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CALIFORNIA ENERGY COMMISSION

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	) Clean Energy
	) Interconnection
	) Electric
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COMMISSIONER WORSHOP ON THE CLEAN ENERGY

INTERCONNECTION - ELECTRIC DISTRIBUTION GRID

REMOTE ACCESS VIA ZOOM

TUESDAY, MAY 9, 2023

10:00 A.M.

Reported by:
Martha Nelson

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P R O C E D I N G S

10:00 a.m.

TUESDAY, MAY 9, 2023

MS. RAITT: Good morning, everybody. Welcome to today's Workshop on Clean Energy Interconnection with the Distribution Grid. I'm Heather Raitt. I'm the Director for the Integrated Energy Policy Report.

So this workshop is being held as part of Energy Commission's proceeding on the 2023 Integrated Energy Policy Report, or the IEPR for short. So I'll make a few logistical announcements before we get into the substance of this workshop.

Next slide. Actually, no, that's fine.

So this is a remote-only workshop. And to follow along, the meeting schedule and presentations have been docketed and posted on the CEC's IEPR web page. If you want to take a look there, you can download them.

Also, the IEPR workshops are all recorded and we will post the recording shortly after today and that will be linked to the website. And in about a month or so, we will have a written transcript of the day.

So attendees may make comments during the public comment period, which we'll have at the end of the day. Unfortunately, we have -- or fortunately, we have such a full day, we won't be able to take questions during the

workshop.

We also welcome written comments, and those are due by May 23rd, and the notice gives you all the instructions for how to do that.

So then finally, as a reminder to all of us today, if you could introduce yourself when you start to speak so that folks on the phone can follow along more easily?

And then with that, I'll turn it over to Commissioner Patty Monahan who is the Lead for the 2023 IEPR.

Thank you, Commissioner.

COMMISSIONER MONAHAN: Great. Thanks, Heather.

Well, I want to thank my fellow energy agency colleagues for joining me today on the dais. From the Public Utilities Commission, we have Chair Reynolds and Commissioner Reynolds. And I'm also joined by Vice Chair Gunda. And I see Commissioner McAllister popping up, so that's great.

I want to express my appreciation for my Advisor, Ben Wender, the Vice Chair Gunda's staff, to Heather and her team for organizing this series of workshops. They've done a bang up job and it's a packed agenda today.

So as I said last week at the workshop on the bulk grid, this year's Energy Policy Report is focusing on

speeding the interconnection of clean energy resources with the grid. This is a topic of keen interest, I would say, across all of our energy agencies, and also with California Air Resources Board. The Air Resources Board is setting stringent standards across all of the sectors. The one that I've been the most closely following is transportation. They're basically setting policies so that all vehicles transition to zero emission as soon as possible.

So the leading edge is cars for passenger vehicles, but we're seeing the same transition happening in the medium- and heavy-duty space where battery-electric vehicles and fuel cell electric vehicles are going to play a really critical role to meeting our clean air goals. And we need to, for battery-electric, plug them in as quickly as possible. We also need to produce zero-carbon hydrogen, which is going to take a clean grid as well.

So we need to plug in transportation at buildings to the grid as quickly as possible as we integrate renewables and storage at record rates. So we're focusing today on, as I said, the distribution side of the grid, the final stage of distributing energy to power vehicles, to power homes, to power industry, and pretty much many other end uses. And there's a lot of actions already being taken to speed the delivery of electricity to end uses. The

morning session is going to highlight those activities. And in the afternoon, we're going to look at ways that we can speed up processes.

So with that, I want to pass it over to Vice Chair Gunda to see if he has any opening remarks.

VICE CHAIR GUNDA: Thank you, Commissioner Monahan.

And I just want to, first of all, begin by thanking you for really conceiving a wonderful way of framing the IEPR and taking a fresh look at how we do this in a way that it's all California represented by all the agencies and we have a collective thinking of ideation on solving this really important issue on our path to meeting our climate goals.

To just inadvertently repeat a few things that Commissioner Monahan said, you know, I think our climate agenda has such a strong foundational requirement of a broad electrification strategy, you know, with an underpinning of having a clean grid. And I think in the last workshop last week, we really talked about the importance on the bulk grid, the transmission side, and how do we make sure we're cleaning the grid as rapidly as we can, and what are the different things we can do to do so?

And I think the second element of that electrification strategy is ensuring that we quickly

connect the electric load, making sure that we're transitioning away from fossils, especially as Commissioner Monahan pointed out, in transportation and buildings as a core strategy. How do we make this happen? But also an important element of this is how do we make that grid friendly?

So we are kind of talking about multiple pieces of ensuring this strategy moves forward. So I think, you know, this is a very important conversation, you know, a mirror image on the other side, and how do we tackle this on the distribution side and really evolve it to the next, you know, 50 years of grid needs for us?

A couple of points, I just want to synchronize with them. The distribution grid, especially given the opportunity to have most of the demand as a part of grid management, requires additional digging into in terms of how do we think about demand flexibility? You know, how do we ensure there is opportunity for connecting the load, but also ability to manage that load to be grid friendly?

And within that context, we have a couple of bills that passed last year, you know, 846, 205, 209, all kind of bringing the agencies together to think about, you know, how do we set those demand flexibility standards? How do we think about some of the reliability funding to help support the start of some of this work?

So I think this is a very important conversation and looking forward to it. And I'm really glad to be a part of this discussion today.

And again, thanks Commissioner Monahan, the IEPR team, the amazing Ben Wender, and all the staff who are working on all the stuff, so thank you.

With that, back to you, Commissioner Monahan.

COMMISSIONER MONAHAN: Thanks, Vice Chair Gunda.

Let me pass it to President Reynolds.

PRESIDENT REYNOLDS: Great. Thank you, Commissioner Monahan. And thank you, again, for taking the helm of these IEPR workshops, and also for focusing on a really important issue that we're facing today, accelerating interconnection to the grid.

