.

From the building electrification side, we also see that more programs, policies need to be developed to overcome barriers to enable adoption of building electrification. We're excited that, you know, some of the programs' policy developments are already breaking ground but, you know, we expect more will be, you know, upcoming.

The good thing, the positive thing is that -- most encouraging thing is that, based on recent studies, there is already indication of the economics, you know, from a cost effectiveness perspective that, you know, many of the residential, single-family home, for example, already would be seeing the economics for electrified homes with, you know, space heating, water heating. So, you know, the economics there, and how do we help overcome the barriers for more electrification choices to happen?

So I hope that's, you know, giving us a really positive feeling about how likely California will get to that ambitious clean energy future.

So when we look at what does this mean for our grid, you know, specific areas that we recently have looked into is the medium- and heavy-duty electric vehicle, you know, through the SCE Charge Transport Program applications, we were excited to get, actually, many applications in a very short time, you know, a few dozen applications that, you know, really kind of overwhelm us as utility planners, you know, how to accommodate all those customer requests to, you know, help them enable them to electrify their fleet.

So when we looked further into the nature of those applications, we saw that, you know, these projects potentially could create significant impact on distribution and sub transmission systems because the sizes of those projects could range, you know, from less than a megawatt to, actually, a couple megawatts. And that, depending on, you know, where those projects are located, it really could create significant constraints on our distribution system.

The preliminary data shows on the map here just service indication, as you can see the clusters of those projects, you know, they can really be concentrated in the local areas which, you know, will bring different impacts on our distribution grid.

So, you know, how do we prepare ourselves, you know, for this upcoming -- these upcoming activities which, you know, are exciting things that we see is necessary to help us get to the clean energy future?

First thing we reacted to is, you know, how much time do we have to be able to reflect these things into our planning that is, you know, necessary for us to be able to help customers to go through their transformation? Typically, when we look at any project that would trigger, you know, any kind of, you know, upgrade for our distribution system, depending on what kind of, you know, upgrade need it is, it ranges from, you know, 1.5 years, for example, for a simple distribution line extension to 7 to 10 years, approximately, for building a new substation or, you know, creating a new sub transmission line.

So we recognize this is really challenging for us in terms of preparing our distribution grid for the future transformative changes because we have a lot of work to go through to support our customers.

Even when we look at, you know, in addition to the traditional ways of bringing those additional upgrades of infrastructure investments to support the growing need, if we were to consider the alternative mitigation, you know, method which is looking at, you know, deferring our transmission needs through distributed generations, it typically requires us to build our planning view for those upcoming needs three to five years ahead of time because of the, you know, long-term planning need. So this definitely gives us, really, a forewarning sign that we need to be well prepared for all these transformative changes.

So in addition to the long lead time that is necessary for us to prepare our, you know, grid planning, we're also looking at how can we reflect the incremental local load growth into our distribution system planning?

Currently, we are required to apply existing IEPR forecast for the ten-year distribution planning analysis. But with the rapid development from -- as we talk about the program, you know, and code standard development, policymaking and the regulations, through the high -- making, you know, the high electrification future, it really required us to start, you know, reacting to those changes quickly enough to adequately forecast the future incremental demand growth across the planning horizon, you know, in a timely fashion.

So we, you know, really started seeing that, you know, there needs to be a collaborative process for utility planners to work with Energy Commission staff to develop a process through which we can, you know, bring the knowledge together and assess the needs for any incremental local load growths that our utility planners need to reflect in their planning so that we can well prepared ahead of time.

In the long term we already see that, you know, helping, you know, bring out more utility local knowledge to help, you know, align the IEPR view with what, you know, different things that utility planners are seeing in the fields. And be able to also introduce a high electrification policy scenario forecast that's part of the IEPR would be really ideal, or facilitating the longer term planning, including the PUC's Integrated Resource Planning, for example. It would really be great to enable a lot more close examination of the future implications across the planning horizon through that high electrification scenario development.

So that's my presentation. I'd like to open it up for questions.

VICE CHAIR SCOTT: Sure. I had a question for you back on slide nine, the previous slide, you're bullet number three, in terms of developing a new process between CEC and the utilities.

Do you envision something like the Demand Analysis Working Group or a collaboration like that for this, or what are you thinking when you say a new process?

MS. SHENG: Yeah. Previously, SCE

planners had worked with Energy staff -- Energy Commission staff, Nick (phonetic) and Siva's team, to, you know, help bring the knowledge toward -- around the local known load growth that may be outside of IEPR. But that process was not part of a formal process which we now see that it becomes more critical as we start getting more of these newer developments as part of the transformation toward a high electrification future.

We really see the need for us to have more collaborative efforts to inform the Energy Commission, and also build the common understanding towards what's the necessary incremental load growth that we need to put into our planning, we'd like to build a formal process, if possible, so that we can gain a deeper common understanding across the planning assumptions that will be utilized for our distribution planning.

So, you know, utilizing the existing DAWG forum, you know, that could be really helpful.

VICE CHAIR SCOTT: Thanks.

COMMISSIONER MCALLISTER: So, yeah, I want to sort of dig into this a little bit more too. So, you know, formal can mean different things. And so I guess one, you know, one concern that we all have, I think, is how to optimize costs and not -- you know, certainly take care of reliability, that's job one, but also not duplicate investments unnecessarily; right?

So you've talked a lot about the distribution planning effort. And I guess I want to ask if you have any thoughts about how that can dovetail efficiently or optimally with, you know, the sort of transmission level, you know, the more higher voltage distribution, you know, subs transmission investment conversation that, you know, more is sort of tilting over towards the ISO, for example, who does transmission planning.

You know, how we do we have it both ways where we're not overinvesting but we are taking care just at the right level of reliability at the distribution level?

MS. SHENG: Yeah. So that's a really good question.

SCE's transmission distribution system is unique in the sense that the needs we are looking at is pretty much at the local sub transmission, the distribution level. We may not see any need at the bulk system transmission level which, you know, CAISO would be looking at the, you know, transmission-level reliability. But the needs we're looking at is, you know, it's something that the transmission solutions will not be able to solve, and that's really what we'd like to address. We also need to ensure the reliability at our distribution system level.

COMMISSIONER MCALLISTER: So when you say a new process, could you describe what that means, kind of analytically, in terms of how granular we would need to take that discussion? Are you talking at the substation level, sub level? Like what's your kind of -- how rigorous do we need to be at how localized a level?

MS. SHENG: Yeah. For the examples I shared earlier, typically we're looking at the projects that is, you know, at a specific site. And those sites are potentially served by multiple, you know, Edison facilities which could be, you know, simple circuits or relatively larger substations. So, you know, it will involve, you know, we examining, you know, how much impact we will need to examine across those facilities that will pick up the needs from those projects.

COMMISSIONER MCALLISTER: So in terms of tools for forecasting, you would bring that kind of -- that level of information to a forum at the Energy Commission as part of the forecast or, you know, in some complementary form, like the DAWG or --

MS. SHENG: Yeah. Definitely, this will be an exciting opportunity as we look at working with the Energy Commission Demand Division staff, the whole team, in terms of how to establish the key components for us to be able to closely examine the need for incorporating those incremental load growth. I think it’s something that we believe we need to work through with Energy Commission staff to really build an efficient process for us to get the common support.

COMMISSIONER MCALLISTER: How would you envision that process sort of in the forecasting context, coordinating with or informing the Public Utilities Commission in terms of their distribution system planning effort, you know, and cost allowances and things like that, that they would be having, you know, a discussion that they would be having with you about the rate base, et cetera?

MS. SHENG: Yeah. That's exactly where we're coming from because, currently, under the guidance of Public Utilities Commission over our distribution planning effort, the general guideline is for us to apply the existing IEPR forecast. We actually then further disaggregate the IEPR forecast down to our distribution planning level.

COMMISSIONER MCALLISTER: Right.

MS. SHENG: As we look at, you know, those incremental activities that will drive new type of need to help state enable to, you know, a high electrification future, if that's not part of the existing IEPR forecast, how can we, you know, have this process where we would gain Energy Commission staff support for us to incorporate the additional local load growth so that, you know, when the Public Utilities Commission is looking at their decision in terms of approving the prudence of a utility's potential future investment, they would have the strong support from Energy Commission staff's assessment in terms of the reasonableness behind those, you know, reflection of the planning assumption changes.

COMMISSIONER MCALLISTER: Okay. So, yeah, sorry to make you repeat it a little bit there. But, yeah, this seems like a potentially significant new lift within the context of the forecast which, I think is appropriate. But we need to think about sort of how we remain accountable but make it not completely onerous in terms of just the level of effort.

So thanks for that. I don't have any other questions.

VICE CHAIR SCOTT: I had one more question, if you have thoughts on this, and if you don't, that's okay.

I'm thinking about things like cars, electric cars, or battery storage which can be both supply and demand. And do you have thoughts on the best way for us to capture that kind of thing within our forecasting? Right. So I guess what I'm wanting to make --

MS. SHENG: Yeah.

VICE CHAIR SCOTT: -- if we're not

looking it at on the demand side, making sure we capture it on the supply side, but if we're not looking at it on the supply side, making sure we capture on the demand side, except for it crosses both. So how do we -- if you have suggestions for how we best make sure we're capturing those types of technologies as we forecast forward, right, because we'll see a lot more of those, I think, as we get to the 100 percent clean energy standard.

MS. SHENG: Yeah. That's really and interesting development perspective. From my perspective, I think in the longer term future, when we start getting more electric vehicles in the space the batteries become potential resource on the grid that we can potentially draw from to support the optimization of the grid ideally.

But now I think the bigger challenge between now and then is how do we enable the market transformation for us to get there. Only when we get to see so many EVs on the road, we can start meaningfully optimizing those batteries to support the grid operation in a different way, for example, potentially optimize the GHG, you know, emissions at different times, but without the scale. And I think there’s a lot of things that we have to work through from an engineering perspective or from the technology, enabled technology perspective. There’s a lot more, I think, to be worked out for us to be able to leverage that scale once we get there. And hopefully it will bring us more cost effective ways to leverage those as additional generation resources.

COMMISSIONER MCALLISTER: I would just throw out the same thing with respect to buildings, you know? I mean, again, ratepayers have to pay for all this; right? So EVs are a new load that we need to manage and could be a benefit to the grid if we know how to use them properly. And the same things applies to buildings.

So I guess, you know, really, I would ask, as we try to figure out how to make recommendations for investments in the distribution grid, that Edison, you’re particularly well placed, obviously, to inform this discussion as, you know, the electric-only utility here in the state, to help the rest of us understand, you know, what that optimal level is.

You know, we need to invest in our buildings so that they can -- load level, so that they can, you know, use low carbon electricity when it's available and avoid using it when it's not, avoid using electricity when it's high carbon.

So anyway, grid flexibility is going to help us optimize these investments and be the light touch on ratepayers over the long term. So we're going to rely on Edison, really for the data, to help understand how that should happen. So I appreciate your active engagement.

MS. SHENG: Thanks.

VICE CHAIR SCOTT: Great. Thank you for being here. Really appreciate it.

MS. SHENG: Thank you.

VICE CHAIR SCOTT: Our next presentation is going to be customer-sited resources providing grid services.

MS. RAITT: Oh, here. Come on up.

MS. MCMAHON: Good morning. I'm Rachel McMahon with Sunrun, and this is Nathan Wyeth. Thank you for the invitation to present to you today.

What we offer in this presentation is an overview of scenarios in which -- is my microphone on? -- okay, good, scenarios in which Sunrun's residential solar plus storage systems are used for services beyond the host customer. So increasingly, resources located behind the utility meter are providing services to the grid and to the serving entities, the wholesale market, et cetera, beyond the boundaries of the host customer's load. And such an evolution necessitates the way that we plan for those resources and contract for those resources.

And so to that end, our presentation also includes some recommendations as to modifications to the load forecasting process with the aim of ensuring that resource providers, as well as procuring load serving entities, obtain the full value for any distributed energy resources that they procure for additional services.

And with that, I'll turn it over to Nathan.

MR. WYETH: Hi everyone. Glad to be here.

So just briefly on Sunrun, we are the nation's largest residential solar provider. We, over the last 13 years, have brought residential solar to about 255,000 customers, coming up on 2 gigawatts of capacity nationwide, and that's primarily a fleet of solar installations that we actively monitor and manage. In the last three years, we very rapidly made a shift to incorporate battery storage into our new installations, starting in Hawaii, and now California is our largest market for that product.

And with that, as Rachel described, we have begun focusing on how that battery can provide the most financial value to customers in the form of, for example, time-of-use bill management, in addition to emergency backup power. But then we think there's a lot of ways it can go beyond that to provide a range of services to the grid. And we think this raises interesting questions, particularly in relation to how residential load is modeled and expected to occur that are worth considering so that that value can be fully realized.

So just to go one layer deeper into what we mean when we say there's additional value that can be delivered to the grid from a battery that's managing time-of-use rates. The standard way that you might anticipate a PV-paired battery on a residential meter would manage a customer's bill would be to charge from solar during midday periods when the value -- the cost of the retail rate and the value of net-metered exports is now lower and going lower, and to charge the battery and use that to discharge in the peak period to reduce the customer's load or, potentially, export back to the grid. So that basic function is straightforward.

But then there's, obviously, a lot of value in the hour-to-hour or even minute-to-minute pattern that the battery could deliver in terms of charging and discharging, as well as capacity value that can be provided, for example, by a proxy-demand resource or other potential load modifications.

This can be -- you can operate a battery in that way individually or it can be looked at in aggregate. And so these graphs are just pulled from a presentation where we were describing for an LSE how you would take hundreds or even thousands of individual sites and modulate the charging and discharging to produce an aggregate shape that would respond to particular needs, again, whether energy or capacity.

So one of the questions that we have begun to wrestle with as we've tried to advance this approach within market constructs in California comes down to how batteries might be expected to respond to time-of-use rate structure which is the direction that, you know, California has gone in and soon, you know, the default will be time of use for residents, for the vast majority of residential customers across the state.

This graph is -- actually, you don't need to pay too much attention to the lines in trying to decipher what's going on here because our point in showing you different battery discharge profiles during the peak period is to say that any of these discharge profiles have the same economic outcome for a customer because any battery discharge profile during the time-of-use period will result in the same load reduction or exports that accrue to the customer's bill.

So stepping back a little bit, we think this raises an important question about how you can forecast storage and -- sorry, was that a question? -- oh, okay, and in the sense that we believe that battery storage charging and discharging, while it happens behind the meter in the same way, in the same place that load occurs is a bit fundamentally different. And while it may be arbitrary whether one person turns on a light or turns off a light during that peak period, you know, a pattern can be predicted.

And it is much harder to apply that same logic to batteries if they're not informed or integrated with the market, so -- which is to say that absent an active management of the battery for -- in a market-informed or market-integrated basis, you might have battery discharges being set sort of by default by a manufacturer.

We have three or four, you know, residential battery products on the market today for the most part. In the future, you could have dozens from dozens of manufacturers, dozens of software platforms managing them. And all it would take to produce a shift in battery output from one hour to the next across, potentially, hundreds of thousands of batteries would be someone saying, okay, instead of discharging at 5:00 p.m., let's move all the batteries to 6:00 p.m. And that would have no impact on the customer, no impact on the customer bill, but a large impact on the grid.

And so we believe that the active management of batteries in a market-informed or integrated way adds value. And we need to be able to account for that value in relation to forecasts. So I think there's a lot that could be delved into there.

To bring this back to some specific use cases, I'll just go into two examples of how we see this more active management adding value that we believe needs to be able to be recognized in relation to forecasts.

So one, the first one I'll touch on is Sunrun's recent contract we signed with East Bay Community Energy to provide local and system RA from a set of distributed solar and storage installations that we plan to install on multifamily sites in Alameda County with a focus in West Oakland.

So for the customer the battery will manage -- will charge and discharge from behind-the-meter solar. It will manage time-of-use or demand charges based on which tariff, primarily the common load of the sites are on. And then we expect this to then be used as a proxy demand resource to reduce load in the ways that will deliver resource adequacy to EVCE.

The second example I want to touch on comes from outside of California but we think is a construct that has a lot of value. In ISO-New England the forward capacity market has a number of different capacity products but one of them is what's called passive demand response. And this is, essentially, daily load shaping in relation to peak capacity needs in the summer and winter. And it could be -- there are some corollaries to what used to be permanent load shift or, I guess, still is permanent load shift in California but enables a battery to shape load to the needs of the wholesale market on a daily basis, but it's only providing capacity value. It's not active in the market, providing energy value.

And in these places, it's more backup power for the customer. There's not, generally, time-of-use rates. And in addition to the capacity in the wholesale market there is also potential to reduce transmission charges for the utility. So that's another construct that we think is really promising.

I think that's my last slide and I'll turn it back to Rachel.

MS. MCMAHON: So the following three recommendations, as I indicated at the outset, are suggestions that we have for modifications to the CEC's load forecasting process to adequately capture the value of these systems to the benefit of the procuring load serving entity, as well as the resource provider.

And to make a clarification that I didn't say at the beginning, so as Nathan mentioned, one of our projects will be integrated into the market under the proxy demand response product. We would like to be able to offer products to load serving entities that do not require market participation. It's a particularly difficult path for distributed energy resources, and particularly behind-the-meter residential resources, so -- and this presentation doesn't go into that. But in any case, I'm happy to answer any questions about it.

And so for the most part, well, still today, and I imagine into the foreseeable future, the most valuable product that -- to a load serving entity is capacity. And so our first recommendation is aimed at better aligning the load forecasting process, particularly the assumptions for autonomous adoption of behind-the-meter resources, with the local capacity procurement process at the PUC and the local capacity technical study process at the CAISO.

And so this recommendation is to, instead of forecasting assumptions of distributed energy resources by the three transmission access areas in the state, instead, planning -- forecasting them by local capacity area. And the benefit of this is it would be easier for a load serving entity to verify forecasted DER assumptions and procurement.

And I should say, to back up a little bit, as you may or may not have heard, as this has been quite controversial over the last couple of years, is that in some utility solicitations for behind-the-meter resources, we wind up in this somewhat nebulous conversation of whether or not our system is already baked into the load forecast. And there’s no way to verify that and no way to prove it and no way for a load serving entity to look at its load forecast in a particular local area because, of course, these are inherently local resources that are providing local resource -- or local reliability capacity, ultimately, is their true benefit. There's no way to kind of parse that out of what are they buying behind what would already have occurred?

And then another benefit, as I already kind of touched on, is better alignment with the supply-side resource adequacy process in order to get equivalent capacity credit, and also so the CAISO can include -- can more specifically include resources in its local capacity technical study process. So ideally this will wind up overall driving down procurement costs. But in any case, it's the first of our recommendations.

And the next two recommendations somewhat go together. So in our analysis of LSE IEPR supply forms, they include supply-side resources and not behind-the-meter resources. And so our recommendation is to include in the LSE forms an extra sheet for behind-the-meter dispatchable resources and for an hourly forecast, so an 8760 forecast of when they expect these resources to be dispatched.

Let's see here. Now, as Nathan kind of

alluded to, behind-the-meter solar and storage systems are predominantly dispatched according to rates. A multiple use application scenario, this won't always necessarily be true. And, of course, as the -- how do I say? -- as the needs change on the grid, this will continue to not necessarily -- it won't -- let me back up. It will no longer be appropriate to put -- to plan resources just based on peak but rather being able to shift generation to shorter periods, et cetera. So enabling LSEs to put hourly data, particularly for resources that they've procured outside of -- that they've procured and contracted for would enable a far more accurate reflection of what these resources are actually contributing and what other resources are needed.