I am looking forward to the discussion today. I welcome the opportunity to join my colleagues on the dais. And also wanted to make sure I passed along a sincere thank you to all the staff who put together the workshop and to all of the speakers on the panels today. We really appreciate all of the input and the work in making this happen.

I do feel encouraged by the conversations we had last week on how to improve interconnections to the bulk grid. It was a really productive dialogue. I appreciate the creative solutions that were put forward and the

acknowledgement of just the challenge that we're facing. So in that spirit, I'm also looking forward to the discussion today and hearing a range of stakeholder perspectives.

At the CPUC, we are also really focused on this issue, the issue of interconnection to the distribution system and, in particular, ways that we can improve how we integrate zero-emission vehicle adoption and increase load from distributed energy resources into distribution grid planning. And I would say that, you know, despite recent discussions and actions, this still kind of feels like a sleeper issue.

The distribution system is really critical to support our climate change goals. Everyone depends on it. There are millions of interconnections in California on the distribution system side. And it's critical to make sure we're planning thoughtfully, as well as implementing efficiently and quickly, and really always focusing on ways to reduce costs.

So with that, I did want to thank you again for having me today. I look forward to the workshop.

And I will turn it back to you, Commissioner Monahan.

COMMISSIONER MONAHAN: Thanks, President Reynolds.

Let me just go to Commissioner Reynolds, just to keep all the Reynolds together.

COMMISSIONER REYNOLDS: Thank you, Commissioner Monahan, and thank you for hosting this important discussion. I will echothe comments already made. I really appreciate the conversation we're about to have here today. You know, the one angle I'll add is that I can't agree enough that this is a really critical issue for us meeting our goals in the state. I'm the assigned Commissioner to the PUC's general rate case for Pacific Gas and Electric. During the course of our public participation hearings in that case, we heard from community leaders in both Humboldt County and in the City of Madera who expressed frustration at limitations on the development of their own communities based on limited capacity in a distribution system. It certainly would. And I appreciate how important it is for communities to be able to grow. And, you know, we often think about the importance of being able to connect to electrified buildings, electrified transportation.

It's also important for places around California to be able to develop new jobs, new hospitals, new services for their communities more broadly. And getting this right will be really important. It will be really important to balance the investments needed to connect new buildings to

electrify electrified transportation and buildings and be able to do so in a cost-effective way for all Californians.

So we look forward to the discussion we'll have today and thanks again.

COMMISSIONER MONAHAN: Thanks, Commissioner Reynolds. Yeah, I really appreciate that focus on if we want to make people's lives better, we need to build out housing as swiftly as possible. We need electricity to do that. So it's our clean energy goals and it's also just making people's lives better.

Let me pass to Commissioner McAllister.

COMMISSIONER MCALLISTER: Great. Well, thanks to all of my colleagues. I couldn't agree more with your comments.

And would again reiterate the thanks to staff in both your office, Commissioner Monahan and Vice Chair Gunda's office, and really across the Commission. I mean, it's really a moment of interconnection across many, many different themes, sort of integration of many conversations that traditionally have been kind of siloed. And I think that really comes together in this discussion about the distribution grid. I mean, with apologies to Shakespeare, the distribution grid is the thing; right?

And so I think that's obviously the grid up and down all the way up to the bulk power market, which we

talked about last time. We've known those are important and those are absolutely core planning for the sector that we oversee. But I think the distribution grid as an enabler of decarbonization, its role is just becoming more and more central to many of the discussions that we have across both of our Commissions.

I'm the lead on energy efficiency, buildings, and many things that touch the distribution grid. Vice Chair Gunda and I are working together on data support for really rising to the occasion to understand how to improve, how to understand how load growth, largely, but just the load itself is evolving as, you know, potentially a very powerful tool for managing reliability and our decarbonization journey in an optimal way. And, you know, I would just sort of highlight a few of the things.

On the load side, I mean, I really think that this distribution system discussion is vital because of electrification of transportation, the load growth we're going to see there, buildings, many, many loads coming on to the grid. And we need to develop the tools to have foresight about that and to have -- really approach planning in a much more atomized, localized, targeted, strategic way so that we can unfold the rates discussion that Commissioner Reynolds mentioned and all the sort of commensurate discussions together in a way that doesn't --

that in this strange transition period of a decade, decade and a half that's coming, that we can really manage customer costs and reliability and end up at a point B that I think we all understand is a much better place to be. But we have this sort of tricky transition to navigate in the meantime.

And so really looking forward to today, that's a great, great agenda. Wonderful, wonderful panelists. And, you know, highlighting the various sort of parallel efforts that are happening.

Vice Chair Gunda mentioned the load shift goal, which I think is a very key part of this. You know, we need to enable these new loads and a distribution grid to handle them in a way that creates much more visibility going forward for us as regulators, for the utilities, for the customers. You know, we have a lot of prosumers out there and we're just going to have more. And that's taking on a broader definition as well. It's not just about self-generation. It's about managing load and managing the footprint on the grid. And so customers will increasingly, in an automated way, hopefully, but they'll be taking a more central role in that with the help of third parties and, in many ways, with the help of regulations that we'll be promulgating on sort of governing individual loads and even individual devices, certainly in new construction.

So also, finally, I just wanted to mention, you know, we're making a lot of investments. The state is making a big push for equitable building decarbonization. And that's a great opportunity to support equity, to really focus on the parts of our society that need support the most, and also enhance our climate response, and all that takes place at the distribution grid.

So really vital conversation today. I'm just pleased to be a part of it and looking forward to the day as it unfolds, so thank you.

Back to you, Commissioner Monahan.

COMMISSIONER MONAHAN: Thanks, Commissioner McAllister.

So Commissioner Houck is in transit and she's listening in. I just want to read a brief statement.

So she wants to thank all the presenters. And she asked me to note that the topic of today's workshop is one, if not the most, critical issue we will be grappling with over the next decade.

So hopefully, we'll be able to see Commissioner Houck. I think she will be joining the visual virtual dais, but she is on the phone and hopefully we can have her ask questions even if she's not on the Zoom screen.

So let me turn it over now to my Advisor, Ben Wender, who's going to be leading us throughout the day.

MR. WENDER: Wonderful. Thank you all for those inspiring and compelling opening remarks.

We're going to start the day with some brief presentations. First, my colleague, David Erne, who is Deputy Director of the Energy Assessments Division, will kick us off contextualizing this year's IEPR and in some of CEC's ongoing activities and pointing towards some near upcoming events.

So David, take it away.

MR. ERNE: Thank you, Ben. Can you hear me alright?

MR. WENDER: Great.

MR. ERNE: So, hi, my name is David Erne. I'm Deputy Director of Assessments Division. I'm here with Chris Walker of GRID Alternatives as part of the opening context for the workshop today. So I'm going to give you some perspective about how this all fits into our IEPR this year, but also how it fits into state planning and the activities that we're looking at for improving interconnections across the board.

So as was mentioned, this is the second workshop in a series. We had our bulk system workshop last Thursday. It was a great workshop that talked about really the need for the resources that we have to bring online to support our reliability planning standards, the pace and

scale of bringing those online, the risks associated with getting those online and interconnected, but also walked through the process of interconnection, ongoing activities to improve interconnections, and talked about recommendations from developers and stakeholders about how to continue to improve that interconnection process.

We're following a similar flow today in terms of how we want to present on the distribution side. And we recognize as a conclusion of last Thursday, as was noted multiple times in the opening dais comments, the value and the critical function that distribution system interconnection of resources is to supporting reliability, supporting customers, and making sure that we can reduce our load at its source as much as possible, which is really valuable to our overall grid health.

So what I'm going to do today is I'm going to, first of all, walk through our schedule for the day, and then I'll talk through some context relative to state planning.

So next slide.

So like the flow of our last Thursday workshop, I'll be followed by presenter Chris Walker from GRID Alternatives who will give us a context of the value and importance of these grid connections to ensure that we provide customer support. We'll also go through a process

with the CPUC and utilities, giving us an overview of how distribution planning occurs and that phase in the overall process. That'll be followed by an overview of the actual interconnection process and the timelines associated with that, so what's typical that we see in terms of interconnecting distributed resources. Then we'll close out the morning.

We'll follow that up in the afternoon with developer perspectives, like we had on last Thursday, and an overview from a variety of stakeholders giving recommendations for improvements on interconnecting to the distribution system.

And that's the flow of our workshop today.

So let me put some of this in context with where we stand overall with the grid.

As I mentioned last Thursday, and I'll repeat today, over the last few years, we've seen a lot of challenges to the grid, primarily from the impacts of climate change that have caused us to have excessive heat events, have drought conditions, and also wildfires that affected our grid, and the need to ensure that as we move forward in our clean energy transition, that we are also taking into account these new conditions that we find ourselves in from climate change.

Next slide.

So in looking at the overall challenges for California reliability, there are three definite things that we feel are critical to ensuring that we achieve better conditions.

First of all is we need to improve our planning processes, incorporating climate change into our planning, both on demand and supply, making sure that we get our resources interconnected in a timely fashion and we have a sufficient number of resources across the entire state to ensure that we have those resources up and running as we need them, as are being ordered, so that we can maintain reliability.

But throughout that process in our clean energy transition, we also recognize we need to expand the diversity of resources available to us. On the demand side, clearly we're having a general trend towards more distributed resources being interconnected. We also need to -- we're also advancing through load management standards, appliances, a way to interconnect these devices in a way that's a smarter, easier way to bring them online and be able to take advantage of demand flexibility.

Also we need to diversify our supply side resources. We've seen some challenges in recent years on the supply chain issues for solar and storage. And part of overcoming some of those challenges is also making sure

that we're diversifying our resources to having a broader set of types of resources, including long lead time resources that will enable us to have a broader portfolio and less reliant on a few technologies.

And lastly, we need additional strategies like the strategic reliability reserve to support us during extreme events. We're going to have those. We don't necessarily need to buy all our resources through the RA Program, RAP, to ensure we cover every extreme event. That's not prudent. But we can have resources to provide those some grid reliability during extreme events through the strategic reserve.

Next slide.

So what has the state been doing to take advantage of all of our coordinated activities and our coordinated responsibilities? And that is working to ensure that we are conducting multiple reliability analyses, both -- I'm sorry, all three, CEC, CPUC, and Cal ISO, all conducting reliability analyses and evaluating different scenarios for the future for the state and coordinating on those activities.

We're also tracking our resources much more closely of those that are coming online, ensuring that they're coming online in a timely manner. And where possible, the state can act to overcome barriers to getting

those resources online that are necessary for some reliability.

We're also tracking our contingency resources, like the Strategic Reserve and other resources available to the state, to ensure that during those extreme events we have resources available to provide additional reliability.

We're also working to coordinate our activities along with Cal ISO System Operating Emergency Plan so that we are aligned with that and ensuring that during an emergency we're all operating in a similar fashion towards the same end.

And as has been noted before, we have real-time communications at senior levels, the folks that are on the dais, as well as others, brought together routinely for conversations for planning during the summer. And then as we have heat events, amping up that communication to ensure greater coordination.

Let me put this in perspective about the distribution system now.

We can go to the next slide.

Actually, this slide is mistitled. This should be solar rather than energy storage. I'll cover energy storage in just a second.

Let's take a look at data up to 2022 of what's currently on the system. And we look at, on the left, the

number of installations. The, primarily, major portion of that pie chart is the distribution system interconnection of solar relative to utility scale, which is the smaller numbers at the top. So look at the number of interconnections we've had on the distribution system thus far. It puts that in perspective that 99 percent of our solar connections have been at the distribution level and that's going to continue to grow.

On the right is the scale of megawatts. And not too bad, given that these are usually relatively smaller installations at the distribution level. It's still about 42 percent of our overall megawatts are at the distribution level. So we can see even up to this point, with the growth that we've had, we have pretty substantial amount of work that's happening at the distribution level and that's anticipated to grow.

Next slide.