And then the penultimate bullet, so LSEs should have the ability to submit specific dispatch use cases, so these could be use cases that are set beforehand based on an assumption of -- based on contracted resources or resources that they expect to contract for.

And then our third recommendation ties pretty closely to this one, which instead of a load serving entity developing these scenarios, the Energy Commission, instead, would do so. And so to develop some assumptions for behind-the-meter -- and we're only speaking about solar plus storage here because that's what we do, so it may be appropriate to do this for all behind-the-meter resources. But I just wanted to clarify that our recommendations are focused on solar plus storage.

So at any case, in this recommendation the Energy Commission could project deployment of a certain number of systems and predict how they will be utilized, so it could be a few different use cases. They could use the three TOU rate use cases that Nathan presented. And then load serving entities will verify those assumptions and provide evidence, like ex-post, that assumptions could be adjusted based on contracted behind-the-meter resources providing grid resources.

And those are our recommendations in a nutshell. And, of course, forecasting is not what we do, so we were just looking at it from the perspective of a resource provider and what we want to offer our customers, so thank you.

COMMISSIONER MCALLISTER: Thanks for

that. Really interesting. So I guess I have a couple of questions.

So in the scenario you just described where, you know, there's aggregated behind-the-meter solar plus storage and storage is being sort of actively dispatched, you know, what does that look like in practice in terms of how does the aggregation -- how would you see the aggregation happening? What's the visibility? What's the settlement? What's the accountability? I mean, ex-post kind of scares me a little bit. It seems like, you know, you'd want some, basically, real-time visibility into that, certainly if you're an LSE, but also, you know, we would want that as backup for any forecasting work we would do.

MR. WYETH: So let me try and describe how we would think about operating and tell me if I'm covering what you're getting at.

So the starting point that we would operate from, and we imagine others would but can't speak for every business model or technology, we would incorporate our customers and, theoretically, aggregations could include DERs deployed by multiple developers via -- with a customer agreement that would say, you know, so this DER is providing bill savings to you but we may also utilize it for additional things and we'll settle up on our -- you know, through our power purpose agreement or otherwise if we modify what would have been your bill savings. That enables us to look at the resource in terms of its capability in excess of what is provided to the customer and offer that in the CAISO or via the kind of load modification scheme that we described within LSE.

For our systems and I think the typical, what you typically see, for a battery will be the ability to directly meter the output of the battery at the inverter, so you'd have a revenue-grade meter that, you know, in different jurisdictions are being -- is being accepted as equally valid with the utility meter in terms of verifying data, that data would be aggregated and shared, you know, in a -- if we're working with an LSE to deliver a particular load shape, for example, that would be delivered to them. I think that data can be structured and delivered to the CEC. In the CAISO context, it's also being structured and delivered back in that settlement process.

MS. SIMONSON: And one clarification as to my comments on ex-post, and so these recommendations are specific to a new project. There will be some assumptions going in as to, well, for a new project or for a use case, you would develop some assumptions about how the resource will operate. And then you can verify with ex-post data to then inform the forecasting of that resource going forward.

COMMISSIONER MCALLISTER: Okay. Got you.

So on the technical front are you -- well, if you're going to do this -- so you showed the graphic of the time of use; right? And so within the time of use, you know, peak period, you could dispatch in any number of different ways. You know, there are infinite possibilities. So if you were to do this frequently, you're going to be cycling that battery a lot. And, I guess, have you thought about the -- you know, the lithium ion batteries or whatever you're putting in have a cycle life. So have you sort of thought about the cost of that and the contractual issues there?

MR. WYETH: Yeah. Certainly. And this

is, in our -- in Sunrun's predominant business model we actually are owning -- we own the battery and we are providing the service to the customer in a PPA or a lease, so we do. We think every day about the condition of that battery because we have to replace it if it degrades beyond a certain point.

If you have a time-of-use rate for which the battery is cycling, typically, once a day, maybe its cycling every weekday over the year, maybe not weekends if the rate differential isn't sufficient, you're doing 270 or 365 cycles a year, what you would be doing in a lot of cases would be modulating the pattern that its discharging. And it's possible that could have a very incremental impact on degradation if you're discharging at the maximum or discharging over -- you know, at a lower level over a longer period of time. But we see that within being within the band of degradation that's well worth it in relation to the value that it can deliver.

COMMISSIONER MCALLISTER: What battery life are you sort of anticipating in this scenario?

MR. WYETH: So today, we're operating

with equipment that's warrantied for ten years, typically 3,600 cycles, so effectively, daily cycles for ten years. We're seeing warrantees being offered beyond that period and, sort of from vendors, so out to 15 years. So that's the timeframe that I would tend to expect.

COMMISSIONER MCALLISTER: Okay. I guess that's all I have. Thanks. Okay. Great. Thanks a lot.

VICE CHAIR SCOTT: Thank you. Thank you very much for being here.

MS. SIMONSON: Thank you.

VICE CHAIR SCOTT: We will go on to our next presentation, which is the scenario assessment of building electrification.

MR. JASKE: Good morning. Mike Jaske, Energy Assessments Division staff. And what I'm going to do today is provide an overview of a project that has been designed to try to reveal some broad consequences of different levels of residential and commercial building electrification.

So as these three bullets indicate, really the purpose of this exploratory study was to understand the relative importance of different assumptions that go into making these kind of projections. We wanted to develop a tool that could assess the annual energy implication of substitution of electricity for natural gas.

And then also, in the second stage, to develop hourly load impacts for that incremental electricity energy. And this would provide a starting point for assessments of amount and type of generation resource additions that might be appropriate to this incremental load. And I believe that there is going to be a presentation about the preliminary version of a major electrification scenario at a workshop at the end of October, so sort of splitting the demand side and the supply side into two parts.

And, in fact, even the demand side portion of this effort is being split into two parts. What I'm presenting today is a description of the sort of background of building electrification scenarios that were developed to assess the implications of different progressions of new construction, electrification, retrofit electrification, and different levels of depth of that, develop some understanding of the sensitivity of those results to different hourly load profiles for different end uses and give a preliminary version of these results to our system assessment people so that they can do some electric generation impact assessment.

In the second part I'm going to present the actual detailed results, which is just too much to do all in one sort of half-hour session. So -- and in the meantime, between now and then, I maybe tweaking the scenarios a little bit and perhaps even some of the hourly profiles that I'm using to generate the results.

So the basic approach that we're following in this effort is to start from the staff's 2017 IEPR Natural Gas Demand Forecast. So there we have a ten-year projection of what residential end use load, commercial building end use load. And that can then be the starting point for certain assumptions about how much of that natural gas load is converted to electricity and, in the second step, converting that annual electricity energy into hourly impacts.

So we're going to devise some scenarios that take advantage of this sectoral and end use level starting point data, kind of the baseline forecast, quantify the amount of natural gas displaced, annual energy produced, and then, ultimately, hourly load impacts.

So this is just a simple listing of the various policy initiatives that are encouraging building decarbonization. And many times these are thought of as building electrification efforts. They don't necessarily have to be but certainly that will be the assumption for this particular study.

Many of these provide a direction, like our Title 24 Building Standards have eliminated either a real or a perceived barrier to all-electric residential dwellings. SB 1477 is actually providing some explicit funding for fuel substitution activity but it's quite small in proportion to the hundreds of millions or billions of dollars that might eventually be required.

AB 3232, of course, directs the Energy Commission to conduct a cost effectiveness assessment of a major displacement of natural gas. And other things are going on that are all clearly in the direction of some kind of electrification.

There are a lot of unknowns, just a of

which are listed here at the bottom of this page. Are we talking about natural gas which is, of course, limited in its geographic extent, or are we also talking eventually about other fuels, like LPG or wood for rural areas? Different dynamics of how that might go about. And are we talking about this development of electrification via market forces or through programmatic efforts that intentionally subsidize or enhance -- enable customers to convert from natural gas to electricity?

Another dimension here that we had to wrestle with is what are the various sources of GHG emissions and are we going to try to deal with anything other than just the direct combustion part?

So here are the four traditional ways of identifying GHG emissions. Of course, direct combustion, refrigerant leakage from various appliances that have compressors, fugitive emissions, and that, of course, can be described in certain -- in a variety of fashion, as the local distribution level. The bulk gas transmission system, or even expanding all the way up to the production level. And then incomplete combustion, some controversy at the last workshop we had on these subjects about the extent to which incomplete combustion, you know, is actually incomplete combustion of methane, like in the cooking process, versus inherent emissions from the food that's being cooked.

So these are all, except for direct fuel combustion, the other three of these are fuzzier. And best as we can understand from the CARB inventory, all of the three together are not nearly as big as the direct combustion part, and so that was the focus for this study.

So let me talk now about the design of the scenarios.

So the first thing to keep in mind is that there actually is quite a variety of natural gas usage across the state, different emphases. So there will be several charts here where I'm actually displaying the staff's baseline gas demand forecast and the relative importance of different end uses because that will end up being important to the results.

It doesn't so much matter from a GHG perspective whether we're displacing space heating combustion in Northern California or

Southern California. But it makes a big difference to the electricity load provider and to, perhaps, even the transmission system where that takes place. And as Edison's representative said earlier today, these are issues that may, you know, become important, even down at the distribution system level.

So here in PG&E, if you look at the rightmost column, it's the percent that all these 12 or so end uses are of the total. Forty percent of all the residential and commercial building use of gas is in central space heating. And 17 percent are associated with water heating. Commercial is very much lower, none of them hitting ten percent or more.

Same sort of chart, this being for the SCE part of the Southern California Gas service area. And as I said before, we are looking at these results at the electric service area level because that's where the electric load is going to be and the impacts on the electricity resource and procurement process. You can see right off the bat that the space heating is a much lower percentage. Water heating is about the same. And the commercial sector end uses are rising in relative importance as the residential part is lower.

Similar story for San Diego space heating --

VICE CHAIR SCOTT: Hey, Mike --

MR. JASKE: -- is even smaller.

VICE CHAIR SCOTT: -- just a quick question for you, Mike, back on that previous slide. Oh, I'm over here.

MR. JASKE: Yes, ma'am.

VICE CHAIR SCOTT: All the way at the bottom, the commercial miscellaneous is actually pretty high, 13 percent. What types of things are included in that miscellaneous category? Do you have a sense of that?

MR. JASKE: Oh, there is a whole raft of things there. Commercial laundries. There's actually certain processes that may not even have an electricity analog and so, at least given current technologies, you know, aren't even capable of being shifted from gas to electricity. So in colleges and other things there's a host of process applications that might fall into there.

So it's just a whole hodgepodge of things that don't fit into the usual end uses that we think of.

VICE CHAIR SCOTT: Thanks.

MR. JASKE: And as I was saying for San Diego, space heating load is an even -- residential space heating is an even smaller proportion. Everything else is sort of going up as that goes down. And now there's a number of commercial end uses that are relatively more important.

All of which is to say that there's a different situation in each of the major portions of the state and that the consequences of converting natural gas in these various locals is going to have different electricity consequences to the electricity supplier.

So just a quick summary, residential space and water heating are by far the largest of the gas end uses. There's a lot of differentiation in space heating, as I just have been emphasizing. Commercial is a hodgepodge of -- oh, commercial miscellaneous is a hodgepodge of specialized things. And overall then the four end uses of space and water heating in both the sectors are really the place to focus, and that was where we put our emphasis.

So let me now talk about certain aspects of how one would be going about developing scenarios that have to do with the fundamentals of how we would introduce electric technologies as a replacement for natural gas.

So in new construction, of course, there's the issue of whether or not new dwellings in either single family or multiple family are going to be 100 percent electric or are they going to be mostly electric but still allow natural gas cooking or pool heaters or other things, you know, that are of lesser importance?

And then in commercial, which are the building types that can be 100 percent electric? The typical strip shopping building with an office and a bunch of little retail stores that probably has packaged units on the roof, that's probably completely feasible to convert that kind of a building to electricity.

In other larger buildings, particularly office buildings and large, well, really, large commercial buildings of any type the internal loads are much, much more important. And therefore, it's unclear how weather sensitive they are and, you know, just a bunch of issues about how to deal with those kind of large built up buildings.

In retrofit there's a whole host of detailed issues about the performance of heat pumps on either the space heating or the water heating side. If we install them, what happens with other natural gas end uses? When heat pumps are installed in residential dwellings that haven't had air conditioning before, how much air conditioning load is added? Or if they've had room air conditioners and now you're giving them a central capability, how much will that be exercised? So that's a creation of a kind of service that actually hasn't been present before.

What proportion of older houses and commercial buildings require expensive electric service upgrades? You know, the whole panel box issue, how costly is that going to be? Can there be programmatic efforts that might, you know, create mechanisms to have that done in -- that kind of upgrade, when necessary, done in a fashion that's less expensive?

And then lastly, if we actually do create the intention, which isn't so clear that it's there yet, for a large scale fuel substitution, how should natural gas energy efficiency programs change while that electrification process is unfolding?

For example, should be continue incenting efficient natural gas appliances that have a relatively limited lifetime, like water heaters or space heaters, or should we be focusing on building shell kind of investments that have the benefit while that building is still fueled with natural gas but, eventually, if it's converted to electricity will have ongoing electricity benefits? So those are issues that we'll eventually have to get to and that are in the background.

Now AB 3232 is an important effort that the legislature has set before the Energy Commission. In assessing the implications of 40 percent load reduction relative to 1990 is, obviously, sort of on the massive scale of retrofit. But there are a number of interpretation issues that we are going to have to wrestle with in the formal AB 3232 process and that I also had to deal with in devising sort of a simplified version for this project.

So this chart has bars representing

different years, 1990, 2016, and then two versions of 2030, the third bar from the left being the sort of counterfactual or baseline forecast, and then the one on the right being the compliance with the AB 3232 goal. And the question, really, or what's depicted here is the distinction between how much natural gas we're talking about displacing. The left-hand bracket with the words "40 percent below 1990" is clearly the simple reading of AB 3232. But if we also have to displace all of the load growth that's shown between 1990 and 2030, there's a much larger amount of natural gas that's being displaced and, therefore, a much larger amount of electricity load being added.

So for purposes of this study, this interpretation was used, namely that we're displacing all the load so that load is down to 40 percent below 1990 levels.

Now there's a second issue of interpretation of 3232. And I don't want to say that this is how the formal 3232 process will unfold over time, but this chart shows, in the righthand -- excuse me, left-hand side of the chart, all the same bars, and the red line showing 40 percent reduction down to 1990. But it also has an additional bar on the far right which is the issue of is it the total of direct combustion emissions from natural gas and the incremental electric generation emissions that has to be 40 percent below? And if that is the case, then, obviously, that means there's even more electric -- natural gas that has to be displaced at the end use level to make room for the electric generation penalty.

For purposes of doing this load assessment, I did not use the righthand side interpretation because I really didn't know at the outset how big that electric generation penalty was going to be. And subsequently, System Assessment Office has conducted a study. As I said, they'll be talking about that in the workshop at the end of October. So now we have an idea of what that red bar will look like and we can sort of iterate back and forth. But at the outset of this, that wasn't feasible, so I did not take that into account.

So after all this explanation of various factors, here are the five scenarios that I devised and assessed, so two of them having to do with how 2019 Title 24 Building Standards and other things affecting new construction play out, so one scenario starting in 2020 and rising to 15 percent by 2030. And what I mean by 15 percent is the share of new construction that is electric space and water heating.

So it starts at a low level in 2020. And that marginal share is rising year by year, so that by the time we get to 2030, it's 15 percent. And then a similar scenario, except that it rises faster and gets to the higher level of 25 percent by 2030. So this can be thought of as responding to the change in building standard requirements, the prohibition on new natural gas hookups that a number of cities have enacted over the last six or eight months, and similar forces.

Then there's two scenarios that are retrofit oriented, displacing residential space and water heating, starting at a low level in 2020 and then rising up to 15 -- excuse me, 10 percent by 2030.

And then a similar scenario at a higher endpoint, rising up to 25 percent. So in this case, to be clear, taking all of that space heating and water heating consumption that would have been the case in 2030 in the staff's baseline forecast and converting 25 percent of that to electricity.

And then a simplified AB 3232 scenario that uses the 40 percent reduction from 1990 by 2030 but not with the additional, call it, penalty or allowing for the incremental electric generation load.

And then finally, one more detail that's applicable to all of these scenarios is the issue of how the additional electricity load is satisfied. So, obviously, electric -- natural gas is displaced, adds electric load. But the question is: Can some of that load be supplied behind the meter with PV and/or battery storage system in some hours of the day and then whatever those systems couldn't do are supplied by the grid? Or is all of the increment supplied by the grid and relieved to another phase to sort of decide what's the optimal supply strategy?

For purposes of this study, I decided not to deal with the behind-the-meter issues and just focus on sort of the gross electric load and let this question of behind-the-meter sourcing be addressed in another study.

So after all that, here are the five scenarios listed out in sort of shorthand. And then the amount of natural gas displaced in million therms and the electricity added in gigawatt hours. And these just so happen to be in the same order that I laid them out in the previous slide. So the two new construction scenarios, and there is an error here on line one for scenario one, it should say 15 percent, not 10 percent. My apologies.

And so starting with that one scenario, those are relatively modest amounts of natural gas and electricity added. As you go down through these scenarios, they start ramping up to bigger and bigger consequences, so that by the time you get down to the simplified AB 3232 scenario, we're talking about major displacement of gas and major addition of electricity.

To give you a sense of proportion, that 3,800 million therms is about one-third of the residential and commercial natural gas baseline forecast. And that electricity added is in the ballpark of 10 to 15 percent of the total electricity load in the staff's baseline forecast.

So that's the annual energy result of the analysis. There are number of issues that still remain to be resolved. And I'm going to go through those and, to some extent, I may be able to make some progress on these and report sort of refined results in December.

COMMISSIONER MCALLISTER: Hey, Mike --

MR. JASKE: I hope that's the case.

COMMISSIONER MCALLISTER: -- can I ask a quick question?

MR. JASKE: Yes, you may.

COMMISSIONER MCALLISTER: So have you mapped any of these scenarios onto sort of different possibilities of what's happening at the local level?

You know, we're seeing so much interest in local government. You know, sort of Berkeley started the ball rolling, but now we've got San Jose having the discussion. You know, sort of what percentage of the population? You know, you could think about scenarios about what percentage of population is going to be under kind of a local stretch code that really encourages electrification by 2025, 2030, and maybe just sort of comparing and contrasting different scenarios and matching them up to your numbers here?

MR. JASKE: I think that that’s ultimately feasible. But since I’m starting from the staff’s natural gas end use forecast, which is only --

COMMISSIONER MCALLISTER: Yeah.

MR. JASKE: -- geographically as refined as forecast zones, it would take an extra step to sort of try to figure out, you know, how much gas is being burned in Berkeley.

COMMISSIONER MCALLISTER: Yeah.

MR. JASKE: Now we may be able to tease that out of QFER data in sort of a rough share --

COMMISSIONER MCALLISTER: Okay.

MR. JASKE: -- but it would be rough.

COMMISSIONER MCALLISTER: Yeah. I mean, if a few big jurisdictions do it, it could move the needle. Right.

MR. JASKE: Yeah. And then I’m not so sure whether the load profiles that we have, you know, are refined enough to actually represent also the pattern of load in that small a geographic area. We just don’t have that kind of load profile data at this point.

So non-combustion emissions, as I said earlier, we're not dealing with any of these three. Certainly, the AB 3232 project is going to tackle all of these to some degree. And I don't think, in the two months before the realized forecast workshop, that I can make any progress on these.

Where there are larger issues and that we may be able to make some progress is in the area of hourly load profiles. So, clearly, we want a tool that translates these annual energy -- well, annual electricity load increases into hourly load impacts, critical for a supply-side study.

So part of this project investigated different sources of load profiles, starting with ones that SoCalGas used that, in fact, eventually I traced back to E3' IRP work. Then were profiles I found for the residential end uses at OpenEI. And then the staff's overall project to using the consulting firm ADM to develop load profiles for the Helm (phonetic) model ended up being the best source that was most comprehensive and modern that I could find. So the majority of load profiles in this study come from ADM.

There are other potential sources. And

this is, obviously, an important area that will motivate us to work with utilities or consultants to come up with the best ones we can. Certainly, we can use building simulation models. The Energy Commission uses them a great deal, focused on Title 24 new construction, but not so much in analyzing retrofit applications and what -- there's a lot of diversity out there in different vintages of buildings and how they perform and what putting a modern heat pump in an old building shell might, you know, might look like. So there's a fruitful area of research there.

And then to the extent that there are energy efficiency (indiscernible) studies or going back to individual customer AMI (phonetic) data where we can be sure that it's an all-electric building, we can perhaps make use of that kind of data to help inform our load profile effort.

And, of course, load profiles on the space heating side are intimately connected to weather. And, obviously, duration and patterns of weather-induced profiles, you know, need to be brought to bear in this. And, unfortunately, they're not yet at the level that summer air conditioning is because electric space heating has been so overtly discouraged in California. So we have a lot of work to do yet to understand climate trends and weather events and try to tease out a convention that is similar to summer air conditioning peak for wintertime space heating.

COMMISSIONER MCALLISTER: Also, Mike, I would throw out there the equity concerns here. I mean, an older house with no insulation is going to not have as much flexibility in terms of hours of operation of heating and cooling, you know, because it's got to be on more and it can't coast through long periods. And so, you know, when we think about policies that help our citizens, you know, our residents adjust through this transition, we're going to have to think about, you know, relative -- you know, where we best put our investments. And that equity issue is one that's just going to not go. I mean, we really have to figure our solutions to where we're going to investment to help, you know, the 35 to 40 percent of low income get through this.

MR. JASKE: Absolutely correct. And there's such a diversity of residential housing condition and just the whole capability of it being modernized in a way that is cost effective for society and beneficial to the resident.

So there's a couple, a few charts I'm going to show here just to give you a sense of where we are at looking at this climate and weather issue.

So what's depicted on this chart are heating degree days for the three major electric IOUs. So for Edison and PG&E, there are actual multiple weather stations weighted together. For San Diego, not the case. And what's shown here are annual heating degree days from 1985 up through 2015. Obviously, I'm missing the last couple of recent years. This was the data set that was convenient and ready and ready at hand, but we'll add these more recent years.

And what is plotted in dotted lines, which probably the audience can't see, is the simple trend through those data.

And so when that dotted line is sloping downward, that means that there's a slight trend in climate as measured by heating degree days toward warming. And that actually is the case in all three of these. So there's a very gradual slight warming trend over these 30 years of data. Now that's not the only way that we want to understand weather, of course, because our space heating profiles and the peak of those space heating profiles are actually going to be responsive to individual events of cold weather, not just annual averages.

So what this chart is showing is, again, using the same data set from 1985 to 2015, we're looking at the most severe heating degree event, which is a three-day weighted average, again, in each of the major utility service areas. I guess in this case, I've added SMUD and LADWP. And here you don't see that kind of downward trend. In fact, the Southern California utilities at the bottom, which are warmer than SMUD and PG&E at the top, there may even be a slight upward trend in the last 20 years for the most severe three-day event.

So that's a form of weather analysis that we need to pursue in more depth and really understand how to make use of these data in devising sort of a typical winter peak-type condition.

Just to illustrate even more, you know,

the severity of individual weather events, this chart is constructed from the same daily heating degree data. It chooses the worst month out of that whole period for each of the three IOU service areas. It shows, on a daily basis, what the heating degree days were for that worst month.

There's a dashed line that shows the average December heating degree days across the entire 31-year period for PG&E and Edison. And what this shows, that even in the worst month, on the first ten days or so of that month both Southern California and Northern California had weather that was average to below average in terms of heating degree days, essentially, warmer than average. Then there's a period of a week or so in there where they're both about average or slightly above. And then this huge spike that happens on the 22nd of December for both PG&E and Edison. And that's spike is, you know, more than -- something like two-and-a-half times the average of the month, so it gives you an idea how much fluctuation can happen.

And what is most important is that PG&E and Edison are coincident in this worst weather event. And San Diego, down at the bottom in grey, although that wasn't the worst day for San Diego in the entire 31-year history, it's like the second or third worst day. And so it is, essentially, spiking at the same time as PG&E and Edison. And all three of them then would combine at loads within the ISO. So this is a coincidence issue that is something we try to deal with on the usual summer peak-oriented analysis that we've been doing for years that we need to get into, in greater detail, for these space heating loads.

So let me just wrap up here the overview of the initial results. So, obviously, winter incremental hourly load results are very sensitive to these space heating profiles. All those sources of profiles that I mentioned about halfway through this presentation used a different method of selecting weather. Most of them are building simulation result oriented as opposed to actual real data. We need to do much more work, as I've just explained, about alternative weather years so that we understand the sort of probabilistic aspects of this load to guide system planning, resource choice, and operations.

And I should say, you know, not just in passing but that there are, actually, significant incremental loads in the summertime that I saw in the preliminary analysis, not nearly as important as wintertime. But, simply, those water heating and the more secondary natural gas end uses, if you electrify some of them, you actually do get significant summer load increases. And I will show all these results in more detail with a lot of charts showing hourly impacts in the December IEPR workshop.

Just to remind you the limitations of this study, we only assessed fuel combustion. But, obviously, CO2 is not the only source of GHG emissions. We're not doing any cost effectiveness analysis to devise these scenarios and the penetrations of technologies. They merely assume this level of penetration. What are the consequences?

The load profiles haven't been customized to expected heat pump performance. That's one of the big limitations of the existing library of hourly profiles.

And finally and not the least important

point to make is that Staff believes that these scenario projections are too uncertain to include in official Energy Commission managed demand forecasts, but they're important enough to be published and to enable comment and further development. So what we're essentially going to be doing is excluding any of this, except for a limited amount of new construction from our AAEE scenario definitions. But we will be packaging this up and publishing it, you know, in parallel to the revised forecast so that people can have access to it and we can sort of collectively move forward.

And I think I've mostly said all these things that I'm trying to do in the next couple months.

Are there any questions?

COMMISSIONER MCALLISTER: I guess I would just make a comment, I mean, I think.

So your point, your last point there, is taken that there's a lot of uncertainty here. You know, we're at the front end of a lot of things, you know, not the least, EVs. You know, they're sort of on the hockey stick at some level. We know they're going up but we don't know exactly what that looks like, and even, you know, more so for building electrification and building flexibility with the storage, you know, uptake. All those things are highly uncertain.

But we don't like work pretty hard to narrow those uncertainty bands here in the next, you know, as soon as -- ASAP, really, we're going to end up overinvesting in the distribution grid in a way that, you know, we maybe don't have to.

So I just want to just highlight the urgency here for getting stakeholders involved, for doing some scenario analysis, looking at -- you know, our R&D Division is highly engaged here on some detailed studies on the electric side, the gas side. But it's definitely going to take a lot of people rolling up their sleeves and informing us so that you can do the best analysis possible and get a handle on this because it really has huge implications for the electric grid.

MR. JASKE: Yes. And you'll see those huge implications in spades in December.

COMMISSIONER MCALLISTER: Yeah. And, you know, I'm sort of on the edge of my seat, like as you quantify what the investment in buildings, say, you know, what that's scale is going to be for certain scenarios of electrification, you know, upgrade of existing buildings, particularly, as I said, focused on low income where probably the urgency of some kind of state involvement is highest. Those numbers are going to be large. And the questions is kind of how large and how we can grapple with them?

So anyway, I appreciate all the effort because this is new territory that's really exciting, but it's also, you know, kind of, I think, making us all straighten up our posture a little bit as we engage with it.

So thanks, Mike.

VICE CHAIR SCOTT: Thank you.

Okay, next we'll have additional achievable energy efficiency scenario design.

MS. NEUMAN: Hello. My name is Ingrid Neuman. I'm also with the Demand Analysis Office. AAEE isn't so much an emerging topic but we did want to actually present our preliminary definitions for the AAEE, or additional achievable energy efficiency scenarios, to you, so this was our opportunity to do so, so let's go into that.

So we are -- our process overview diagram here, we have various data streams that we get these energy efficiency savings streams from. The first one would be the 2017 CMUA Potential and Goals Study. This is for the POU projections. This is done every four years. That's why the 2017 date is there. That is the most current study.

Then another large source of data for efficiency savings come from the IOU projections. That's from the 2020 CPUC Potential and Goals Study.

And then lastly, we have our own Energy Commission Beyond Utility Programs which allow scenario designs for beyond utility AAEE projections.

So those are first-year projections. The other ones we take as cumulative projections, so they do include the decay and re-participation assumptions by those entities. We do some further scenario design around those but we try to go with the reference case.

For the POUs, there is only one case submitted, so we tried to make a more conservative picture, as well, of those efficiency savings, as well as more optimistic scenarios. For the CPUC study, you might be familiar with the scenarios that I presented there. And there is one case that's chosen as the goal for the IOUs then. And we work around that scenario, then, to create our own scenario definitions. And we can design the Beyond Utility as from conservative to aggressive or optimistic scenarios as well.

So then we merge those three. But before we do that, there is this little double arrow there between the IOU projections and our own Beyond Utility projections. And that's supposed to indicate the interaction that we have for codes and standards; right? The IOUs do take some credit for their involvement, their advocacy work, for codes and standards in the form of attributable savings.

And we also model Title 24, the Building Standards Title 20 and the Federal Application Standards in the Beyond Utility workbooks. So we do have to decide where we're taking those savings' data from. With the Beyond Utility workbooks, we're able to include some future code cycles that are not covered in the PG Study itself, but we certainly want to make sure that we count things once and only once.

So then we need to merge all those sources of data to get total cumulative AAEE projections for each year of the ten-year forecast. These are annual projections by utility, sector, end use and scenario. We have six scenarios for the 2019 IEPR cycle, similar to what we had for the 2017 IEPR cycle.

Then AAEE really is an hourly load modifier, so it goes into the managed demand forecast. So we have our own hourly tool that gives total 8760 hourly AAEE projects with the same level of disaggregation for all ten years of the forecast period.

We've added some capability now to do this by forecast zone or by TAC, you know, based on stakeholder requests, so -- but at least we have that level of disaggregation here.

So speaking of those four data streams, rather than showing you all of them at once, well, they are kind of there underneath, right, but we have on the blue, kind of the blue shaded on top, the IOU potential program savings. Then on the very bottom we have the POU potential program savings. Then in the pink we have codes and standards savings which are going to be derived from both the IOU PG Study, as well as from our own work in the Beyond Utility workbooks. And then we have Beyond Utility programs that only live in those Beyond Utility workbooks. So let's dive deeper into that.

Before we do, I did say something about overlap, so I tried to give some kind of conceptual view of what that might mean. You might be able to see -- oh, the mouse doesn't show up so well either -- so you might be able to see the timeline where it starts from 2020 to 2030; right? Because for our demand forecast, that rolls forward, and it's always about ten years that we're looking at, so we don't want any committed savings which also could come from those data streams.

So the first thing we would do is eliminate duplication with the baseline forecast because those committed savings would be going to that baseline forecast. And then we need to eliminate any other duplication between saving streams, which mostly boils down to codes and standards overlaps. So we definitely are cognizant of that and make sure to take those items out line by line.

All right, so going into the IOU AAEE scenario design, we start around the reference case. So the titles on the top for the six scenarios, they, you know, start with high-low, mid-low, mid-mid. So the first one refers to the IEPR demand kind of case. And then the second one is the savings case. So we take what the CPUC has voted on, as far as IOU goals from the Potential and Goals Study, we take that scenario and we make that our mid case or mid-mid or scenario three.

We have various levers then over here that we could work with to modify and make more conservative or more optimistic scenarios, so conservative being the scenarios one and two, more optimistic being four, five and six as being the most optimistic that we think is reasonably expected to occur in a very, very rosy world.

And we look at a sensitivity analysis for those various levers, first within the rebate and financing programs, so those are boxed here with -- and those levers interact with each other, so we do have to look at them as a package so we can modify incentive levels, look at the cost effectiveness measure screening thresholds. We do use the TRC cost effectiveness test for all the scenarios because that's the CPUC uses. And we discuss with them as far as what kind of cost effectiveness thresholds would be appropriate, even for our most optimistic scenario.

And then you can look at marketing and outreach, the financing programs, the low-income-specific programs and see if we go from a reference level or if we do a little bit more -- or I should say if the IOUs do more outreach, you know, how much more market penetration can they get for those programs?

Then separately, there is the model for the AIMS, so that's agricultural, industrial and mining sector, and it's the emerging technologies in those sectors. So that's a separate model where there are two options, an aggressive option or kind of a reference option. And then we can take an average to make it three options.

And then the similar type of approach is used for the BROS, so that's the behavioral retro commissioning and operational savings programs.

And these are then the scenarios that we have designed and that we are using in order to run our preliminary numbers. So we've just started working on those.

So you can see under scenarios one and two, we have kept the reference case for the AIMS emerging technologies, as well as for the BROS assumptions. Then for the scenarios four and five, we've taken the averages between the reference and aggressive assumptions. And then for our very most optimistic scenario six, we've gone for the aggressive for the AIMS emerging technologies, as well as the behavioral retro commissioning and operational savings programs' assumptions.

For the rebate and financing programs, which are that middle bar, we did manipulate the cost effectiveness levels. We worked around the threshold set at one for the goals.

So previously the CPUC, in 2017, they had voted on a cost effectiveness threshold of 0.85. And then this cycle, it's higher, at one. So they and we felt comfortable dropping it to 0.85 for scenarios four and five, but only down to 0.65 rather than 0.5 in scenario six. And folks were also adamant as far as staying with that TRC cost effectiveness metric, so we've used that across all of the scenarios here. For the more conservative scenario, we raised the cost effectiveness threshold to 1.2.

Then for incentive levels, we worked around the reference level -- reference cap of 50 percent of incremental cost and, based off the sensitivity, worked both to make more conservative estimates, as well as more aggressive estimates.

For the marketing, outreach and the financing programs, we kept a reference, right, the default calibrated value for the first three scenarios. And then for scenarios four, five and six, we considered what happened if the IOUs actually put some more effort into marketing and had, therefore, more market penetration.

So the low-income study used a different model this time and there was a lot of controversy about that. And so we were strongly encouraged to stay with what was adopted for the goals there. And we kept the same scenario across the board for our six scenarios here.

So again, our goal was to work around

what the reference -- what the goal was chosen by the IOUs for their program savings, so we made that our mid case. And then we worked to make it more conservative and more aggressive on either side.

So we used the same approach then for the POU AAEE scenario design. This is a significant improvement from what we had in the 2017 IEPR cycle. The POUs only submit one case of savings for their program savings and so we call that the reference case. And we had a contractual effort to actually use the model, the CMUA's model, to design more conservative and more optimistic scenarios around that this time, rather than just using one, the one case that's submitted for all of our six scenarios for POU program savings.

So we -- the levers we have are an expanded measure list. So we applied expanded measures to the more optimistic scenarios. Then we could change the incentive levels and the amount of outreach and marketing that's done, like for promotional expenditures. We could remove or add behavioral programs. And we could add the early retirement of programs.

So the potential savings, so this was

done of the largest 16, sorry, POUs, those are the IRP POUs. And then the other 23 small POUs were extrapolated from the potential savings of those 16 IRP POUs. The decision was made for the savings to be uniformly scaled by applying IOU rather than POU re-participation rates and net-to-gross ratios. And the reason for that is because those vary dramatically from one POU to the other and we wanted to have a uniform scale to measure all of this against. This does result in the saving estimates for POU programs being more conservative than they might be otherwise, so let's look at those definitions.

We kept the reference case, right, for the measure lists and the early retirement programs and we simply added for the more optimistic scenarios four, five and six. We added new measures and we implemented early retirement programs for the more optimistic scenarios.

Then for incentive levels and promotional expenditures, we decremented that by 25 percent for scenarios 1 and 2. And we were able to increase that by 25 percent for the promotional expenditures to get more program participants.

Then I mentioned the net-to-gross ratios. I mean, those did vary very much. Some had a net-to-gross ratio of one, others were down by some measures at 0.23, so we wanted something uniform there.

And then the re-participation rates were chosen to be the same as the IOUs where the re-participation rates are the same as the participation rates for new customers.

So moving on into the codes and standards data stream and the scenario design around that, we did start from the scenario chosen by the CPUC in the IOU Potential and Goals Study because, like I said, they do model a significant amount of codes and standards savings there. So we used that as a benchmark, made that our mid-mid or our scenario three. We have a reference case of compliance, code cycles through 2022 for nonresidential new construction and additions and alterations. And 2022 residential additions and alterations, the assumption is that the savings to be gained by future residential Title 24 code cycles would be small since we’re so close to ZNE with the 2019 Title 24 standards that will go into effect next year.

And then for Title 20, those are the California Application Standards, we have the reference case, as well as selected standards that are on the books through 2022.

And then for the federal standards, same thing, has selected standards here with excluding the 2020 general service LMPS (phonetic) and including the 2026 water source heat pumps.

So we do take the -- okay, so I mentioned a lot of this already. All right.

So the savings from the Title 24 code cycles are actually not taken then from the PG Study because we have more disaggregated savings and future code cycles available in our Beyond Utility analysis, so that's our Energy Commission Beyond Utility analysis. But we do build around that case, so we, you know, include through 2022 for non-res new construction and addition and alterations as far as residential additions and alterations.

So we took that reference case for scenarios two through four. There is a difference between the compliance rates that are chosen. So if you look at the line slightly above that, for scenario two you see a 20 percent compliance rate reduction, and that means exactly what it is. So if you had, you know, 85 percent compliance in the reference, then it would be 20 percent less in scenario two.

So then for scenarios four through six, the compliance rate enhancements, those are actually increasing from whatever the reference case is to either 95 percent for Title 24, so over a six-year period, so starting from the date of implementation and then six years thereafter. And that's supposed to reflect, you know, building departments being more familiar with the standards and builders being more familiar with the standards and the compliance than slowly reaching almost 100 percent.

So in addition, for scenarios five and six, we used the same scope, meaning non-res new construction, as well as additions and alterations, and only residential additions and alterations, but this time through the 2025 standards. And then for the high plus, or scenario six, we did the same thing, but through the last code cycle that would be implemented in this demand forecast period, so that would be the 2028 code cycle that would show first-year savings in 2029. So all of this comes from our Beyond Utility analysis.

So for the Federal Appliance Standards, as well as the Title 20 Appliance Standards, so the California Application Standards, those are all -- those are modeled by measure, not, you know, by code cycle, per se. And we utilize both savings reported in the IOU PG Study for those, as well as additional measures analyzed in our Beyond Utility analysis. So those do not have overlap. We choose the measures that are modeled in the PG Study as they are. And then we have additional future code cycle -- I said code cycle -- future measures that might be implemented for the more optimistic scenarios.

So if you look at the Title 20 and the Federal Standards, you can see that for scenario one, the most conservative scenario, we don’t have any additional measures included beyond those that are currently existing. And so then there wouldn’t be anything in the AAEE forecast for that.