Similar situation on the energy storage side, which is even more nascent, I would say, than the solar for interconnection, but about over 75,000 interconnections statewide of energy storage at the distribution level, which accounts for almost half of the, or a little more than half of the storage that we have in the state. So again, relatively large and growing. Let's take a look at what that growth is looking like.

Next slide.

Using our planning forecasts from the IEPR that support the IRP and RA, you can see how the growth is expected to continue moving forward for behind-the-meter storage and behind-the-meter solar, a pretty substantial ramp. So think of what we already have in place and that growing substantially over the ensuing years and what that means for the number of interconnections that are going to have to happen for solar and storage.

Let's take into account now what's happening on the electric vehicle side, so we can go to the next slide and look at the projection for the number of electric vehicles that are going to be put into the state over the ensuing years. And we can see how many millions of EVs are going to be there to charge, the number of charging stations that we're going to have to put in place to be able to support this growing number of electric vehicles.

So a growing number of solar storage and charging is going to have to happen in the interconnection associated with that. Quite a substantial workload for us moving forward to address that. And we'll talk a little bit later on today about what has to happen for the distribution planning process and what those interconnections really look like in terms of the actual activity that occurs.

Next slide.

We are working on other strategies to help support our reliability. The legislature asked CEC, as part of SB 846, to develop a plan for investing $1 billion to support reliability and clean energy. We produced that plan that's being evaluated for appropriation this year. Appropriations would be up to $1 billion over a three-year period.

We identified four funding priorities that we think are important to support us during this clean energy transition.

We have enabling investments, which are some of the administrative and capacity-building activities that need to occur, like incorporating climate change, engaging more with community-based organizations to ensure that we are planning out our resources in the right way to be the greatest support to the customers.

We also feel that there's a substantial amount of work we need to scale both demand and supply side resources and increase the diversity of those resources, as well as providing additional support during extreme events.

Next slide.

This simply gives you an overview of what was proposed in terms of funding. And I think really the critical point here is the priority, which is we feel that

the greatest amount of that $1 billion should go towards scaling new resources, both demand side and supply side, with demand side resources being the predominant investment that we think is valuable for the state moving forward.

That concludes my introductory comments and preparation for the workshop today.

I will point out on the next slide that we do have a workshop happening next Wednesday, May 17th. We'll have our Summer Reliability Workshop jointly with CEC, CPUC, and Cal ISO, where we'll review our anticipated summer situation, talking about hydro, fire risks, new resources coming online.

We'll also review our reliability assessments that the CEC and Cal ISO have conducted. We'll provide folks with an overview of where things stand with planning for the strategic reserve for the summer, as well as having a review of supply chain issues and an update on that from a panel of developers. So that's what's happening next Wednesday. Please join us. The announcement is out for that already.

So with that, I'll conclude my comments and turn it over to Chris Walker, who's VP of Policy and Programs at GRID Alternatives, who will give us some additional context from the customer perspective.

Chris?

MR. WALKER: Thank you so much, David.

Next slide, please. Next slide.

Good morning, Commissioners, agency staff, and friends. I appreciate the opportunity to provide some brief remarks as we work toward our next IEPR. I also want to thank everyone here and those who work to improve our distribution grid every day. Our work relies on yours.

As David mentioned, I'm Chris Walker. I use he/him pronouns, and I'm the VP of Policy and Programs at GRID Alternatives, the nation's largest nonprofit clean energy provider. And the irony of providing these remarks while hailing from GRID Alternatives isn't lost on me. Still, we've always needed a healthy grid to advance our mission, and it's an honor to be here with you today.

GRID is a staff of about 400, headquartered in Oakland, and it's our mission to build community-powered solutions to advance economic and environmental justice through renewable energy. Our work is exclusively for and with underserved communities, including low-income communities, environmental justice communities, and tribes, which we partner with and serve through our Tribal Program, as well as our Tribal Solar Accelerator Fund.

At GRID, we install solar storage and EV chargers with a big focus on workforce development, help to administer historic programs like DAC-SASH, SOMAH, CEC

Block Grant Programs for light-duty EV, charging infrastructure, and advocate here in California and nationally for equitable access to clean energy and mobility solutions.

Next slide, please.

So countless advocates have campaigned for decades for the scale of funding coming down the pipeline soon. Investments from the Bipartisan Infrastructure Law and the Inflation Reduction Act are just now starting to flow, with transformative implications for the future of infrastructure, solar, storage, EVs, and EV charging, efficiency-related manufacturing, and more.

And all of our targets are moving. Transportation and building electrification means exponential load growth amid shifts like robotics and automation, proliferating artificial intelligence, and internet-connected devices.

So these fundamental shifts in the way we power our society demands a healthy grid. Low-income homes and environmental justice communities can't go solar, swap out their internal combustion engine vehicles, or get EV chargers without sufficient distribution capacity, or do so efficiently or cost-effectively without sound interconnection processes.

We find purpose in our work partnering with and

serving California communities through these programs, and your work to ensure we can interconnect is instrumental. And as we try to do every day in our downstream work at GRID, I want to challenge all of you to think about how we can advance actively anti-racist and equitable improvements to our distribution infrastructure.

Next slide, please.

Next I want to talk to you about some themes we're seeing in seeking to interconnect our projects at GRID to California's distribution system. Low-income communities and communities of color in particular, which are disproportionately EJ communities, have outdated wiring, need main service panel upgrades, new transformers, substation upgrades, and more.

As for interconnection, there are appreciable differences across investor-owned utility territories, as well as rural electric co-ops.

But what is universally true is that we need to invest in staffing and process design within key IOU service planning, inspection, and interconnection roles. And GRID has advocated for dedicated staff for low-income and EJ communities to make sure this work can proceed at an equitable pace. They need priority.

At GRID, we've had the honor to advance access to solar through historic programs overseen by our partners at

the CPUC. The Single-Family Affordable Solar Homes, or SASH, Program and its successor, DAC-SASH, working in California's most pollution-burdened census tracts, are and will continue to be national models in providing no-cost solar to low-income families while advancing a diverse, inclusive solar workforce.