It’s a little bit more conservative for the Federal Standards because there is a backlog there and there’s more uncertainty about which measures might actually be adopted and implemented.

And then just as for the Title 24, we work around that reference case in scenario three and we add more measures using both the PG Study, as far as we can go with that, and the Beyond Utility workbooks for the scenarios four through six. So I've labeled it as far as where the data is coming from, you know, whether it's a PG Study or Beyond Utility workbooks. That's what the BUWB means.

So the measures used from the PG Study, this is important, were analyzed in a total savings mode, so not just the attributable savings due to outreach and advocacy work by the utilities but, actually, the total savings from those measures because we want to capture total statewide savings, not just a percentage thereof.

Then the additional appliance measures, as I mentioned, were modeled in the Beyond Utility analysis to yield statewide savings for those.

So then for the entire codes and standards savings, we needed to allocate those to each IOU, each of the 16 IRP POUs, and then the smaller POU groupings. So that's very important for these small POUs that are inside the CAISO planning areas. So the small POUs that are in the PG&E TAC, for example, and the small POUs that are in the SCE TAC.

Moving on to the remainder of our Beyond Utility analysis, we had a large contractual effort this cycle, this IEPR cycle, or in preparation for this IEPR cycle, if you will, to update an expand the Beyond Utility Program workbooks that were developed in 2017 -- or that were used in 2017. The workbooks vary in level of sophistication but they all have various savings parameters that can be adjusted. So I have a list of those workbooks on the righthand side there, excluding the codes and standards ones that we've already discussed.

Staff is able to design scenarios using low, mid and high IEPR economic and demographic drivers. And then inside the workbooks, we can define, we can use various parameters there specific to those programs to define conservative reference or aggressive savings estimates, and that's very particular to those programs. And then we can also have individual weights assigned for each of the Beyond Utility programs. So there's quite a bit of flexibility here for our internal tool.

So what we did for the preliminary definitions here for the 2019 AAEE is to break these programs up until buckets as far as how certain we are about the assumptions, or whatever else is used, or the data that's used in those program workbooks.

So for the top three, the Prop 39, the DGS energy retrofits and the ECAA financing, we're fairly certain about the savings that we can get and the funding that's going to be available for those programs, so those would be our most certain ones that we might want to then apply to all of our scenarios, all of our six AAEE scenarios.

Then we have the next batch where we know that there are going to be savings. We have historical data, you know, or pretty good estimates of what things might look like based off of pilot programs. But there's still some uncertainty, like for one of them, the financing was almost like seed financing initially and then it dropped off dramatically. So we have to decide what -- how many years of average would we take as far as projecting future financing? So it's slightly less certain there than the first three groups.

Then we have the next batch that would be based mostly on pilot programs or the savings, you know, is less certain there.

And then some of our new workbooks where we're looking at, for example, the agricultural and industrial sectors, where there aren't any existing programs and it's just an estimate of what could exist, so those would go into our more optimistic scenarios.

So, you know, like I said here, for the last -- you know, the least certain program workbooks, they're not included in the first five scenarios. They're only included in the sixth scenario. So then as we become more certain we do include a low estimate of savings in scenario five.

And then for the top half, we have those included across all of scenarios but we use a mid-case or a reference-type assumption here for the most certain Prop 39 DGS energy retrofit and ECAA financing because those are established programs with historical performance data and expected future funding allocations. And then we use a high version of those savings for the fifth and sixth scenario.

We used three different -- the full three variations that we can have for the slightly less certain second batch there, starting with the GGRF Water Energy Grant.

So we, again, our goal was to create scenarios that are feasible in some realistic case, building around our reference. Here we don't have a reference; right? This is more based off of what data we have available and how certain we feel about that data. But we do want to have savings cases that range all the way from being rather conservative to being rather optimistic, which is what our sixth scenario is.

So this is everything in its full glory. And that's why I wanted to parse that out a little bit. So we did build around here for the IOU program savings. We did build around that reference case that was adopted for the -- by the CPUC for the IOU goals, so that's for the program savings there.

Similarly, we built around the reference case for POU program savings here in what was submitted in their 2017 CMUA report.

And then we did start with that reference case here for our codes and standards data stream but we took some of that data from another -- from our own sources for Title 24, for example, because that was more disaggregated.

So then we, of course, have the Beyond Utility, the remaining Beyond Utility programs that we worked with. And we have the four data streams that are all merged for these six AAEE scenarios.

So in summary, these AAEE scenarios really are conceptually similar to those implemented in the 2017 IEPR. The main improvement for this IEPR cycle is the analysis of those various energy efficiency savings streams. We've made very certain to avoid any duplication. We filled in some gaps, making sure that we are looking at all of the savings streams, even though not all of the measures are included in every scenario. But everything that was reasonably possible was included in the most optimistic scenario six.

So we also have significant software

improvements in the tools that we're using to analyze this data and aggregate this data. And it also allows us a greater scenario design capability, first and foremost, reducing manual processing; right? It gives us more time to do other things. And more rapid implementation, which I'm hoping for as I'm cranking out the numbers.

So we have an internal deadline for our AAEE hourly projections. So once I have the annual savings, I need to run them through our hourly tool and hand them off to the forecasting staff. And there will be some vetting, and that's why we're still calling these preliminary definitions because, depending on how those numbers come out, we might make some additional tweaks.

We are tentatively planning on presenting those results at the DAWG meeting scheduled November 21st, that's the Demand Analysis Working Group. There is a website that is linked. I've heard that sometimes it's hard to find but I can email to you if you need to find that.

And then, ultimately, this will be presented December 2nd at the Revised Electricity and Natural Gas Forecast IEPR workshop.

So thank you.

COMMISSIONER MCALLISTER: Yeah.

VICE CHAIR SCOTT: Oh, okay.

COMMISSIONER MCALLISTER: So I've gotten multiple briefings on this and understand how detailed this work is. And thanks, Ingrid, for all the great work.

I guess, you know, maybe just to put it in a longer term perspective, as we increase and improve our data resources and the tools kind of to manipulate large data sets, you know, and develop load shapes and really look at this more, really more completely, we'll be able to kind of get away from some of these legacy tools and move into something that's really completely adequate for looking at scenarios on the demand side and AAEE and flexibility and kind of integrate these discussions in a way that I think we really have to.

So we're a little bit in an interim phase right now, I would say, and really appreciate sort of your, you know, helping keep the vehicle repaired and moving forward while we're trying to sort of, you know, build the new one alongside of it.

But anyway, I don’t have any specific questions. Thanks a lot.

MS. NEUMAN: Thank you.

COMMISSIONER MCALLISTER: And also, did we have any blue cards, or is anybody -- no? Okay. I see some smart people in the room but I guess they’re just listening.

VICE CHAIR SCOTT: Okay. And with that, we will now go into our lunch breaks. We’re just a couple minutes ahead. Do we want to hold up lunch until 1:20 or just come on back at 1:30? Okay, 1:30 is great, so we are going to take a lunch break and we will back, ready to start again, at 1:30. See you all then.

Thank you to all of our terrific morning presenters.

(Off the record 12:20 p.m.)

(On the record at 1:33 p.m.)

VICE CHAIR SCOTT: Okay, welcome back from lunch, everybody. We are ready to get going with our afternoon session.

So let me ask our folks who are going to speak about transportation, forecasting the future of mobility to come on up and we’ll go from there.

MS. RAITT: It's Elliot Martin.

VICE CHAIR SCOTT: Yes. Thank you.

MR. MARTIN: Hi. So thank you for having me. Today, I'll be speaking a bit about considerations on VMT and emissions from new mobility systems and other technologies, spanning both technologies that we consider sort of that forefront of shared mobility, also touching a little bit on sort of what technologies are available today for freight, discussing a little bit how we measure VMT, how we would consider to evaluate VMT from the perspective of some systems for TNCs.

Also, as part of this presentation, I do want to discuss some examples of TNC integrations with public transit. There's a lot of evaluation and research on sort of how TNCs impact behavior, what they do for public transit ridership. But here are actually a number of pilot programs out there that also are directed integrations and connections with public transit. And those are generally, right now, operating in pilot states, but some of them have actually been operational for quite some time and have very -- you know, are implemented in a variety of different ways, so I'll discuss a few of those.

First of all, I'll just introduce what we all know about sort of the new and shared mobility systems today. Shared mobility and what has evolved from it really started in this country with car sharing, which is sort of old enough now to sort of not so much be considered new, but it has evolved. It was the first form. Roundtrip car sharing got established in 1998 in Portland. And then from there it grew nationwide and then, of course, evolved into different forms of mobility, one-way car sharing through a zone such as -- system such as car2go and ReachNow, which have since merged into a single system. And then also peer-to-peer car sharing. And these were sort of the foundations of shared mobility.

The quickly evolved into new modes that now are sort of proliferating all over the place. Bike sharing was the next level of evolution in that, starting with station-based bike sharing, which was established, interestingly, in Tulsa as the first system in North America. And then Washington D.C., Minnesota and other systems were sort of prominent early systems that then expanded across the country.

Of course, we all know about TNCs, the rise of Uber and Lyft. And basically bringing that shared asset to the consumer has widely proliferated the capacities of shared mobility to regions that otherwise couldn't have it with fixed asset systems, such as car sharing. And so there's been, of course, a huge rise in utilization of those.

And then some of the newer forms of microtransit, micromobility, are the next phases of evolution, not only in mode but in application. So microtransit operates very similarly, in some ways, to TNCs, but there are some caveats. First of all, microtransit usually defines a zone of operation where the start and end really can't leave that zone. The driver and the consumer both know that. And then there's also some other differences in terms of expectations of occupancy, and then also vehicle types that can be implemented. And I'll talk a bit about a few of those projects that are on the ground today.

And, of course, micromobility, the latest proliferation of e-scooters and e-bikes, this is the sort of evolution of dockless bike sharing that now has proliferated across many different systems. And there, of course, natural mobility and VMT implications from those.

And let's not forget public transit which is generally the system that we all want these systems to link to and operate efficiently with. And there are -- there's a lot of initiatives out there to try and advance that because it does take agency and industry coordination.

I do want to talk a bit, since this is about VMT, sort of what are the trends in VMT or what are we seeing in VMT at a national level. And then also to speak to about how we actually measure VMT. So these are the trends that we would see from the TVT (phonetic) reports from the FHWA. This is nationwide trends in VMT. You can see that in the late 20th century we had a pretty linear growth in VMT. And then when we hit the great recession, we had this decline. And then you can see sort of a flatlining of that trend. This is on the right here with the red line. This is growth in aggregate VMT as it is measured today.

This flattening of VMT from peak -- from sort of point to point is the longest stagnation in VMT that has ever been observed in this series, which goes back further than this trend line to 1971. It's never been this flat for this long. This was also a flattening that also occurred during an economic recovery.

So those two points lead us to sort of understand that this -- we may be entering into a period of different dynamics of VMT growth, where VMT growth is not necessarily coupled with the same level of economic activity that we saw in the late 20th century, that there are some distinctions here that could be occurring.

Now that said, we are at peak VMT. VMT has never, as it is measured in the series, has never been higher. It has since picked up. And when we look at VMT per person at the U.S. level, and this is just taking what we measure from this series and then dividing by estimates of the population of the U.S. Census, to be clear as to how this calculated, we do see that we're still not at what we had as far as peak VMT per capita at the nationwide level.

Now I do want to speak a little bit about the measure of this because, of course, our measure of VMT is a bit imperfect. We use the Highway Performance Measure System. And then we use counts from sensors across the country to basically track the wiggles of these movements. So we get a month-to-month measure of VMT, which is a 12-month look back, of the summation of VMT from month to month. So, for example, in September, we would add up all the way going back to October the previous year and then we would move that window down and sum up our monthly measures to get these values. That is informed by counts that come from sensors and detectors.

And then it's also updated frequently by what is our Highway Performance Measure System that the State of California and every other state also reports to. These reports are basically sort of average or average values of what is the overall traffic level that is on particular road links.

And I make this point to go into this detail to really make the point that VMT measure is somewhat of an imperfect science that we have. And so we talk a lot about VMT but there still is the need for us to understand VMT and to even get better data on how this is broken out. This is aggregate VMT. So when we're looking a measures, you know, counts from trucks and counts from cars are all added up into sort of this overall measure. And there is some level of classification to this. But nonetheless, we are drawing estimates of what this VMT is. And this is at least a continuous series of estimates that we can sort of make comparative measures against.

So how will mobility as a service change VMT? Well, of course, there are the obvious things. The travel behavior changes in public transit, walking, bicycling and other shared mobility shared in active modes and personal vehicle driving will all change as a result of these system because it's a new mode. It's effectively a new choice within your choice set that you can now take, so it will draw from everything. But it may also make you -- cause you to make other decisions or use other different types of fuels that will also impact emissions, and then also impact your decisions with vehicle ownership.

And that's the second point here. Changes in vehicle ownership is very, very important for VMT. Because once you lock in that vehicle ownership, you are, of course, committed, effectively, to driving that vehicle for some period of time, given the fact that you're lower -- you have this now low marginal cost of driving that you have available to you. So preventing vehicle ownership, and I'll talk a bit about that in a minute, is a very, very important effect of these types of systems. You may see a bunch of changes. But we also have to measure is what would have happened in this world where these systems didn't exist? What kind of assets would you have chosen to own?

There are some changes in fuel type. Of course, if some of these systems are electric or are using cleaner fuels, that's naturally an advantage, even though we may not perceive any difference in VMT.

We also have to be considerate of system vehicle activity, that is how many vehicle miles are being put on the road. For car sharing systems, it's just the utilization that we observe. But, of course, for TNCs there's all these -- there's all this circulating, there's what is the fetching of the passenger and the searching for the passengers, and even the travel to the market, and I'll speak to that in a bit.

And then there's also system logistical operations. This mostly applies to sort of the micromobility systems and bike sharing systems. There's a fair amount of energy use that's associated with rebalancing those systems with charging those vehicles. So those are also other considerations that we need to be able to measure in order to evaluate, what are these systems going to do to overall VMT?

I'd like to speak, too, a bit about sort of the main travel behavior components of TNC-VMT change, that is what does -- what do TNCs do to reduce VMT? What would we measure and consider to be a reduction as a result of the use of TNCs?

Well, of course, there is the change in personal vehicle miles traveled. If someone takes a TNC to a particular location and said they would have driven their own personal vehicle, then we don't want to just count that VMT as being part of TNCs because it was in a TNC. There is, of course, the extra circulating that does occur as a result. But if that trip would have occurred in an automobile anyway, then we're just counting it because it's in a TNC. We do want to consider the fact that there may be some personal vehicle substitution there. And that at least provides sort of somewhat of a credit in sort of what we're evaluating with respect to VMT change.

Then there are some other big effects, big personal vehicle shedding, which is the act of getting rid of a car. This car is too expensive. It is now retired. It is something that I don't need anymore because I have access to this shared mobility asset. We might see this in environments where, you know, other systems really aren't that accessible, and so TNCs bring that shared mobility; this is expensive to own, it's expensive to maintain, and I do want to get rid of it.

Back when shared mobility was a little bit younger we saw a lot of this. And we see some of this still now today but we see a lot less because people are growing up in these systems, they're already there. When the people were there and the systems came in, that's were a lot of the shedding -- when a lot of the shedding happened because people made this realization that they could now -- some people could adjust their assets. But we will see it on the order of, you know, two to five percent of a population may say that they shed a vehicle in our surveys. And they'll say, yes, I shed a vehicle and it was because of this particular system.

We also note personal vehicle suppression. This is a very, very important effect. It is the act of not buying a vehicle because the system is available. Just as we want to measure, what do people do and what are people doing that's different, we also want to measure, what do they not do? If you don't buy a vehicle then you are not going to drive that vehicle 4,000 to 5,000 miles per year. That's the average of what we see. We ask, well, how many miles would you have driven this vehicle if you hadn't purchased it? Well, it comes to about 4,000 to 5,000 miles a year. So, expectedly, it's not a lot. Of course, we know that that's less than the average driving than the typical American does. But for a vehicle that is suppressed that might be within reasonable expectations.

But if you're -- if you find that it's just not worth it to go out and put that asset out there -- to put out the capital outlay to get your personal vehicle, to acquire a personal vehicle, then you may -- you don't transition to all of those lifestyle changes that end up to increasing VMT. We do want to be able to measure that hypothetical difference as to what would have happened in the absence of this, well, because this is a relatively easy effect to do. It's not doing something. Even personal vehicle shedding requires some initiative by the consumer to get rid of a car, which can be, in itself, sort of a chore. But you just have to not do something and you get about the same amount of impact on VMT. And that's something that is important to realize.

And then finally there -- it's similar to sort of the change in personal vehicle miles traveled, we have the change in other shared use mode. If we see somebody driving in a TNC but they would have taken that trip in a taxi, then we're just counting it again because it's in a TNC. And so we do want to make that consideration that some of this substitution would have been in a personal vehicle driving anyway.

All of these are components that we would measure for VMT decline. But, of course, there are these major components of VMT increase. And this is basically the vehicle miles traveled that we have the system do. They're broken out into about -- into four different phases. And I think anyone who's taken a TNC is familiar with this. Period zero, which is sort of the travel of -- travel to the passenger market, there has been sort of anecdotal and even survey-based evidence that shows that, you know, some drivers, they drive some distance to get to their market and they do that commute pretty regularly, so that travel should be considered. It's actually not measured by the app so it has to be. By any sort of activity data, the operator-side apps aren't measuring that, so we have to measure that by sort of surveys and other methods.

And then there are other -- and then from period one to period two to period three, period one being open to passengers, looking for passengers, period two being fetching the passengers, going to them, being assigned, and period three all are recorded by activity data, if we can get it.

One thing about period one is that this -- you may have heard about the issue of double counting. So there are, of course you know that there are different operators that -- or drivers that will be driving with both Uber and Lyft open at the same time, so both of those operators are clocking those miles. So we want to have some estimate as to what is that degree of double counting if we're taking that information and putting it all together to assess, what is this relative level of driving? We don't know.

We've been doing a study on this impact on three markets. We've had this reviewed by external reviewers and reviewed by the operators, and we're releasing it soon, to evaluate sort of what we saw with respect to these impacts in three different markets, that is San Francisco, Los Angeles, and Washington D.C. And really, it's a function of the net effectiveness. It's that driving that we see sort of as the system is operating against all of these other behavioral changes that we observe.

So with that, we also want to ask questions about how can TNCs work with and complement transit? And are there case studies?

Numerous studies out there show that TNCs draw from public transit. That's a very, very expected result but it is something that raises a lot of concern in policy because, of course, we don't want to be replacing our public transit use with personal vehicle miles traveled. That's against our general goals from a policy perspective.

But there are examples of TNCs complementing transit through natural activities. So there are just people generally using it access transit. But there's also other supportive projects that have been in collaboration with public agencies. And building on lessons learned from these studies, TNCs, microtransit and other forms of shared mobility may be integrate and support public transit systems better.

One of the big examples of this I'll talk about is a project that we're evaluating an FTA Mobility on Demand MOD Sandbox. These are projects that involve testing new innovations with public transit agencies in carpooling, public transit connections, there's trip planning which I won't speak to, TNC and microtransit integrations, as well as other innovations. I'll speak mostly to the TNC and microtransit integrations that have occurred, as well as an interesting project more locally in the Bay Area on carpooling.

One example is sort of this first mile/last mile project with DART where DART, of course, is the rail system in Dallas, and they have regions that are very, very low density in sort of North Plano. And they have these systems that sort of circulate with the GoLink vans that circulate towards the -- at the end of these lines in Plano, Texas. And so I've been to Plano, I took the system, and you basically can plan out your trip while you're on the rail line, it takes about 20 minutes to get out there, and you can plan your trip. And then the vehicle will arrive and it will take you to anywhere you want to go within the Plano region. So the information systems are there and implementable on the transit side to make that work.