We're also very proud of our work on SOMAH, the Solar on Multifamily Affordable Housing program, which will install at least 300 megawatts of solar on multifamily affordable housing through 2030, reaching hundreds of thousands of Californians and covering as much as 91 percent of their electric bills if they're on care rates.

We're hopeful that equitable community solar will bloom, with work underway to build on the hard work done within the DAC Green Tariff and Community Solar Green Tariffs, with a new market-based program that can further align with federal funds while building additional capacity benefiting low-income Californians not served by other programs.

We're also excited about the future of SGIP and all it'll do to advance resilience in a solar plus storage future in California, especially its potential to help mitigate the net peak and ultimately contribute to local resource adequacy.

We're also excited about the increasing focus on

enabling technologies, like main service panels which we think of as the first interconnection, which are a major barrier to our work. So we applaud emergent programs like Southern California Edison's Home Electrification Readiness Pilot, which will help to address this key barrier for low-income homes gearing up for EV charging with co-benefits for solar plus storage projects too.

And these programs are just a sampling of California's investments, ones we're excited to build upon in partnership with all of you, in the communities who need and deserve these resources the most.

Next slide, please.

And interconnection matters. Through some of the programs I mentioned previously, GRID is proud to have installed over 25,000 grid-tied solar energy systems for low-income single-family homes, over 2,200 community facilities, including for multifamily affordable housing, helping our neighbors and communities to save over $650 million in energy costs in the process so far.

Next slide, please.

And while energy savings is the key benefit, it's not the only one. And installing those over-25,000 solar energy systems, we've provided invaluable hands-on training to over 30,000 people, helping to feed the demand in California for solar workers while advancing solar

workforce diversity in the process. The grid does and will continue to enable clean energy jobs in California, and we need a healthy grid for healthy job growth.

Next slide, please.

And though solar is how we got our start, GRID Alternatives is really proud to have grown our equitable clean mobility work. Because gas is still expensive and internal combustion engines are still a major source of pollution burdening our neighbors and DACs. So we know the road to healthier communities starts with infrastructure.

So much of our work now revolves around how we can help make sure California's clean transportation investments leapfrog the early equity missteps of our solar market.

To highlight a few, CARB's small but mighty Access Clean California Project created in response to the SB 350 Barrier Study and Report. It's a job in and of itself to know about the alphabet soup of programs, let alone navigate them as a low-income participants. So Access Clean California brings together many transportation equity programs into a single streamlined web platform with an integrated benefits finder that allows you to see everything you qualify for in one place, verify your income through a paperless process using an API with the IRS for both filers and non-filers, access a dedicated case

management team if you need them, and is supported by a statewide network of diverse CBO partners that do culturally and linguistically appropriate outreach.

We also partner with CALSTART to administer the CEC's Communities in Charge Project too. It incentivizes equitable deployment of Level 2 chargers, prioritizing multifamily affordable housing, tribes, places of worship, schools, health care facilities, and more throughout California.

And at GRID, we're dedicating to stacking and co-leveraging across this complex ecosystem of programs to maximize benefits to participants in an efficient and cost effective manner. For example, we've worked to ensure that SOMAH properties have a streamlined application process for Communities in Charge and that those properties planning to install solar can get a larger system if they're also installing EV charging infrastructure.

Meanwhile, we also want to make sure that SOMAH tenants know about Access Clean California and can find EV rebates and assistance programs when the stars align and relevant programs are open and funded.

Next slide, please.

And before I run out of time, I want to leave you all with some strategies we think about as we scale our efforts for equitable access to clean energy and

transportation solutions. None is more fundamental than ensuring we can interconnect.

We can also begin to align renewable energy and transportation equity programs to provide distribution system benefits.

Let's ensure we leverage the power of California's ecosystem of CBOs who keep us honest and ensure our work and ensure our solutions work for their communities.

We can further harness solicitations, terms and conditions to strengthen alignment across programs and advance procedural equity.

Make sure that programs can more easily stack and talk to each other.

Expand categorical and co-eligibility.

Make sure our most underserved communities have the capacity to access technical assistance through planning and participation grants.

Ensure we're thinking beyond savings and creating career opportunities and opportunities for minority-owned, women-owned, veteran-owned businesses.

Share data across programs to make collaboration easier and dollars go farther.

Ensure our lowest-income folks are first in line and get the most support within our incentive programs.

Ensure program administrators can be more agile at adjusting program designs that aren't working or need tweaks to boost equity outcomes.

And ensure we're designing California's efforts to align with the historical federal resources coming down the pipeline that our taxpayers have already paid for.

Next slide, please.

Finally, I want to thank the Commission again, as well as the entire community of practice here, for its work to make sure that these historic efforts and this historic moment have lots of room for growth to be as efficient distributed distribution capacity and interconnection. If we have intentional planning and continue to prioritize improvements intelligently through this IEPR, we'll have a sound foundation for ensuring equitable climate action as well as healthy, prospering communities for all Californians.

Thank you and back over to you, Ben.

MR. WENDER: Thank you so much, Chris and David, for those wonderful framing comments.

I'm going to pass it on to Commissioner Monahan and the dais and look forward to some discussion about how to harness these historic resources, the projected growth in both new distributed energy resources and flexible loads and how to do it equitably. Thanks so much.

COMMISSIONER MONAHAN: Alright. Thanks, Ben. And I think for us, we have a little bit more than ten minutes for questions or comments from the dais.

I'm going to just start by saying thanks, David. I thought that your presentation was excellent and really highlighted how, in terms of just numerically, how much more challenging it is on the distribution side to work through processes.

And Chris, I want to thank you and GRID Alternatives for all the work that you do. Your organization is really amazing. And it's wonderful to see all the places that you intersect with our work and as you've expanded into transportation. And I, too, have intersected more with GRID Alternatives and it's great to work with you.