Now that's not a TNC. But this system also allows -- this is, of course, a wheelchair accessible vehicle, as you can see, but the system also allows you to sort of call an Uber pool. And as long as you're connecting to the DART rail transit, you get a special rate discounted for making that connection using a TNC, and that's a TNC program thing. So this project is under evaluation via the MOD Sandbox.

Another project that's also evaluated within the Sandbox is the Pierce Transit Project. And this in partnership with Lyft to do a very similar effects in different zones around the Tacoma region where Lyft can basically provide first-mile access -- first mile/last mile access to transit within the zones that are seen here at a special rate. And it's objectives are, of course, to reduce VMT, but also to reduce demand on parking at their impacted transit stations.

A big project that's both in California and in, also, the Seattle area is the L.A. to Puget Sound First Mile/Last Mile Project. And this in partnership with a microtransit operator called Via, which is -- which defines specific zones, and you can see the zones here on the maps. The map on the left is the Seattle region. And then the map on the right is one section of the L.A. Metro system.

So what microtransit does, as I was mentioning, is it defines these zones that you can connect -- you can call up your Via, which looks, in this case, in the Los Angeles case, it looks like a TNC. It basically is, you know, very similar. It's the same vehicle that could be driven in a TNC system. And you can call up Via and you can anywhere with this region. And if you're connecting to or from the transit system, then the ride is heavily discounted and, in some cases, free.

So this, you know, an example of how these types of formations of transit integration with TNCs and microtransit operators are starting to form and are starting to be implemented and practiced. There is, of course, front-end and back-end integration that is required for these connections but they are in practice and being tested right now.

I want to speak about the BART project because the BART project, we just recently submitted our evaluation for the -- to the USDOT and we've gotten comments back on this about this project, to not forget carpooling. So carpooling was a project, a MOD Sandbox, that used better technology to match people beforehand. One of the biggest challenges of carpooling is that if, you know, your carpool friend doesn't show up or isn't available that day, then you can't get into the HOV lane, or you have to schedule with them, you know, every day very, very rigorously, and that's hard for a lot of people. That's very difficult to do.

So this particular project implemented a matching system that allowed you to change that day by day. And the person that you would get matched with would change day by day. And you would carpool to a particular BART station. Most of them were at the end, so like Dublin-Pleasanton, the Antioch Station, the Warm Springs Fremont Station was a big station, as well, where you would carpool and travel to the station and you would get specialized parking the permit lot. So there was carpooling lots, they had legacy carpooling lots, but then you would go to the -- you'd get special parking in the permit lots and then you could park there, which that parking was off limits to carpoolers before. It helped with enforcement. It helped with, also, access to transit.

And based on the substitution -- now, of course, there's mode substitution that has to be considered here. So we have people who would have driven and then -- anyway. And so matching those two people puts two of those people into a single car. That's a VMT reduction.

Of course, we do have people who would have taken transit and now they're in a carpooling. Well, that's really helping much. It's not hurting because if the other person was going to drive anyway then, you know, it's almost a near-zero impact.

And then we have the nightmare scenario where we have two people who were going to transit say, hey, now we can carpool and let's match and let's go. That a VMT increase. We want to be able to measure sort of the balance of those effects. We did evaluate the balance of those effects and, generally, I have to say that they're positive.

So this is something where, you know, we don't want to forget the practice of carpooling and the connections to transit because this project did have a considerable amount of scale. And most of the activity was at the Dublin-

Pleasanton Bart Station. But we're talking on the order of, you know, thousands of trips.

I also want to point out a more local project that is presently underway is Via in West Sacramento. This is -- as you can see, there's a picture of the Via van. This is a microtransit operator that circulates and can be called anywhere within the West Sacramento Region and it can deliver you almost anywhere with the West Sacramento Region. It's near point-to-point. It's not quite point-to-point, unless there's a special request for point-to-point access if you have a specific disability. And it would run for a certain time period. It would connect you to transit.

It would not leave the City of West Sacramento, and that was one big thing that our surveys sort of pointed it out, people wanted it to go to, you know, key points in Sacramento. I believe that's an innovation that is being considered. But there are institutional issues with that. That's a different transit agency's operating area. And so there are things that need to be considered in coordination.

And this is where these private operators and these agencies collaborate to work out some of those institutional issues, and then also work out some of the technical issues, such as people being able to access -- people being able to report, hey, I can’t get to this point-to-point location because I’m in a wheelchair. And those types of things are very, very important to consider and they need to be worked out in pilot projects.

So this project is also very local and also underway. And you can notice here that just the vehicle type is different. So microtransit in the L.A. capacity was really, you know, a, you know, a Prius. This is a dedicated van of a specific type with a higher occupancy. And there is some expectation with microtransit that you are going to be circulating in a vehicle with a bit more higher occupancy.

I also want to point out another project down in Southern California, GoMonrovia, which is TNC with public transit through pricing. This is basically dedicated pricing points that are defined based on the ride, based on your destination, based on whether you’re pooling and whether you are connecting to transit. So if you travel anywhere within the GoMonrovia region, then -- and you just use a regular sort of -- if you just use a regular sort of classic ride, then you go at flat rate of $5.00. If it's a shared ride it's $2.50. These are heavily discounted. And if it's a shared ride to one of a key transit point, such as the Metro Line, then that's $0.50.

So this is a case of where just the integration of public transit is a matter of specialized pricing for particular zones that are defined. And the GoMonrovia is a good example is a good example of that type of integration that is being implemented today.

There are some evidence of broader impacts that I'll just speak to relatively briefly that we've evaluated in the context of shedding and suppression and how they've been translated to broader system impacts.

We do see evidence from one-way car sharing, so there are findings that, you know, we had. We found that between two to five percent of members, we studied five different cities, evaluated changes in behavior through surveys, we found that between two to five percent of members sold a vehicle due to car sharing. And these are questions that if we don't just to look to say, did you get rid of a vehicle, did you get rid of a vehicle and was it because of car sharing?

And when we ask these questions nowadays we really ask, you know, if this thing wasn't around would you have gotten this -- would you have still gotten rid of this vehicle or would you probably still have it? And they have -- and multiple questions have to be answered for us to sort of validate that that's a shed -- that that's, in fact, a shed vehicle. We want that attribution to the system to be able to count it.

We also found that seven to ten percent, depending on the city, of respondents did not acquire a vehicle due to car2go, so that's an important measure as well. That's that personal vehicle suppression component that I'm talking about. And it is always going to be higher than the shedding because it is, in fact, an impact that, again, is easier to do. It's about not doing something versus getting rid of a car.

And we did estimate that there were about 28,000 vehicles that, when you account for shedding and when you account for suppression, were removed across these five cities. And the five cities, just for completeness, were Washington D.C., San Diego, Seattle, Vancouver and Calgary. So we did sort of a North American study, as listed here. We did do sort of a percentage of reduction in VMT by car2go households. This was done by taking the before measures of VMT, the reported VMT, and then their after VMT as accounting for suppression and for shedding.

We've also seen that there are ways in which these systems can be manipulated based on incentives to do certain things.

So there was an all-electric one-way car sharing system in San Diego that operated for several years. And it was basically zonal. But they had a huge problem in the sense that they could not charge these vehicles locally. There wasn't enough charging infrastructure to charge vehicles in the city network. They were also, actually, a little bit reluctant to take up that charging and then to just keep it, you know, hold it or occupy it for long periods of time to, I guess, annoy or anger private vehicle owners who wanted to charge as well.

So they had an incentive program that

allowed people to basically get a bit of a credit from taking that vehicle from somewhere in the zone and then bringing it down into the central part of the zone to where they could then easily access it and bring it to their charging depot. And you can see here in this graph the charging incentive period. That's the lines that I've marked out. And where that green line is indicates the departure from natural activities.

So when we want to evaluate what are these systems doing in terms of incentive, we do need to take into account the fact that there's some level of natural activity that's occurring, but when we implement the pricing system, we're going to see a change in that. And that difference is the marginal impact of that system. It's a percentage of people who get their behavior adjusted. We did see that this credit, which was about ten minutes of driving time credit that was applied to their account, did make a move. And it allowed people to bring -- or enticed people to bring these vehicles closer. So pricing can be done to change how the system operates and improve its efficiency.

There's also questions about how will

micromobility impact VMT and, if so, how? Will it impact VMT? And micromobility travels may reduce their VMT through mode substitution. It might be pretty intuitive that, of course, if you're not -- whatever you're doing, if you're now on a scooter, you're not adding to VMT. Even if your shift is from a bus to a scooter, that's not the VMT that we're necessarily interested in.

But when we look at the system from the perspective of trip substitution we have to understand that those trip substitutions are generally short. So whatever the substitution is, whatever that trip is, it's going to be a mile, maybe a couple miles. With EVs, of course, the range is a little bit longer, but each trip is going to be relatively short. And EV-based system require energy input. And there is a whole lot of logistics that are involved in rebalancing those systems that is important to consider.

This is the one -- this -- I'm not sure whether this is necessarily going to bear out at all in the data for the evaluations that we're doing and that others are doing. But this is the one system where I could think it would be possible where VMT might fall and yet energy consumption doesn't change that much because the VMT is reduced but yet there's these larger vehicles that are aggregating and circulating these vehicles around. They consume a lot more energy. And then, of course, there's the energy input of plugging it in.

So generally speaking, VMT changes and energy changes are correlated. Micromobility may be one of the modes that's more exceptional in that it does -- it has more of a split between the impact on VMT and energy consumption.

There is a consideration of mode shift here. People are shifting from public transit to bicycling or to one of these micromobility systems. We have to understand what's being substituted -- is it a TNC trip, a personal vehicle trip, a personal or taxi trip? -- to understand sort of what those energy impacts are. We've done some calculations as to what that balance of mode shift needs to be and it needs to be a little bit north of ten percent as a mode shift to sort of, at least from the calculations that we had done, with one particular -- with one system.

So I don't want to make that too much of a generalized conclusion but I do want to say that it's not something where it's like, okay, well, you know, at least from our findings, it wasn't like it was just two percent. It was more than that was required to kind of get some level of balance between the energy consumption that we were seeing from logistical operations.

Really briefly here, these impacts are not the same, depending on where you are across the region. So this is an example of mode shift by where you are in Washington D.C. The red is sort of shift away from rail and the green is shift towards rail. It's hard to see, I can realize now, from this graph but there's a lot of red in Washington D.C. and there's a lot of red in downtown Washington D.C. That's where you're going to see a lot of mode shift away from transit.

On the periphery of Washington, we see relatively more access to transit, relatively more people saying, hey, I'm using rail more because of public transit -- I'm sorry, because of bike sharing.

And in Minneapolis, we saw a very

interesting result, is that most of the shift as a result of bike sharing was for transit, was to transit. And that, we hypothesize, is that you had a lower density environment. You also had a less intensive transit system, so there were just less ways in which you could substitute public transit using bike sharing. So in this city, in this particular environment, we saw that public transit was actually increasing as a result of the bike sharing system.

And we also saw similar result, actually, at a relatively small scale in Salt Lake City.

I'll just speak really briefly about, also, trucks because trends in diesel fuel, what do we do about trucks? This is what we've seen in trends in taxable diesel fuel in California. What's nice is maybe it's not increasing but it's certainly not decreasing. We do see that sort of seasonal pattern associated with agricultural movement and other summer movement that's occurring with your moving average. But this is the trend of what we see in diesel fuel and heavy trucks deal with diesel fuel.

You know, perhaps we're excited about electrification of these heavy-duty trucks but there's a lot of barriers to that, of course not just technological barriers but regulatory barriers. There's size and weight regulations that these trucks can only be so heavy. And so batteries naturally add to that weight and, therefore, lower the amount of stuff and amount of tonnage that can be carried by these trucks. So perhaps technological innovations will overcome that or there will be still the ability for these trucks to operate. I'm optimistic to that. But what can we do to address some of these?

Well, there is the idling of electrification. And this is a technology that has been in place for well over a decade, is truck stop electrification. And it has rolled out into several locations with California.

This picture above is a picture I took at Lodi, the Flying J in Lodi, of the shore power. One thing I did notice at the time was that it wasn't being used. And many of those pedestals, quite honestly, were not being used. There is a limitation here in the sense that trucks don't seem to very often connect to this pedestal to electrify their idling. Now that would displace hours and hours, sometimes days, because sometimes these truckers, they park there for days, where they're idling their vehicles. It's very, very hot there during the summer, of course, we all know. And they are idling during the day and night to power their internal amenities.

That component of idling, which consumes a lot of fuel, is something that can be electrified today with very, very limited modifications to trucks and very, very simple to acquire equipment. But utilization and infrastructure is more limited. These pedestals are only on the outside of the lot. They're not in the middle, so not even every truck, even if they want to use electrification, they've got to get to the right spot to get it. This is something that's very doable today, independent of whether we can really facilitate a larger shift in fuel use by trucks.

And then, of course, there is substitution by TNC -- by CNG, which is possible for long haul but, of course, it forces serious capital infrastructure costs. That's story really hasn't changed.

This is a map of truck parking that are actually in alternative fuels that we keep track of. It's a website called American Truck Parking. And truckers can search on it to sort of find truck parking. But one of the things that we added to this was alternative fuel stations, specifically for trucks that could be accessed 24 hours a day. Where are those stations?

We see that California is actually, through PG&E stations and other stations for school districts and such, has actually got a pretty good network of locations where you can fill up with CNGs, CNG, with our truck any truck. But then, of course, you see that big gap in Nevada, and there's other gaps in the other parts of the country that limit the application of this for sort of long-haul trucks. So it's still very much a prospect for local trucks within the state but it's also still -- but it is something that, at least within the state, is -- the infrastructure does exist for this.

And there are capital cost considerations for CNG vehicles as well. The trucks -- the freight system is sort of very, very focused on generalized costs. So those are important considerations but these are things that we can do contemporarily to potentially take some edge off of diesel fuel consumption.

So with that, I will wrap up and ask for -- answer any questions.

VICE CHAIR SCOTT: Great. This is very, very thorough and very interesting.

A question I have for you, so you know, we're looking at how we start really capturing some of these trends within our forecasting. And right now they are -- I feel like they're not -- they're not big enough that they show up in moving the needle.

Do you have a sense of how, I don't know, how much more shift we need within TNCs or how much more shift we need of people out of cars and more into transit for us to kind of start seeing that show up?

MR. MARTIN: I mean, the first thing I think that we're going to see, and we might be seeing it also in VMT, is lack of growth that would have otherwise occurred. That's going to be the first effect. So we're going to see these, you know, these trend lines go up, but they may not be going up as they would have gone up five years ago or ten years ago. That's the first thing that we want to look for, it's that VMT that did not happen.

Then we would look for the shift that, you know, would result from reductions, broader shedding, broader abilities of people to say this, you know, the personal vehicle asset is too expensive in this environment, I don't need to carry it anymore, this is much easier to do. I don't -- and that's going to be a question of, you know, system operations, it's going to be a question of pricing. Do TNC pricing and other microtransit really provide sort of a cost effective alternative for that? But we may be seeing -- I mean in the growth rates of VMT, we have seen sort of a kink in how those are growing.

Another thing that I would look to also to get a sense of that is vehicle registrations. And we do see vehicle registrations, particularly in the County of San Francisco, is on a decline. And vehicle registrations on a per capita basis are on a decline and they've been declining since about 2016. Now that's not a very long period but that's sort of in line with when TNCs really kind of exploded on the scene to become sort of part of the transportation nomenclature and sort of widely disseminated everywhere.

So you know, those differentiations in growth rate, I mean, I don't have a sense as to, okay, it's going to be ten percent adoption. And what does adoption mean? I mean, adoption from a TNC perspective, there's a frequency of use. When we do our studies, we balance frequency of use. So we know our surveys have people who are going to be more likely to be using it more. And if you're more likely to be using your system more, you're more likely to have an effect on it. You're more likely to have a suppression effect. So we do want to balance and re-weight our samples with the population data on frequency of use to more reflect what the population is saying.

So I think that the first thing to look for is that sort of change in growth rates which we, again, may be seeing, and looking for sort of what are the harbingers of that? I think registrations is an important harbinger, also, vehicle sales which have -- which peaked in 2016 and have leveled off a little bit, not much to sort of -- I think it's partially a function of saturation. Because when you look at the broader time series of vehicle sales, there are these periods of plateau that do occur when the market gets saturated, even in good economic times. And that has occurred right now.

COMMISSIONER MCALLISTER: I guess I'm wondering what the conversation is at the RTOs and MPOs on this. You know, they channel Caltrans money. They do local planning. They are really a key factor in all this --

MR. MARTIN: Yeah.

COMMISSIONER MCALLISTER: -- in directing policy at the regional level and implementation, you know?

MR. MARTIN: Um-hmm.

COMMISSIONER MCALLISTER: And are you finding that they are, you know, really engaged with this as part of their climate planning efforts, or they're looking for solutions or, you know, probably variable? I don't know. Are they -- what's their role in all this?

MR. MARTIN: You know, I don't know if I could comment on what the MPOs are saying, I mean, because that conversation with the MPOs that are happening I'm not necessarily directly connected to.

I will say that from what I've seen from projects that are implemented, and I mean, for example, the Scoop to Bart Project was one in which MTC was involved in. So they -- that was a project where you had MPO involvement and MPO consideration for and support in doing that project.

So I think that for some of these projects, you know, they're still looking at this from the pilot phase. I don't know, and maybe, I don't know if anybody's thinking about sort of any sort of broad scale of implementation. The projects that mentioned, you know, they're still experimental. The bugs are still being worked out as far as how these zones will work. You know, will they see, you know, general mode shift as a result of that? Will there be enough utilization to justify continuation? That's the stage at which the development is in. And I don't know whether that has resulted in other conversations within MPOs that I wouldn't be privy to.

VICE CHAIR SCOTT: All right. Yeah. Thank you very much. We appreciate you being here today.

MR. MARTIN: Sure. Thank you.

VICE CHAIR SCOTT: We will go to our next presentation which is by Caitlin Miller.

MS. MILLER: Okay. Great. Good afternoon. My name is Caitlin Miller and I work at the California Air Resources Board in the Sustainable Transportation and Communities Division. And today, I'll share with you a bit about how the state's climate policies interact with land use and transportation and what CARB is working on in that space.

So one of CARB's responsibilities is to identify how the state will address climate change through our Scoping Plan. The plan identifies how to reduce emissions from multiple sectors with transportation emissions serving as the largest source of these emissions. Not shown on this graph but were 50 percent of the emissions account for energy from transportation fuels, so that would be kind of transportation across sectors.

CARB's 2030 Scoping Plan identifies

reduction in growth of single-occupancy vehicle travel, as necessary, to achieve the statewide greenhouse gas emissions target of 40 percent below 1990 levels by 2030. Even more will be needed to achieve our 2045 carbon neutrality goal.

So how do we address transportation emissions?

This graphic illustrates many ways the Scoping Plan works to address transportation emissions through vehicles, fuels and activities. Some of these action include zero-emission vehicles, walkable and bikeable communities, land conservation, farmland protection, sustainable freight, affordable transit-oriented housing, infill development. And collectively, all of these actions work toward addressing emissions in communities. Actions for both light- and heavy-duty vehicles are needed to help address increasingly stringent air quality standards.