So I wanted to ask Chris whether, and just kind of taking a step back, about whether -- I think you've had more experience on the solar side, so maybe you could just focus there -- on whether you have seen any like positive changes or whether your experience is it getting harder? Just from kind of an anecdotal, not necessarily a number of functions way.

MR. WALKER: Thank you for the question, Commissioner Monahan, and for your recognition of GRID's work in this space. We're happy to partner with you all.

I think there, as I mentioned, there's a lot of variation across what we see in terms of interconnection processes and challenges across the investor-owned utility territories. But there is listening, and our partners at the CPUC help to work with us when we do encounter the stickiest interconnection challenges. That said, some of the processes are extremely finicky. Having a customer name on a bill vary by one character can derail the interconnection process in ways that can add a week or more to the timeline. So we are, with different investor-owned utilities, requesting different kinds of changes.

But in general, our projects, which are on the smaller side, have somewhat of an easy path if the paperwork is complete and accurate. So I do appreciate our utility partners for that work.

That said, the coming scale of investment, as I mentioned, is so great that we all will have to redouble our efforts in capacity and make sure that that can continue to be the case while making process improvements to further sort of smooth the path.

COMMISSIONER MONAHAN: And I'll ask my fellow participants on the dais, if you have any questions or comments, you can raise your hand or you can just take yourself off mute and you can speak. Well, I'll ask one more.

You had recommended that there be dedicated staff for low-income communities. Can you talk more about what that looks like?

MR. WALKER: Yes. The service planning queued interconnection processes have their own sort of sorting methodology. And it's not the case that low-income and EJ communities have any different differentiated sort of access to these processes, while equity, by definition, implies preferential treatment to sort of remedy the fact that these communities are starting from a different starting point than other communities with regard to their infrastructure.

So in terms of our goal to increase equity, we've requested that preferential treatment, and we haven't seen that. It's not actually allowed under current process. But we're going to continue advocating for that because, again, we can't have an inclusive transition to renewable energy. We can't help low-income and EJ communities transition to electric vehicles and make sure they have charging infrastructure locally if their infrastructure is at a disadvantage.

COMMISSIONER MONAHAN: And what do you mean, they're not allowed to?

MR. WALKER: I'm not sure if that's regulatory or legal, but the service planning process for utilities is

rock solid. And they've noted to us they can't, you know, have low-income applicants or EJ applicants skip the line. That's just not how it currently works.

So I'm far from an expert on that policy matter. But it's worth looking into on our side and we're tracking relevant pieces of legislation to see if there are opportunities to change.

COMMISSIONER MONAHAN: Thanks.

Commissioner McAllister?

COMMISSIONER MCALLISTER: Yeah. Thanks. Thanks to both Chris and David.

Chris, in particular, you know, I'm very familiar with GRID Alternatives from the very early days. And just really, it's been great to see you grow and thrive and just do amazing work. So just kudos to you and the whole team.

I want to just ask if you have any observations from your experience with solar, and now transportation primarily, as we move into this rapid electrification of buildings, any lessons? Energy efficiency in buildings and, you know, sort of integrated home upgrades and things like that, they are somewhat more complicated, but they are, you know, they need to be integrated with all these other activities. I guess any observations or challenges you might raise or sort of suggestions you might have for how our under-resourced communities can best be approached,

how programs can best approach our under-resourced communities to really effectively, efficiently and kind of urgently address the broader buildings related upgrades that we'll be doing?

MR. WALKER: Thank you for that question. It's a really important one and one we think of a lot. And I tried to cram a lot into that final slide but could write a doctoral thesis on all of our program design ideas that we think can further advance equity and inclusion in this transition to renewable energy and clean transportation solutions.

What we feel is one of the emerging themes is the need to have a more integrated approach to service delivery. If we can conduct outreach to a home and tell them in one go about solar programs, storage programs, EV charging infrastructure programs or programs that can help them get subsidized charge cards, access incentives for electric vehicles, and potentially financial assistance in the form of low-income loans or financial counseling to access EVs, we reduce the burden on that applicant to be able to access those programs without, again, learning the entire alphabet soup of that entire landscape of programs, which is overwhelming and a barrier of participation. If we can then deliver those services in a fell swoop, it actually helps those individual programs to be more

effective.

So, one of the examples I provided is, for example, if we can approach a multifamily building and tell them about EV charging infrastructure at the same time as solar, pairing both Communities in Charge and SOMAH, they can actually get a larger solar energy system through SOMAH to account for the load growth that will happen due to that charging infrastructure. So stacking, coordinated co-marketing, co-leveraging across programs is one of the important themes I would point out there.

COMMISSIONER MCALLISTER: Great.

MR. WALKER: And then, on the agency side, again, leveraging the power of solicitations in terms and conditions to be specific about expectations in that direction, that programs will stack and co-leverage and talk to one another and sort of smooth the path to facilitate that to happen kind of from the beginning through program design and requirements from them.

COMMISSIONER MCALLISTER: I appreciate the answer. I guess I'll just note that you didn't mention heat pumps at all or efficiency measures or any of the things that we're going to be investing, you know, a billion-plus dollars in in the coming couple of years. So, you know, you mentioned batteries and EVs and solar, but not the actual core electrification that we're going to be

doing in terms of the actual and non-EV end uses in the homes.

So I'm just wondering if you have any suggestions about those programs that are coming down the line and how they might be integrated? I don't want to take up too much time here, but that was sort of the gist of my question and sort of broadening to a more integrated building upgrade, you know, integrated building upgrade approach.

MR. WALKER: Yeah, and you've pointed to one of the blind spots in our work. At GRID, we don't do electrification beyond main service panel upgrades and solar. That said, we want to make sure that we're mitigating load before we install solar. So lots of our programs co-market with ESA, for example, and we're looking at the ESA Whole home program, for example, as one way of addressing the fact that under NEM 3.0, we'll have a different financial value proposition per homeowners. So if they can participate in the ESA whole home program at the same time as going solar through DAC-SASH, it can make their bill credits go farther.

So the same comment stands around stacking and co-leveraging, integrating everything that I mentioned, in addition to building electrification efforts, weatherization efforts, efficiency efforts, et cetera. That's just not a big part of our work at GRID, and we're

not going to be installing heat pump water heaters anytime soon, unfortunately. We're just not well positioned to do that.

COMMISSIONER MONAHAN: Well, Chris, I want to move us along so we can make sure we stay on time, but thanks very much to you and to David for your comments. And Chris, I would encourage you to submit to our docket any best practices that you have seen, you know, across different utilities. I think it would really help us in terms of just highlighting kind of what's working and where we might want to look for replication.

MR. WALKER: Thank you, Commissioner Monahan. We'll do that.

COMMISSIONER MONAHAN: Thank you.

Alright, I'm going to pass it back to Ben.

MR. WENDER: Thanks so much, Commissioner, and both Chris and David, again for that compelling introductory framing.

Our next panel is going to dive in a little more to the process of distribution system planning. We'll hear about some of the great work ongoing at the Public Utilities Commission to prepare us for rapid growth in distribution-connected resources that we heard about just now from David. We'll also hear a joint presentation from the joint IOUs about how they approach distribution

planning, as well as a publicly-owned utility, get a sense of how their processes complement, are similar or different.

So let me open it up, start with Simon Baker. He's Director of Distributed Energy Resources, Natural Gas, and Retail Rates at the California Public Utilities Commission.

Simon, take it away.

MR. BAKER: Hi. Good morning, Commissioners and fellow panelists, workshop participants. I'm grateful to be here.

I was asked to provide an overview of the investor-owned utilities distribution planning processes and some of the PUC's activities in this space. For reference, the utilities serve about 75 percent of the electric load in the state and they're, obviously, represented on the panel here as well. We'll be hearing from them.

Next slide, please.

I thought I would begin with some key concepts here. When someone wants to connect to the distribution grid, they either come through the process that guide interconnection or energization. And it's important to clarify this terminology and the distinction between the two.

Interconnection is for behind-the-meter generation or storage resources and this is governed by electric rule, the Electric Rule 21 Tariff.

Energization on the other hand is for new customer loads such as new housing or commercial development or to connect new electrification loads such as electric vehicle service extensions. These are governed by several different tariffs including Electric Rules 2, 15, 16, and for EV service extensions Rule 29 or 45 depending on the utility.

The vast majority of requests to come into these processes are able to connect to the grid without requiring upgrades to the distribution grid, at least for now.

If upgrades are required, then that goes into the utilities distribution planning processes. Distribution projects or solutions are defined on various time scales and I'm roughly categorizing these into three buckets here. They vary by utility and I imagine they can probably refine.

But to kind of simplify, you've got simpler projects such as reconfiguring circuits or installing secondary transformers that can happen in kind of the months to about two years timeframe. You've got more complex projects, such as building new circuits or adding or replacing a substation transformer, and these happen

kind of in that three- to five-year range. And that out to five year range is really the focus of distribution planning to date. Then there's the most complex projects which involve substation expansions or new substations. These can take much longer beyond the five year planning horizon, which is more typical of the utilities planning processes.

Next slide, please.

In 2013, new legislation was enacted pursuant to AB 327 and the PUC opened the Distributed Resource Plan, DRP, rulemaking and implemented a series of decisions that changed how the utilities go about distribution planning. The objective of the DRP legislation is to minimize system cost and maximize ratepayer benefit from investments in distributed resources.

But to do that, the PUC needed to put in place various frameworks to increase transparency, oversight and stakeholder involvement in distribution planning. And among them were a requirement to use the CEC's IEPR demand forecast as an input or importantly, in the alternative, the utilities can seek an approved deviation from the IEPR forecast through an advice letter filing. Heretofore, the utilities have not done that.

A framework for distribution investment deferral, called the DIF, was also implemented and this is where DERs

can be used as alternatives to traditional wires infrastructure.

Also, new data is made available publicly through a public data portal so that developers, tribes and local governments can have better information about the condition of the grid where they may want to connect.

The utilities were also required to conduct integration capacity analysis, or ICA, to assess the amount of available capacity on the grid at a circuit level for new resources or loads to interconnect. And that information is made available on the public data portal.

And also, these new processes were linked to the general rate case process where the utilities received cost recovery for the ratepayer dollars needed to maintain and expand the distribution grid. And the PUC is continuing to refine these processes through a new rulemaking, the high DER rulemaking, which I'll elaborate on a little bit later.

Next slide, please.

So this is how the current distribution planning process works, at least in concept. And I know this slide is -- there's a lot going on here, but I thought it'd be helpful to see how all these pieces fit together from a timeline perspective.

First, it's important to say that the IOUs own and operate the distribution grid under a construct we call

the regulatory compact. Essentially, that means that the IOUs, as public utilities, must provide safe and reliable service. And in order to do this, they are provided a reasonable rate of return on the investments that they make for their investors and on behalf of ratepayers.

Within this, the IOUs are responsible for managing uncertainty looking out over the planning horizon. And the utilities have an obligation to serve, which means that they need to plan for new loads coming onto the grid. And the grid assets that they invest in using ratepayer monies must be used and useful in order to recover these costs and rates. What this means is that they seek to build these grid assets in a just-in-time kind of way as they are needed. In other words, not building out parts of the distribution grid where the load isn't actually realized, because that would be a poor use of ratepayer dollars.

So how does this process work?

It begins with the various inputs to the IEPR Forecast. And these include reasonably-expected-to-occur policy drivers, such as energy efficiency, rooftop solar, building electrification, and new ZEV regulations. The IEPR Forecast happens annually. And the forecast feeds into the utility's annual grid needs assessment or GNA, which identifies distribution system deficiencies to

determine those grid needs and also looks for no cost solutions through potential load transfers.

One of the challenges the utilities need to work with is that oftentimes they must reconcile what are called known loads with what is in the IEPR Forecast. Known loads are basically projects, new developments that they know are coming onto the grid in the short term, in the one- to three-year timeframe out, for example. And the IEPR Forecast inputs for those first few years may or may not perfectly match up to what they are seeing in terms of those known loads. And the utilities have different ways of dealing with that. And it's an issue that we're looking at in our proceedings.