The two areas with the most critical air quality challenges include the South Coast Region and the San Joaquin Valley. The strategy to address these standards includes further reduction in growth of VMT, vehicle miles traveled, which we've been talking about, and through SB 375 and other complimentary efforts to reduce tailpipe emissions, as well as emissions from facilities that produce the fuels to power vehicles.

So this presentation today, though, will kind of focus more on what CARB is doing in the light-duty passenger vehicle with regard to light-duty passenger vehicle activity.

So SB 375 is one piece about how we address transportation emissions from light-duty vehicles. In 2008 the legislature passed SB 375, a landmark regional planning measure that requires metropolitan planning organizations, the MPOs, to adopt sustainable community strategies, or SCSs. And some of these strategies include expanding public transit systems or incentivizing development in downtown cores and creating communities with housing and jobs near amenities that are accessible by multiple modes of transportation options.

So MPOs develop these strategies as part of their regional transportation planning effort and integrate land use and transportation planning to achieve regional greenhouse gas emission reduction target set by CARB. These targets, if achieved through the plan, would result in reducing VMT. But a more recent report evaluating the progress in meeting the SB 357 goal shows that the state is actually not on track to achieve these targets. Reducing VMT to achieve the 2030 greenhouse gas emission target and to meet SB 375 goals would require new state and local VMT reduction actions.

So to achieve California's 2030 greenhouse gas reduction goal, we need to reduce vehicle miles traveled by approximately 25 percent from 2005 levels. SB 375 will get us part of the way. However, both the Scoping Plan and target set under SB 375 do not address the state's more recent goal for carbon neutrality by 2045.

So SB 375, just to recap, looks at the regional planning process. So if the regional plans the MPOs development are implemented, will they achieve the greenhouse gas emission reduction set by CARB?

This next effort -- sorry, I didn't move the slide -- but there's 18 MPOs in California. And they work on identifying land use and transportation strategies to reduce greenhouse gas emissions.

Okay, so kind of the second piece to this work is a report we put out just last November. And so since ten years have passed since SB 375 passed, which kind of directed the MPOs to look into this planning exercise with sustainable community strategies, and this led to new conversations across the state about how regional plans can provide important economic, health, equity and environmental benefits for Californians. But have these planning efforts been enough? And what progress has actually been made through the implementation of the plans?

So last year, we published the 2018 Progress Reports, California Sustainable Communities and Climate Protection Act. And there was a report to the legislature on the implementation MPOs have done for their sustainable community strategies. What this report looked at was what progress has been made in implementing the strategies? What challenges exist for implementation? And what are some examples of regional implementation?

Our report, to kind of look into the

implementation question, we analyzed dozens of metrics. And what did the data say?

So the critical datapoint here is VMT per capita and CO_2 per capita are on an increasing trend, especially when you're comparing them to the anticipated sustainable communities strategies performance identified through these regional planning efforts. This falls short from the trajectory we're expecting to see in those plans.

So to better understand the rise in VMT, we also looked at two dozen other indicators. This graph shows the percentage of people who drive alone to work for selected regions. And as you can see, three out of four people drive alone, and the trend is flat or rising in most regions. The Bay Area is unique with a shrinking share of commuters driving alone to work.

When we talk about what's going on in a given region, I just want to emphasize, we're talking about the aggregate results of hundreds of decisions that are made by dozens of agencies and private actors in a given region and not just MPOs.

Another metric we looked at was transit

ridership. So annual transit boarding trends by the four largest regions are shown in this graph. While spending on active transportation has grown around transit service per person, on the left, has only barely recovered post-recession, and as of 2014, transit ridership, shown in the right, is falling. So is carpooling to work. Around 75 percent of commuters drive alone, an amount that's staying the same or growing in most regions.

Another metric we looked at, a very important one, housing. So this chart focuses on the Bay Area but is fairly similar to most regions, most of the other large regions in the state. In general, the housing cost burden has gone up with noticeable leaps in some income groups. Home construction is greatly behind what is needed, especially for low-income homes. This is causing costs to soar and may be lengthening commutes if people have to drive further to find a home that they can afford.

So why is this happening and what can we do? What do we need to do to get on track to where we need to be? So what were the opportunity areas?

Stronger policy interventions will be needed if we are to succeed in reducing VMT in a significant way. To achieve VMT reductions we need a holistic approach that includes better land use planning, increased investments in alternative transportation modes, creative partnerships between public agencies and new mobility providers, and pricing strategies. Incentives and pricing policies that encourage pooling and the use of zero-emission vehicles are also providing a source of revenue that may be reinvested into transit and other clean mobility options, particularly for low-income and disadvantaged communities.

We'll also need to put in place policies that address the demands of the future transportation system through new technologies facilitated by the mobile revolution, car sharing, bike sharing, ride hailing services.

And, of course, focusing on transportation systems will not be enough. We need policies that influence land use, as well, so minimum densities for new development to increase density and reduce the rate of sprawl and VMT, parking maximums with new development to discourage personal car ownership, and reduced costs of building new housing, and incentives and requirements to change or implement local land use regulations to support implementation of the regions sustainable communities strategies.

So these are kind of the central findings of that report that we looked back on implementation of SB 375.

So the following slides are examples of follow up to that vision.

So CARB executed a research contract with UC Berkeley to explore the technical feasibility of developing a statewide policy for zero-carbon buildings. This research will build upon the zero-carbon building research underway, and then also evaluate how GHG emission reduction strategies can be implemented at a community scale by municipalities. And the objective of the research is to leverage Low-Income Zero-Net Energy Housing Program in Richmond to create a benchmarking and GHG emission reduction framework for zero-net carbon communities. So this project is still underway but could provide some promising information about how to reduce greenhouse gas emissions at the community scale.

And kind of tying back to what Elliot was working on -- or talking about, too, CARB is working on SB 1014, the Clean Mile Standard, and it's an incentive program that was passed last year. The legislation directs CARB and the California Public Utilities Commission to develop and implement new requirements for transportation network companies for innovative ways to curb greenhouse gas emissions as new mobility options grow at a rapid pace. So this is -- this regulation development is currently underway and we're really in the early stages of this.

And so as I noted before, individual agencies have important work that they've done and can do, but real success will require collaboration amongst many agencies at different scales, local governments, and with community partners.

And that concludes my presentation. Thank you very much for your time.

VICE CHAIR SCOTT: This is great. Thank you very much. I don't have any specific questions.

Do you?

COMMISSIONER MCALLISTER: I just have

one. So I'm wondering, are we plugged into the zero-net carbon --
MS. MILLER: Yes.
COMMISSIONER MCALLISTER: -- feasibility study?
MS. MILLER: Yes. CEC's --
COMMISSIONER MCALLISTER: I'm assuming we would be but --
MS. MILLER: -- staff is represented on that.
COMMISSIONER MCALLISTER: Okay. Great.
MS. MILLER: Yeah.
COMMISSIONER MCALLISTER: Yeah. That sounds like a really exciting project, so I'm glad you guys are doing that. And you're probably aware of all the -- you know, or at least that there are complexities in the Building Code with how to deal with carbon versus energy. And so, you know, as we shift metrics the metric by which we determine cost effectiveness for the code update, figuring out how to sort of walk right tightrope is going to be interesting so that we can keep focusing on carbon but also, you know, comply with statute.
So anyway, glad we're working together on

that, so thanks.

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

MS. MILLER: Yes. My pleasure.

VICE CHAIR SCOTT: Appreciate it.

MS. MILLER: Thank you.

VICE CHAIR SCOTT: Okay. We will now turn to the forecasting community choice aggregation, and that's going to be Cary.

MR. GARCIA: I'm excited to use the term, we're switching gears, in this case. I was also at the -- yeah, thank you. I was hoping for that. I was also at the DMV this morning but it went very well. They had music playing and everything. It was awesome.

So I'm Cary Garcia. I'm the Lead Forecaster for the Demand Forecast and the self-proclaimed chief aggregator, is how I like to call it. Pulling together all the pieces for the forecast seems to be the bulk of my role these days.

But I'm here, really, to set the stage for and provide some context for the panel discussion we'll have later when we have some representatives from the CCAs and the state that

Lynn Marshall will help moderate today. And so I just wanted to set a little bit of background, first just giving a quick overview of our demand forecast.

The big distinctions here are really between the odd years and the even year IEPRs. And those -- in the odd IEPRs, we'll do a big data collection process we typically refer to as our forms and instructions process. And so that's the data collection that we do to inform our IEPR forecasts. And then running our full sector models, as well as transportation and self-generation models. And then all the various inputs, rates, and econ and demo and such.

But for the even year IEPRs, we don't have that formal data collection process. But what we do is we just update our forecast output from the previous forecast using new econ, demo and econometric models to make the adjustments to reflect the changing economy. But we also will do full updates for the self-generation, so as well as transportation forecasts which will primarily focus on light-duty electric vehicles, as well as medium- and heavy-duty and other electrified transportation.

But for each of these demand forecast cycles, we produce our demand forecast forms. And these are composed of our baseline forms that are organized by planning area that you may have seen on our website. At the end of the presentation, I put some links there. It's always kind of hard for some folks to find that information, so hopefully that's helpful.

And this is broken up by the three demand cases for those baseline forms. I guess you can't really -- oh, yeah, you can see that there. Perfect.

So these are baseline forms here. And then typically we'll have our hourly forecasts which will include the monthly peaks for the RA purposes. And then we have load modifiers that breaks out some of our demand forecasts.

And then, lastly, we have our load serving entity and balancing authority forecasts, or you've heard of them as our LSE and BA tables. And those will both be a baseline set of forms. And then the managed forms that have the various flavors of AAEE, and in previous history the AAPV.

And so focusing on that last form, the

LSE and BA table, one of the forms that we have there is what we call our Form 11C, which is our sales by LSE, or have it listed here as electricity deliveries to end users by agency. That's a long-hand term for that. And so this is going to be important for CCAs because if you look closely at it here, hopefully -- it's probably not big enough to see here but maybe on your slides that you have printed out, you can see that there's a breakout by the LSEs within each of the planning areas.

So in this case, I pulled PG&E as an example, and you can see how we categorized the bundle direct access. For PG&E, we have BART, separated it out. And then from then on you can see the breakout of CCAs going from Clean Power San Francisco down to Valley Clean Energy Alliance. And then further below you also see the breakout by the individual LSEs mostly being POUs. And then DWR and WAPA at the bottom, primarily water pumping.

And so this form is generated using historical date from QFER for our starting points. And then it's essentially a disaggregation of the larger planning area forecast. Those growth rates are -- essentially, the growth rate for the planning area is applied to the respective LSEs there. And then, if needed, we also make some adjustments for specific LSEs if there's a need for incremental load growth adjustments there.

And so as I mentioned before, this is sort of a breakout, a further breakout of the use cases for CCAs and how we use them in our forecasts, and who uses them is probably a better term there. So as I mentioned, the Form 11C, that's going to be sales by LSE going out for the full ten years. The main use case there is the CPUC -- or the main use case now is really the CPUC's Integrated Resource Plan. And as I said, that's essentially just a disaggregation, as you can see there in the method column.

The TAC area monthly peaks that I also mentioned before, that going to be used for the RA process. That's essentially taking LSE year-ahead projections and doing -- aggregating that up, making sure it lines up with our CEC IEPR forecast, and then apply an adjustment to make sure that's consistent for the RA, consistent with the IEPR forecast.

And that last piece there is you'll see the TBD there. That's really getting into forecasting CCAs that have yet to form. When I sort of spoke about in the Form 11C, that was mainly focused on CCAs that exist. And this next slide sort of breaks out that methodology in another way.

So the current method that I described there also applies -- which is used for all the LSEs but in this case also applies to the existing CCAs, is using those year-ahead filings. So in the RA process there's the peak demand that gets filed, as well as the energy proportion. And in previous history, we've used that energy portion, as well as looking at implementation plans that get submitted to the CPUC. And that's going to be used for the near term, the one- to two-year-out portion of the forecast in that 11C form that I showed earlier.

And as get into the mid to long term, what we're doing there, as I mentioned before, is really that disaggregation. And we have limited data specific to LSEs in that case. But a proposed improvement here is still keeping that one- to two-year-term process using those year-ahead filings and any implementation plans that we have to make any adjustments.

But then instead of just simply using disaggregation of the planning area forecast, we have developed forecasting zone projections. So our forecast is already disaggregated to a pretty good level of detail. And it's -- somebody had mentioned earlier, I came in a little bit later because I had that DMV appointment, but I saw they were talking about the LCR areas. And so our forecasting zones are pretty closely aligned to there but not exact. And I know some of the LCRs get kind of -- they're not set-in-stone boundaries. I think they do shift around a little bit. Somebody could correct me if I'm wrong.

But the idea there is that we can leverage those forecasting zone projections to get a little bit more of that regionality instead of, obviously, it's a pretty broad brush to say all these CCAs or LSEs are going to grow at the same rate as a planning area as a whole. So that could be beneficial.

And then further, to provide some detail into any load growth that is occurring to a specific CCA or an ESP, for example, it would be helpful to have some additional data to justify and to understand what the growth is occurring, or perhaps even as we move farther along into the development of CCAs, what happens with like opt-out rates, for example? So, you know, what is the movement back and forth, this load migration, either to a CCA or away from or however that may play out?

And so some of the next steps that I outlined here, and I mentioned this before, the need for the CPUC's IRP process, is really we need to sit down, perhaps through our joint agencies, to discuss the alignment of our processes. I think things are changing a little bit. You know, we transitioned from the LTPP to the IRP. And so I think there are some opportunities to make sure we're aligned there, to make sure that our forecasts are getting used in a timely manner and there's no discrepancies when we're making some of these planning and policy decisions.

Also, as I mentioned, we need to go through a process to identify some of the additional data requirements we may have through this data request process that we go through. And there's also another bit there, that there is a gap between our full IEPR demand forecast, as well as our -- gap between the full IEPR forecast and the update because there is no formal data request that's occurring there.

So we have to think about, perhaps, another process to collect some data, particularly when you have the case of CCAs, there may be some more dynamics there. It's a more dynamic, I guess, field or category of LSE. So we want to make sure, I think, we have the best information we have without putting a burden on LSEs or CCAs by asking them to continually submit data on a regular basis. So we'll have to think about that a little more.

And then the last bit I somewhat glossed over but I think it's important is really looking into the problemistic or even scenario-based forecasts of departing load. And think this is something that gets into -- when we get into the weeds in this about understanding, you know, what may be the best approach for the short term and what may be the best approach of the long term, and really understanding from our stakeholders not only the utilities, LSEs, CCAs, but also our joint agencies, the CPUC, the ISO, about understanding, you know, what would be the use cases for doing this within our IEPR forecasts. And so we really want to understand that a little bit better and get on the same page there.

But, really, I guess, hopefully this provides good intro to the panel discussion. I think, at least for me, I really kind of want to understand a little bit about the programs around CCAs. You know, what sets them apart from the typical utility out there? Obviously, the landscape is changing. It could be the case, you know, at some point where we're no longer actually focusing on the planning area. We could still do our planning area forecast but we're actually requesting a lot more information from these CCAs than we have in the past, and I think that will have to happen, as we see here, but I will leave it at that.

It kind of feels like an awkward transition but I guess we'll get the panel kicked off. Hopefully I sparked some ideas or thoughts with our panelists, but I think we have a whole host of questions as well.

VICE CHAIR SCOTT: Thank you.

MR. GARCIA: Yeah.

VICE CHAIR SCOTT: Thank you very much --

MR. GARCIA: So maybe I'll invite --

VICE CHAIR SCOTT: -- for the overview.

MR. GARCIA: -- them up.

VICE CHAIR SCOTT: Yeah. Why don't we have the panel come on up. And welcome. You have to push your mike button. There you go.

MS. MARSHALL: -- three CCAs of the 19 that are currently serving load. And really appreciate their time in getting here today. I know this is a busy time of year procuring for the year ahead, so welcome.

So we have Gary Lawson, who, actually, is an employee of SMUD. But he is managing wholesale services for Valley Clean Energy Authority. And then Rebecca Simonson, who is, I hope I say this right, Manager of Power Resources -- Power Resources Manager for Sonoma County -- I'm saying this wrong. And J.P., who just got here from the airport, and he is Lead of Local Development for East Bay Community Energy. And they can tell you more about their CCAs as we go forward with our discussion.

So Cary gave a good background. You know, in particularly, we've seen, in the CPUC Integrated Resource Planning, them now directing CCAs to use our sales forecast for CCAs in their integrated resource plan. This is a new use; right? We've been doing that table for use but this is a new application. So we realize now, we need to get more input from them on programs that we haven't been paying attention to include those in our forecast.

So to start off, we'd first like to hear about what source of decarbonization programs you're pursuing and, in particular, how those programs are funded? We have tended to pay attention to PUC, publicly-charge funded, and we look at certainty of funding as a measure of commitment of those programs? And then how are you measuring and verifying program impacts? And are there other decarbonization strategies you're pursuing that may affect electricity demand?

And who would like to start, this end or that?

MR. GARCIA: I also wanted to make sure that we were offering them an opportunity to just give a brief introduction.

MS. MARSHALL: Okay.

MR. GARCIA: If --

MS. MARSHALL: And I think you could do that as part of this first --

MR. GARCIA: Oh. Okay.

MS. MARSHALL: -- as part of this first question.

MR. GARCIA: Okay.

MS. MARSHALL: Feel free to give any kind of background for your agency.

Gary, you want to start?

MR. LAWSON: Yeah. My answer is pretty easy. Valley Clean Energy is a fairly small CCA. It's encompassed in the County of Yolo and it's the Cities of Davis, Woodland, and unincorporated portions of Yolo County. So they're fairly small, I wouldn't say super sophisticated at this point. They're kind of growing into the role. So they don't currently have planned any programs specifically for decarbonization, apart from their current efforts to procure renewables in seeking to meet the RPS requirements, as well as exceed those.

Just by way of introduction, in terms of load forecasting effort, Valley Clean Energy launched last June. We did the first forecast for them in late 2017 after the 2017 IEPR process. So the 2019 IEPR process was really our first opportunity to provide a little more robust planning forecast to the Commission.

I will say that we're taking steps to incorporate more decarbonization activities, whether specifically programmatic of not. In this year's IEPR, we did make an explicit adjustment to the forecast to try and account for net-metered solar adoptions, which is fairly high penetration in Yolo County, as well as we made a simplified explicit forecast adjustment to recognize electric vehicle adoption and charging loads associated with that. So while not super sophisticated, I would say that we're making steps to increase how we forecast the effects of decarbonization activities and load changes.

MS. MARSHALL: Okay. Rebecca?

MS. SIMONSON: Good afternoon. As Lynn said, I'm Rebecca Simonson. I'm the Power Resources Manager at Sonoma Clean Power. Sonoma Clean Power has been in existence since May of 2014. We launched in Sonoma County. And in June of 2017, we expanded to Mendocino County. We currently serve around 230,000 customers.

By way of introduction, I just wanted to explain my role at Sonoma Clean Power. So I'm responsible for managing our short-term day-ahead forecasts, as well as near-term, our monthly and year-ahead in terms of revenue, budget, rate settings, our GHG and RPS goals, our resource adequacy forecasting, as well as the ARRA process with PG&E for them forecasting their departed load. And we have participated in the IEPR process in 2017 and again in 2019.

And I work very closely with our customer service team, so I am able to assess any trends that are happening in the residential sector from a customer point of view, and also from our large commercial customers. If there is some demand-side resource they intend on designing and installing, I get a good heads-up on that.

I also work very closely with our programs team. All of our forecasting incorporates all aspects of programs. In fact, anytime we are considering a program, the procurement team is included on that.

So in terms of decarbonization, Sonoma Clean Power has had two rounds of what's called the Drive EV Program. We've incentivized the electric vehicles and given away free electric vehicle charging stations and encouraged customers, as part of that, to sign up for our demand response program which is called Grid Savvy. Currently, Grid Savvy only includes electric vehicle charging. However, we intend to roll out smart thermostats, heat pump hot water heaters, heat pump heating and cooling, and behind-the-meter storage.

And as those programs roll out we, generally, we implement them through our own budgeting and some through actually CEC grants. So we are not tied by the TRC cost effectiveness, so we are able to treat those as pilots, and to assess potential impacts on load and cost to our customers and cost to Sonoma Clean Power and whether that is, basically, a fast fail or whether it's scalable and we should implement it for the rest of our territory.

I think that's probably good for now.

MS. MARSHALL: J.P.?

MR. ROSS: Yeah. Good afternoon. J.P. Ross, Director of Local Development, Electrification and Innovation with East Bay

Clean Energy, and it's actually East Bay Community Energy. So we serve about 600,000 meters in Alameda County, all of Alameda County, except for the City of Alameda which has their own POU, as well as the two Cities of Pleasanton and Newark are not part of our service territory.

We are progressing with some additional cities. So the City of Tracy as voted unanimously to join our CCA. First vote was last year. We've got a couple more readings of that, then Tracy -- so that Tracy. And then Pleasanton is also looking at entering. So that will increase our load. Those are forecasted for the 2021 enrollment year.

We're about a six terawatt business as of now. And hopefully, if we do our job right, we'll be closer to 15 in a few year, maybe a decade. We want to do that through electrification of vehicles and buildings. So right now there's about six terawatt hours of gasoline and diesel that's burned or purchased in Alameda County, and another six terawatt hours of natural gas that's burned in buildings. With heat pump efficiency, that probably doesn't actually equate to 6 terawatt hours of electricity, so that’s why I bring it down to about 15. But that’s what we want to do with our programs in the big picture.

So we have a $6 million budget that we’ve allocated this year for local development and local programs. Each year, we also put one percent of our operating revenues into what’s called the Local Development Reserve fund. So that’s kind of a revolving loan fund that we are still defining the boundaries of how we make those investments. But over time that will become a pretty substantial resource that we’ll be able to continue to invest in our local development activities.

To do a quick run-through of some of the programs, we started serving customers, commercial customers, in June of 2018, enrolled residential customers in November of 2018. So we’re still quite young, one of the younger CCAs. I came onboard in January, so still less than a year in.

So far what we have done is we’ve launched two demand response programs. So we run a Peak Day Pricing Program, which is analogous to PG&E’s Peak Day Pricing Program for large commercial customers. And then earlier in the summer, we also launched a Battery Demand Response Program. So we have about 500 kilowatts of batteries aggregated between commercial and residential customers. And we are calling events based on wholesale pricing to mitigate our wholesale procurement activities. We called one earlier this week. So we're trying to see what those assets do as we try to manage them and aggregate them up. So we have those two demand response programs.

We've also just recently, last week, issued a solicitation for electric vehicle support. So many of our cities have electrification, fleet electrification strategies, but didn't have the technical resource to help their fleet managers and cities plan through that. So we're allocating between -- up to, probably, $400,000 to help our cities with the technical resource to actually achieve those fleet electrification plans.

We also just submitted an LOI for the 2020-21 EVIP cycle just this week, looking to work with the CEC on your Electric Vehicle Incentive Program.

We have signed contracts for over 500 megawatts of new solar and wind; 60 megawatts of that will be in Alameda County. We have LOIs that will be used for another 100 megawatts of Alameda County wind. And over 80 megawatts of batteries, so that's six times our required battery amount. We're a 1200 megawatt peaking LSE, so our requirement is, I think, 12 megawatts, so we're substantially above that with existing PPAs that have been signed for batteries.

We are also running a resilience program for critical facilities in Alameda County, so this is a joint activity. It's funded by a Bay Area Air Quality Management District grant with PCE from San Mateo County. So we have now created an inventory of over 100 -- or, sorry, 500 critical facilities that have been deemed critical by city governments of those two counties.

We are doing a technical assessment across all of those rooftops and the load profiles of those buildings to identify solar-plus-storage opportunities on those buildings for resilience. And a product of that will be a procurement, that we will go out on behalf and with our cities to procurement solar plus storage to make those critical facilities more resilient in times of earthquake or fire or PSPS (phonetic).

So that's ongoing and should complete the analysis and identification of those opportunities by March so that next year we can go out with that volume procurement.

We also are pushing Reach Codes. So your team is probably aware of it, but there's lots of activity across the state with Reach Codes for building electrification in the 2020 -- or the 2019 Building Code cycle. So between six and eight of our cities are planning on pushing new Reach Codes for both building electrification and vehicle electrification. I'm quite excited about that. Obviously, Berkeley has been in the news with their natural gas ban that they have passed. They will also be passing a Reach Code to kind of create a foundation for that. And many of our cities are looking at either an all-electric code or the mixed fuel version which prioritizes electric buildings over mixed fuel buildings.

We issue a series of grants. We've done

that with some of our community stakeholders. We have issued about a quarter million dollars in grants to local CBOs that are trying either Level 1 vehicle electrification in multiunit dwellings, community solar applications, installing solar on nonprofits, a variety of things to kind of help curate and cultivate nonprofit activities that are kind of solving and addressing energy-related environmental issues in our jurisdiction.

We are a data-driven organization. So we have now acquired all of the DMV data for all light-duty vehicles registered in Alameda County. It's about 27,000 battery-electric and plugin hybrid vehicles in the county. We expect that to grow to about 86,000 with the 2025 goal of 1.5 million vehicles, and then 266,000 by 2030. So there's a huge growth in electric vehicles. We know where those vehicles are and we certainly want to roll that data into programs.

We've also acquired all the forklift data in California in our territory from CARB to run some forklift programs. About 60 percent of those propane -- sorry, 40 percent of propane, 40 percent of diesel, and only 20 percent are electric, so there's a large electrification opportunity with forklifts.

And there's a lot of heavy-duty vehicle transport in Alameda County, as well, certainly originating from the port. So how we can not only focus on light-duty vehicles, which the Electric Vehicle Incentive Program will focus on, but also medium and heavy duty with the number of DACs and air-quality impacted constituents we have in our territory.

So that's a brief overview of EBCE and the programs that are currently -- have currently launched and are planning on.

Oh, actually, sorry, one more thing. Sorry to monopolize.

We're also right now in the process of building a solicitation that's, I think, quite exciting to go to the market to work with residential and commercial focused storage and solar-plus-storage providers to purchase RA, resource adequacy, from local installed solar and batteries or batteries alone in Alameda County. So our goal is to get at least 10 megawatts of RA by the 2022 filing, so interconnected by September of '21 is the plan and do that in partnership with local providers who would use local labor to install that and provide much more resilience to our residential and commercial customers.

So we're building that solicitation now and that will be going out at the end of this month so that we can have at least a little more of an accelerated push on more batteries before the 2021 fire season.

MS. MARSHALL: Okay. Do you have questions at this point?

COMMISSIONER MCALLISTER: Is there a little room for questions? Yeah, I have a couple questions.

MS. MARSHALL: Sure. Go right ahead.

COMMISSIONER MCALLISTER: So that was great. Thanks a lot. I was going to ask about RA and I guess I'll just kick off where you started.

And, you know, that's great. I guess I wanted to kind of get viewpoints from the other two, as well, about kind of the challenges in the RA market right now and how that -- what that looks like in terms of, you know, it's a little bit of a crowded field and, you know, prices are volatile, so that's a great solution.

I guess I'm wondering what the thinking of the other two in maybe a little more broader context about the RA market generally.

MS. SIMONSON: Yeah. So as part of our Grid Savvy Program, our long-term goal is to aggregate all the different technologies, the behind-the-meter solar, the heat pump hot water heaters, heat pumps, smart meter -- or smart thermostats, and electric vehicle changing stations, and aggregate those to participate in the proxy demand response as part of RA and other grid services.

We don't currently have a megawatt goal. But as you mentioned, the RA market is getting very crowded and is also becoming much more specific in the local areas. So it is our intent to procure utility-scale storage as well.

MR. LAWSON: WE don't have any specific goals for local RA in storage. But I will say we are evaluating it, certainly the price increases in the RA market because of the additional friction of having to go now procure from six local zones, where previously we had one aggregated zone, as done a lot to push pricing up. So it will make batteries much more cost effective in relationship to that.

COMMISSIONER MCALLISTER: So, yeah, I live in Davis. So, you know, I've got a 240-volt circuit in my garage. So if you want me to hang a battery on there, you know, make it worth my while, okay?

So, let's see, I guess on demand response, I have kind of -- it's a little in the weeds but I think it's important.

How are you managing -- I guess this is more for J.P. -- but how are you managing -- well, and for Sonoma, to the extent that you've got the DA program -- how are you managing just in a -- as a pragmatic, programmatic issue, the visibility, the dispatch, the settlement, all that, the aggregation? Are you working through third-parties, or are you doing that yourself, or what's your kind of market approach there?

MR. ROSS: Yeah. If I could, I'll answer your -- maybe a little bit more on RA, and then go to demand response.

So we, you know, we have over -- it's just under a gig of our system RA requirements --

COMMISSIONER MCALLISTER: Um-hmm.

MR. ROSS: -- and over 300 megawatts of

local that fall to us, so that market is increasingly illiquid. And, certainly, we're looking at Diablo coming offline in 2024-25 and what's the going to do. That's going to be quite interesting. So we're definitely on the market and thinking, you know, I think creatively with the CEC on how the CEC is doing forecasting and looking at how we are, you know, looking at forecasting at the CEC, as well as how the PDR, Proxy Demand Response Program, through the CAISO is operated. There's some limitations on how we are able to value batteries, behind-the-meter batteries, in those programs, and it's actually quite limiting.

So as you are probably aware, you know, one limiting factor is in the PDR a behind-the-meter asset can only be discharged up to the level that the building is consuming power. So if you can't export, then you're curtailing your ability to provide capacity and energy into the market by, some would say, 50 percent. So why are we limiting batteries when we need more RA and we need more capacity?

So similarly, if an event is called during a period of time where a battery is normally charging and that battery doesn't charge, then that gap, that delta is not counted toward PDR. So we are handicapping these assets that we are trying to get into the marketplace through the way that program is operating it.

You know, I think similarly, we can talk about how the CEC forecast is built and how we might really be valuing these assets that we're putting online that are much more flexible than larger assets which have longer timelines.

COMMISSIONER MCALLISTER: Well, I guess just to put a finer point on this, I mean, they can be more flexible if the systems are in place to make them flexible and to call them and to aggregate them --

MR. ROSS: That's correct.

COMMISSIONER MCALLISTER: -- and have visibility in that.

And so, I mean, I guess this is what I'm asking, really, like what -- you know, we have some authority in this area, that may be codes, it may be load management standards. And so, you know, what are the kinds of things we could be thinking about to kind of standardize --

MR. ROSS: So, yeah --

COMMISSIONER MCALLISTER: -- some of this?

MR. ROSS: -- agreed. So to answer, you know, on the DR Program, I'll be quite blunt, I put that program in place in about a month. And so we're using, I think, Mailchimp (phonetic) and Easy-SMS (phonetic) to call events is how we are currently calling events. But we're actually learning a lot about how those batteries are operating and how we would call events. It's only 500 kilowatts. We are really only using those resources to manage our wholesale procurement costs. But we learn a lot about that.

You know, so for example, one of the learnings out of the first event I called was I pushed our battery providers to respond within an hour, a one-hour period of making a call which, considering all the manual processes, is actually quite quick. Of course, if you automate then you can have it faster.

But the first event that we called was when we had day-ahead pricing and we saw the market clearing price above $150 to $200 between 6:00 and 8:00 p.m. And so I looked at that and I said, well, I could call that event at 5:00 which gives me my one-hour period, but if I call that event at 5:00 then the battery has already been discharging for an hour, so I've already lost some of the powder in my keg, so why would I do that? So I call it at 2:00.

So speed of response when the battery is generally discharging from 4:00 to 9:00, probably, linearly to manage your battery resources, speed doesn't -- necessarily isn't it your friend. If you're respond to AS or frequency response or other, or you're settling in five minutes, you know, your market integrated, certainly, speed has a lot more value. But, you know, as we're looking at these batteries and how they respond and how we would call events, that's the reason I said, well, I just started, but let's get a program up and running because I'll learn a lot by thinking of these things that I wouldn't think of if I was like, oh, I'll do a battery demand response program next year.

So over time, as we put more resources in, electric vehicles, thermostats, heat pump hot water heaters, space heaters, all those devices, then we would certainly bring in a third-party. That’s not our area of expertise. But for right now, spreadsheets and everyday thinking about it, from my perspective, is the best way that I can kind of learn how these batteries can add value and how we would actually dispatch them.

COMMISSIONER MCALLISTER: Thanks.

MS. SIMONSON: And we do use a third-party aggregator but we can call the event. And right now we’re calling events, basically, in the pilot stage at points where we see wholesale prices driving the event, but also just as a learning exercise until we can scale up and make them a good resource for Sonoma Clean Power. Right now it’s just through a third-party aggregator but we get to call the event. And we’re using it as a learning study.

COMMISSIONER MCALLISTER: Great. Thanks.

MS. MARSHALL: So related to that, can you speak to, a little bit, about how you’re evaluating the program performance, and then, you know, how this presents challenges for then forecasting, so based on demand forecasting?

MR. ROSS: Sure. So for right now, we’ve established our own baselining criteria. So we, at the end of every month, we will get from the participants the monthly discharge and charge profiles of those assets. And then we will compare event days to non, to similar non-event days, 10-10 kind of thing. And so we haven't done that yet. We will learn a lot from our first exercise on how that baselining methodology would work. But that's how we're evaluating success.

I think, you know, the other thing that we are trying to get our hands around is what is the economic value of this to us and our customers? So in very rough numbers the way I price this program is we call events when we expect the price to be above $150 a megawatt hour and we pay $100 a megawatt hour with an average estimate that it costs us 50 bucks during those times period. But that's not actually what it costs us to serve electricity to that customer during a period where they're either charging or not charging or discharging that battery.

So we are also going through the exercise of what's the marginal cost? And as those batteries shift from where they're charging and discharging and what that means to the customer's load, what does that mean for our actual margin which is it's the margin that goes back from the program back to our customers in the form of other programs and savings?

So it looks easy on the surface but it will be good, complex calculation as we run through it and have this summer's learnings.

COMMISSIONER MCALLISTER: Are you worried about sort of over cycling batteries? I mean, you know, they do have a limited cycle life. You know, I hear all sorts of different numbers. I know a little bit about batteries. You know, it's like -- and I know that ISO is thinking about, okay, well, how much should we be diversifying our storage population?

MR. ROSS: Yeah.

COMMISSIONER MCALLISTER: So if you work them too hard do you think that's going to impact the customer in a negative way?

MR. ROSS: So to -- as far as the overall customer relationship, we don't actually get in between there. So we are working with aggregators who are running those batteries. And those aggregators have a warranty obligation that they know better than we do, as well as a customer agreement that they know better than we do. So if their agreement with the customer is they're always going to leave 20 percent in the battery for a blackout, we're not going to get in the way of that. We're just saying discharge everything you can in this period.

Also, these batteries are set to discharge every single day. So we're just probably shifting the timeframe and maybe accelerating the discharge going, in my previous example, instead of a four-hour window or five-hour window from 4:00 to 9:00, we're asking it to all go from 6:00 to 8:00. And so there's a doubling of the capacity rate but it's still a single discharge during the day, and then it's being charged up at night.

We are not managing those assets. We are not on the hook for the warranty. And we're expecting that if that gets over-discharged then -- you know, we're effectively not operating as the SC in this event.

I think for utility-scale batteries, you know, that can be a bigger issue where who is the SC is actually quite important. And I think what we've found so far is that when the battery operator is the SC, then maybe they have some problematic pricing about how they're actually dispatching that battery into the market.

So in all of our utility-scale contracts for batteries we are the SCC because we know that those batteries not only have to be sitting there, they actually have to be discharging into the grid when we need them.

MS. MARSHALL: Okay. So that was actually the second topic, demand-side grid resources.

So let's move on to, more generally, to demand forecasting. And can you talk a bit about how you do your forecasts, specifically demand-side resources, combined effects of electric vehicles, and now adding storage, et cetera?

So who would like to start?

MR. LAWSON: I can start. I kind of referenced in my opening remarks, effectively, we're adding in specific modifiers to the load forecast to reflect the conversion of the adoption of net-meter solar by customers. Again, the solar penetration is fairly high in Yolo County, so we wanted to reflect that going forward, so we did include the explicitly. It's not programmatic. It's just self-adoption by customers.

And in addition to that, we also put in a factor for EV charging loads over time, just to capture the expected growth of EVs, again, nothing specifically programmatic at this point.

MS. SIMONSON: So we start with our hourly CAISO settlement historical data. We forecast -- we update our forecast, pretty much monthly. We forecast by load profile so we have -- we forecast by residential and small commercial, medium commercial, large commercial, industrial, ag, street lighting, traffic control. And, obviously, they all have different variables behind what you need to consider in their forecasting. We also break down our NEM customers, the growth, and what we believe to be the capacity behind the meter. We are closely following our EV trends and monitoring those as the months go by.

And so as we start with this hourly forecast, we then build up to the yearly forecast, and that's done on an hourly basis. And from there, this is what we call our base forecast, so we forecast down to every hour to ensure that we are forecasting our peak accurately. And from there, in the long-term forecast, we determine trends and behind-the-meter solar, behind-the-meter storage, electric vehicles, energy efficiency, building electrification, and we profile that across the years and model those discretely and so that we can look at the effects of each of those and rachet those up and down depending on what our goals are or what the trends we see going forward.

I think the most important thing about the way we forecast is we do it in-house and we have a very clear understanding of our customers. And we are able to see trends relatively quickly that may not be readily apparent. And we are able to respond to those accordingly.

You know, I kind of want to talk specifically about what we found last year. In the EV rates, we were seeing customers that were 7 to 300 times -- using 7 to 300 times the amount of a typical residential customer, more than a home that would have two electric vehicles, more than a home that would have pools and air conditioning. And we noticed a drastic steady decline and were able to go in depth and look at what might be going on.

And we determined that the legalization of cannabis in our county was driving wholesale prices of cannabis down such that home growers were no longer economically viable and that load was departing and was not going anywhere. And we were able to respond to that from a budgeting and revenue perspective. That's something that we would never have been able to parse out or distinguish had we been using a consultant or we weren't that familiar with our customers.

So I think that's just a really interesting thing that, you know, because we have your customers and we are very familiar with our territory and our customers, we are able to really get down into the detail of what's going on with our load.

MR. ROSS: So, let's see, on the forecasts, we've -- so one of the first things that we did was invested in a data scientist team. They have spent the last year-and-a-half building a data warehouse, so we get data from PG&E every day and we download that into our data warehouse, so we have four years now historical that we use for all sorts of analytics.

We built our own forecasting engine. So I think at last count it was within three to five percent, plus or minus, on a day-ahead forecast compared to what we're seeing wholesale prices are. And that's how we -- we build that up into our annual forecast.

I'd say, you know, some of the things that we've done with that so far is we've been using that data warehouse to, and our team, to evaluate where we expect to see all-electric heating in our homes, where we expect to see A/C units in our homes. And we are also looking at how our electric vehicle fleet is operating.

So as I said earlier, there's about 27,000 electric vehicles in Alameda County. We've looked at the customers that are EV rates. About 30 percent of those customers are on EV rates. And then we did a disaggregation of those to understand which of those are on Level 2 and Level 1. It looks like about 20 percent of those are on Level 1. We don't have that data. But we have actually just requested similar data from PG&E to try to get everything that they have on solar and storage. And I'll ask for EV interconnection, as well, because they have a lot of that information, so we can pull that in and start to put it into our models so that we can be more effective.

You know, there's -- we have about 30,000 NEM customers, so 27,000 electric vehicles, 30,000 NEM customers. I don't think that that's a coincidence. There's a lot of overlap between those two areas.

And some of the things that we're doing on the programmatic side is now looking at where that PV is located. So as I said, we've requested from PG&E. We know who's a NEM customer but we don't know the size of that system. We don't know the modules or the invertors on that system. So we want to look at, you know, where are those systems located? What's their performance? We don't have the performance of the systems. Obviously, we just have the net meter output.

I just came from a solar conference this morning in Salt Lake City and had a conversation with one of the companies that we incubated out of our offices while I was at Sungevity. And they have now 300,000 systems operating in their platform, PPA systems, large utility and commercial and residential systems.

So how can we work with a company like that who can -- who already has a lot of the third-party-owned systems in their database from a monitoring perspective? And then use that data to create a proxy performance out of the systems that they don't have in their system. So if they have 30 to 50 percent of the systems in Alameda County, in our territory, in their system, they can actually create a proxy performance out of the rest of the systems once we tell them that this location, it's at this tilt and orientation with these modules and this invertor, which we will all get from the PG&E data that we've just requested. So you know, we're really trying to match that up.

We're also doing an analysis right now in partnership with Google to identify the solar resource across every building in our terr. And that's a piece of data that will probably go into our resiliency RFP that's going out, not the customer data but the capability and the resource that's out there because we want to make our solicitations really responsive -- you know, easy to respond to and easy for those providers to price so that we know that we're getting the best price back for the commodity that we're purchasing, which is RA. We want them to know that they can actually deliver on it.

COMMISSIONER MCALLISTER: I what to ask a question about the data exchange between the utilities and you guys.

So you know, one concern about kind of having another layer in there is just sort of friction that's created handing the baton up and down. And early on, certainly, there were issues getting data from the big utilities and, you know, disruption was having in real time; right? So, I guess, has that been worked out? I mean, when you give a data request to PG&E, is it happening in a way that is relatively efficient and effective or there's progress there, needed there, or what?

MS. SIMONSON: So for the data requests, we only needed to use that for our feasibility when we had no insight into our customers. Now that we get a daily, same with East Bay, as East Bay does, we get a daily transfer of hourly meter reads from PG&E directly over to our database, and that just happens automatically. It's a pretty streamlined process.

MR. ROSS: I think -- so I think I only just joined and I've done, I think, two data requests to PG&E. Both of them came through, I think, within a week. We got this last PV and battery data request through, so I haven't looked at it yet, so I can't tell you how clean it is. But -- so I'm happy with that, you know? And I can't really answer for the rest of the business, the rest of the organization. But, you know, I think it's gone smoother.

I think some of the things that we struggle with a little bit more are where there's systematic constraints from the PG&E system --

COMMISSIONER MCALLISTER: Yeah.

MR. ROSS: -- so the 4013 data that we get is, you know, kind of the qualitative data across the customer base, so CARE and FERA and medical baseline and, you know, all-electric, non-electric. So there's a limited number of fields there. And if we want to try to increase that, then that's, I think, where we come across some challenges. And we -- I think, you know, you're getting -- we try to be data heavy and make data-driven decisions. And so that's where I see us running across some more challenges --

COMMISSIONER MCALLISTER: Thank you.

MR. ROSS: -- at least at the programmatic level. I really don't, at the procurement level --

COMMISSIONER MCALLISTER: Yeah.

MR. ROSS: -- that's not my (indiscernible).

COMMISSIONER MCALLISTER: That's great to hear. I'm glad everybody's working together nicely.

MS. MARSHALL: Okay. So finally, so Staff is focused on how we can improve our CCA forecast and what additional information we should be getting.

What are the priorities that, from your perspective, that we should be focusing on? You know, a few challenges we're concerned about are this handling of the solar plus storage type of resource, forecasting, expansion of CCAs in the future. But what are your thoughts on what issues we ought to be paying attention to?

MS. SIMONSON: Certainly, expansion of CCAs and creation of CCAs will change the forecasts as they go.

As mentioned previously, we are able to adjust and refine and provide the most accurate forecasts we can on pretty much a monthly basis. So I think the best thing that can be done is to have a forecast that is able to be updated, at least, yearly, at least midway, even midway through the year.

Currently, the way we forecast, you know, we provide our initial -- for resource adequacy is we provide our initial year-ahead forecast in April. And the only modification we're allowed is a strict definition of load migration, which is a load moving from one LSE to another. So if that load was gone due to something, like cannabis departure or because of a mass wildfire or any sort of -- or mass adoption of behind-the-meter solar because -- plus storage because of public safety power shutoff fear or the Title 24 standards, we can't update that, and that presents a problem. That presents over-procurement that passes down as costs to our ratepayers.

And so I think that would be our number one request is that those forecasts are allowed to reflect the most accurate data that we have in a practical manner. I do understand that we can't update our forecasts, you know, every day or every month even, sometimes, but at least to be able to provide an accurate forecast, at least yearly, as close to a compliance deadline as possible and not be restricted by what's currently the limited definition of load migration.

MS. MARSHALL: Yeah. To be clear, that's a CPUC resource adequacy role, not a CEC role, so --

COMMISSIONER MCALLISTER: Yeah. I mean, I guess I --

MS. SIMONSON: Correct, but --

MS. MARSHALL: Yes.

MS. SIMONSON: -- the IEPR forecast --

MS. MARSHALL: Is --

MS. SIMONSON: -- is utilized.

MS. MARSHALL: -- the control total.

MS. SIMONSON: Um-hmm.

COMMISSIONER MCALLISTER: Yeah, I know. I mean, the -- let's keep in mind what the forecast is for; right? So it is a long-term view of things. And so the PUC has a task of translating that into a procurement regime; right? So you know, we don't want to jump tracks too much.

But I guess it does kind of bring up another issue, just of coordination between the IOU and the CCA in terms of, okay, how do we make sure that we're optimizing investment in the distribution grid? If you guys are out there doing DR and leveling load and doing all this stuff that optimizes the system as it exists, you know, we want to make sure that, you know, that the right hand over here is doing -- you know, is coordinating with the left hand and that investment decisions in infrastructure actually reflect that investment pattern or that forecasting need based on all the real wedges of resource.

So I guess, I mean, I kind of wish, you know, we had sort of a mixed panel here of like utilities and CCAs. But I just want to register that concern because like there are more kind of, you know, chefs in the kitchen here. And we just want to make sure everything comes out tasting right.

MS. SIMONSON: So we do work pretty well

with PG&E and the ARRA forecast procedure, so that's an annual procedure. We provide them an initial forecast in February, an updated one in September. And we do a meet and confer over 30 days where we talk about what there might be, differences between our forecast and theirs, and we come up with an agreed forecast, and that works really well. And I think that that process going forward to inform the baseline --

COMMISSIONER MCALLISTER: Yeah. Exactly.

MS. SIMONSON: -- IEPR forecast as it relates to PG&E and (indiscernible) load and the individual LSEs would work well.

COMMISSIONER MCALLISTER: It kind of goes to the methodological question we were talking about earlier. I guess Hongyan at Edison was talking about this, as well, like sort of a new methodological approach that involves the stakeholders in an appropriate way. So anyway --

MS. MARSHALL: Right. So I think you weren't here this morning. Edison, in the context of, you know, widescale electrification, is looking to the CEC to do more local forecasting to support distribution level planning, so a much finer level of disaggregation. And then, obviously, that has interactions with --

COMMISSIONER MCALLISTER: Yeah.

MS. MARSHALL: -- activities the CCAs are undertaking.

COMMISSIONER MCALLISTER: Yeah.

MR. ROSS: Yeah. I think I'll take kind of the programmatic view of the question and, certainly, longer term. You know, I'd say those distribution resources that we're talking about and distribution loads are the ones to take -- you know, pay attention to. So as we look at, say EVCE's expected EV growth by 2025, 86,000, that will add about 500 gigawatt hours of load if you look at it from a spherical cow perspective of all those are light-duty vehicles, that's what you get. Sorry.

COMMISSIONER MCALLISTER: You're going to have to tell the Court Reporter what that meant.

MR. ROSS: Sure. Think of a spherical cow as an old -- from Commissioner McAllister's and I graduated school program, think of everything as a spherical cow and you can back of the envelope the cow.

So if those are light-duty vehicles, then you're looking at 500 gigawatt hours, so it's almost ten percent load growth for us. In the next five years, we expect that to come online.

The interesting thing about that is, you know, continuing on that calculation, we're a 1200 megawatt peaking facility. If those are 60 kilowatt hour batteries, that 14,000 megawatts of load -- of capacity, sorry, of capacity driving it. It's over ten times our peak capacity in distribution batteries. So that's, you know, a huge resource. How are we going to use that? Can we use it wisely and start to get new EV drivers who are adopting these vehicles into the game, so what does that actually mean?

Right now, people come home with residential chargers. They hit a button or it's already set and their vehicle doesn't charge until midnight. So Sonoma Clean Power's Grid Savvy Program, it's hard to get DR when the charger says it's off until midnight. How do you actually mobilize that resource? And also, we don't have a lot of renewables coming on at midnight, last I checked. So how we, you know, create the incentives and rates so that people start to get in the mind of need to charge my vehicle during the day if I'm home during the day, fleet charging.

Certainly, the Electric Vehicle Incentive Program, that's good dollars for DC fast chargers and fleets so that we can get more daytime charging. A lot of the contracts we're signing for new solar and storage, you know, it's under 25 -- it's $25.00 to 30 bucks. It's the cheapest power you're going to get. So we need to find load that can utilize that resource.

Similarly, batteries, about six months ago when I was doing research for the Battery Demand Response Program, I think there was 3.6 megawatts of batteries that had been interconnected through the Self Gen Incentive Program. There's 14 meg that's in the queue. So within the next probably six months, just in our territory, we're going to more than quadruple the existing interconnect batteries. That's a huge resource. How do we mobilize that and have it play in the market? It's obviously what we're trying to do on the CCAs. So basically do it quickly and learn from it so that we can integrate it into that forecast.

COMMISSIONER MCALLISTER: Lynn, are you

going to ask about rates, rate design?

MS. MARSHALL: Well, that's a good question. And one of the things I've noticed is that the CCAs have somewhat different rate design, many of them, than the IOUs. There's, I believe, no tiered rates. Can you comment on how, you know, what -- how rate design might factor into, you know, say electrification strategies?

MR. ROSS: Yeah. So, well, I think most CCAs are mirroring the IOU rates with some kind of a discount. So most of us have three products, two or three products. We have three products, a Bright Choice product which a percent-and-a-half cheaper, an 84 percent carbon free, last year it was actually procured at 90 percent but 84 is what we are promising, and then we have a Brilliant 100 product which is the same price as the PG&E base rate but 100 percent carbon free, and then a Renewable 100 product which is a penny per kilowatt hour more and 100 percent PCC 1.

So a lot of us have those. They're named different but they basically mirror PG&E's rates. And when PG&E puts new rates on, like their subscription rate for EVs, I think most of us plan to mimic those.

So right now, you know, I think only one -- I think only Monterey Bay has the ability to run their own rates and disconnect those two things. All of us are looking at and building the capability. I think by the end of the Cal year we should have that capability. I'm not sure when we'll actually use it. But, you know, actually starting to run our billing determinants and run our own rates based off those building determinants is something that all the CCAs want in the long term. In the medium term, rates are the best mechanism we have.

So how do we utilize those rates to get the types of responses that we want from our customers, driving, you know, low midday rates for EV chargers? It seems kind of obvious. And that's how the rates are moving. CCAs, I think you'll see, are probably -- would take that and go very aggressively down that path because it aligns with our mission and how we want to see, you know, at least one of those resources grow quite quickly.

So you know, I think we're kind of --

we're still pretty new in that realm and everyone's saddling up to try to ride that.

COMMISSIONER MCALLISTER: Yeah. Okay. So I think this is a fundamental topic. And, I mean, it's not exactly -- forecasting tends to be sort of like, okay, let's try and anticipate what's coming down the pike; right? And so this is more of proactive policy discussion actually, I think, and I'm not exactly sure what this looks like. But I think the Energy Commission could play a pretty valuable convening role in terms of, you know, we don't do rate design, we certainly don't regulate the IOUs on rate design, that's all over that PUC, but I think there are some emerging practices, potential best practices for getting the kind of mobilization of demand resources that we're going to need, that we all, I think, agree in this room, that we're going to need and that are coming, kind of. You know, those resources are coming; right? So let's figure out how to incentives the right behaviors.

MR. ROSS: Absolutely.

COMMISSIONER MCALLISTER: So I guess I'm just putting that out there as maybe a recommendation for the broader IEPR, maybe not as part of the forecast, is that we convene a conversation like that, you know?

MR. ROSS: Yeah. Certainly, having -- I think what you'll see from CCAs is we just have to go to our board. So as far as speed and innovation goes, you know, that doesn't mean that we're going to throw a bunch of rates out because once you throw it out you've still got to manage it.

COMMISSIONER MCALLISTER: Absolutely. Yeah.

MR. ROSS: So that doesn't mean that you're flippant.

COMMISSIONER MCALLISTER: No, definitely. I don't mean to trivialize for sure.

MR. ROSS: I totally agree.

COMMISSIONER MCALLISTER: It's a big deal.

MR. ROSS: But, you know, you'll --

COMMISSIONER MCALLISTER: And there's equity issues. And, I mean, there's a lot going on there.

MR. ROSS: Yeah, there's a lot going on there. But I think you'll see that we have a faster timeline, is what we would say.

VICE CHAIR SCOTT: Okay. Yeah. I don’t have any questions. But I thought, maybe, we’ve got about three minutes, so if there was any concluding remark that you wanted to make or thinks that you think we ought to be thinking about as we try to smartly forecast within the community choice and the changes that are coming between, you know, investor-owned utilities, community choice aggregation, POUs, would love to hear it. And if not, that’s okay, too, but any concluding remarks for us?

MS. SIMONSON: I just want to thank you for inviting us to the table. It’s really exciting to be here and I think it’s really important to take -- to really utilize the CCA perspective on forecasting, especially as we’re forecasting forward innovative advances in demand-side resources, so thank you.

MR. ROSS: Thanks. I guess so one area that we didn’t really talk about or I didn’t talk about was efficiency, so I’ll just leave with that.

So one of the activities that we’re doing now is engaging with a third-party to evaluate our load on a meter-by-meter basis to look at kind of time-based efficiency opportunities and how we might run pay-for-performance procurements that are cost effective. So I like to say, I have a $6 million budget, but my procurement has a $400 million budget.

So the extent that we can create programs that are, you know, cost neutral or cost beneficial to our customers, then I get a lot more money that we can play with. So that's the intent of doing that baselining exercise, so that we can look at what those efficiency opportunities are.

And it's really not just efficiency. It's efficiency and DERs and what are the -- how's the time-based approach? Because flattening that load curve and matching that load curve to our procurement resources and the best resources and the most carbon-free resources that we have, I think that's the big challenge; right? So we are moving towards a carbon-free goal and you have a limited set of non-dispatchable resources and a very limited set of dispatchable resources. So what are we going to do to engage our customers in that journey? And the amount of, you know, flexible resources that are coming on in the form of electric vehicles and batteries, you know, that’s one wedge. But customer behavior and response is going to be another big one.

So again, I think you’ll find CCAs to be quite nimble and innovative in how we are reaching out to our customers. We each have a small set of customers that are geographically, you know, located. And you know, we are going to reach out and work with them quite collaboratively because they, through their elected officials who comprise our boards, are pushing us to go really hard down this carbon-neutral path.

And I will say, after spending 10 years at nonprofits and then 15 years -- 10 years in the private sector, it’s great to have a board that wants you to go faster down a path that we are trying to go to create carbon-neutral California. And so, you know, at my -- at our board meeting in June, they threw more money at local development. They said, “You should put more money to that,” and so that was great. And now we’ve got to figure out where to do it. And we’re probably going to use it for this RA program to go buy a bunch of flexible batteries. So we're quite excited to have that opportunity and that leadership from our boards.

COMMISSIONER MCALLISTER: Great.

VICE CHAIR SCOTT: Any last thoughts, Gary? Okay. All right.

Well, thank you very much Lynn and Rebecca and Gary and J.P. for an excellent panel. We appreciate you being here.

We will now turn to public comments. I don't have any blue cards, so I'm assuming there's no one in the room who'd like to make a comment.

Do I have anyone on the WebEx who'd like to make a public comment?

MS. RAITT: Yes, there's one person, George Nesbitt.

VICE CHAIR SCOTT: Okay. Is he un-muted or is he typing in?

MS. RAITT: I think we've un-muted him.

VICE CHAIR SCOTT: Okay.

MS. RAITT: Go ahead, George.

VICE CHAIR SCOTT: George Nesbitt, you are un-muted if you'd like to make your public comment please.

MS. RAITT: Oh, I'm sorry. I have not un-muted him.

Go ahead, George. If you were talking, we couldn't hear you.

MR. NESBITT: Can you hear me now?

MS. RAITT: Yes, thank you. Sorry about that. Go ahead.

MR. NESBITT: Yay, the joys. The joys of being on the phone. And I'm getting an echo, so you need to mute all the mikes on your end.

So George Nesbitt, residential energy geek.

Must of our discussion today has been around electrification. And I think that it is, in a lot of ways, the right answer, getting directed off of fossil fuels is absolutely necessary. It's also fraught with lots of issues and challenges. If we just electrify everything, we're going to add a lot of electrical load. You know, can the system handle it? Will we be able to generate it, especially considering our goals of renewable energy?

So a big question to ask is how does electrification actually support getting to a goal of high renewables and net carbon free?

But we're definitely going to have to focus a lot on reducing energy consumption, as well as load shifting is going to be so critical. You know, we can hope about batteries being cheap but I'm old enough to remember that they used to say that nuclear power would be so cheap it wouldn't have to be metered. And we know what the cost of that is and we can't afford it.

We're going to need to diversify our renewable energy mix because we are over-dependent on photovoltaics and the mismatch between when we use energy and when it's being generated. We already had, you know, just in a normal fossil fuel grid there's variations, seasonal and time of day. And with renewables, I think, that just becomes much harder.

In Tuesday's workshop someone from the ISO mentioned that the load profile has changed, and I don't think that's actually true. If the duck curve is sort of the non-eligible renewable load profile, and that has certainly changed, to the extent that the ISO total load profile has changed would only be a reflection of net metering. And so I think in total the actual load profile hasn't changed. And we need to really start looking at net metering the behind-the-meter and recognize it as a load, as well as a supply.

And so I think that will conclude it for now. Thanks.

VICE CHAIR SCOTT: Thank you.

Do we have any other public comment on the WebEx? Okay.

So with that, let me let Heather let you know about how to get the written comments, how and when to get the written comments. We look forward to hearing from everyone.

Go ahead, Heather.

MS. RAITT: Written comments are due October 10th. And the notice gives you all your information and it's up on this slide, too, as well. So I look forward to getting those.

Thanks.

VICE CHAIR SCOTT: All right. Thanks again to all of our terrific speakers and all the folks on staff who helped put this workshop together. And with that, we are adjourned. Thank you all for being here.

(The workshop adjourned at 3:35 p.m.)

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