The GNA then feeds into the annual distribution deferral process where the utilities prepare what's called a Distribution Deferral Opportunity Report, or DDOR, which identifies planned distribution upgrades and candidate deferral projects for DER alternatives. These non-wires alternatives can typically be used within like a three- to five-year out time horizon where the projects are certain enough in terms of the need, meaning they're not further out than five years, but the need is not too soon to allow for the DER procurement to occur. And this can be thought of as kind of like a Goldilocks zone of sorts. But because of these narrow attributes, a vast majority of the projects

are not deferred to DERs. They're done through more traditional alternatives.

So once the need is defined, the utilities implement the solution. And as I said, the focus is really mostly five years out. But new ZEV policies are challenging this paradigm. And the utilities are actively working, and we're working with utilities, to figure out how our processes need to adapt.

And all of this then feeds into the general rate case process, which sets the budget for cost recovery. And that rate case process happens every four years.

Next slide, please.

So looking at how this fits into the utilities current GRC process, as previously noted, the utilities, they operate on a four-year GRC cycle. And at present, PG&E and San Diego have GRC filings before the PUC, which were filed in 2021 and 2022, respectively. And Edison will be filing its GRC this month.

So as previously mentioned, the IEPR process includes a reasonably-expected-to-occur forecast of load modifiers, such as electrification policies. And there were some big changes that happened in 2021. The CEC, the PUC and the CAISO collaborated to develop an Interagency Electrification Working Group that would take in scenarios looking at future electrification. But a key distinction

here is that, really for the first time, some of the proposed not-yet-adopted regulations were included here. And this is kind of a point of departure from how prior forecasting is done.

And so now in the 2022 IEPR, we now have a new managed forecast, which includes a whole host of different CARB policies for electrification, some of which are not yet adopted. And so that's a new input that's coming into the Edison GRC process for the first time.

Next slide, please.

And just to see how this kind of fits into the IEPR Forecast, this slide basically just shows how from the 2021 to the 2022 IEPR, what the growth in the forecast was due to this incorporation.

Next slide, please. I'm going to go over this slide. Go to the next slide, please.

So I want to just give a brief overview of some of the things that are underway. So in the high DER proceeding, it's currently scoped to look at how we can better prepare the grid and distribution planning process for high electrification. It's also looking at what is the appropriate cost recovery venue? Should we continue to do cost recovery in the GRC or other venues? We're looking at how the IEPR process and the grid needs assessment and the GRC alignment, whether there's any tweaks to that that need

to happen.

And we're also looking at how the utilities are engaging externally with tribes and local governments and developers to do more effective load planning. We have a consultant study that's underway on electrification impacts, and we anticipate that that will be released soon.

Another big initiative is that we have a freight infrastructure planning framework that we're working on. This is an interagency collaboration focused on medium- and heavy-duty electrification. We'll be having a workshop soon on this process. And the objectives of that really is to come up with a process for common inputs and assumptions on these sources of new electrification load growth that could be used in the IEPR, the distribution planning process, IRP, and the GRC. And this would be a process that we hope would be useful and informative into the IEPR process, as well, in terms of demand scenarios.

And this process is also intended to be able to identify where there are zones on the grid that are ready to electrify, and then also where would be the highest priority zones for long lead time infrastructure to be developed. We're talking about in that seven- to ten-year timeline.

And then finally, we have what's called the integration capacity analysis. I was talking about that

earlier. It's available on these public data portals. A lot of work has been done to develop that and to refine that and make it accurate and available for use on the generation side on the load side where there are a number of refinements that are underway for it to be more useful for planning on the load side. And the objectives of that work are to really streamline energization applications to reduce the timeframes and increase the certainty of those data and to facilitate the siting of EV charging infrastructure.

The utilities have a number of refinements that are underway to make that ICA load data available. PG&E has a timeline that's out to towards the end of 2024 on more of an accelerated timeframe, SDG&E in the third quarter of 2025, and Edison fourth quarter of 2026.

So I'm happy to take questions as we close. And thank you for your time.

MR. WENDER: Wonderful. Thank you so much, Simon, for sharing that exciting ongoing work at CPUC.

I'm now going to turn to our colleagues for a joint utility presentation. Mark Esguerra, who is Director of Distribution System Planning and Strategy at SCE, will be presenting and we'll have Satvir Nagra, who's Director of Asset Planning with PG&E, and Matt Belden, Electric Distribution Planning Manager with SDG&E, available for

questions.

Mark, thanks for joining and take it away.

MS. ESGUERRA: Thank you for that introduction.

And thank you, Commissioners, for allowing us the opportunity to brief you on our distribution planning process. As mentioned here, this is a joint utility presentation with SCE, PG&E, and San Diego Gas and Electric.

Next slide.

So we're going to get into our distribution planning process, but before we do so, if you go to the next slide, we want to give you just a brief overview just to set some context here about where on the grid we're looking at planning here.

So as you can see, you had a prior workshop on our transmission system so you can get oriented on what we're focusing in on here. So our distribution planning process is really focused there in kind of that greenish box in the graphic out here. Specifically, it's focused on the distribution substations and the distribution lines that eventually make their way to supply power to our end-use customers.

As you can see upstream, it connects to our transmission system. And largely, for the joint IOUs, their transmission systems are not part of the distribution

planning process with exception to SCE, where we do have our sub-transmission system, which is part of our CPUC jurisdictional facilities.

Our distribution systems are anywhere between 33 kilovolts down to as low as 2.4 kilovolts, but the bulk of most of the utilities' distribution systems is around the 12 kV portion here.

Next slide.

So from here, very similar to what Simon had provided in overview, our distribution planning process here is an annual process that the joint utilities perform respectively for the each utilities. There's a lot of different things that go into it. It is a very dynamic process that is factoring in near-time interconnection requests to inform our forecasts. And so it all starts with the assumptions of the projected outlook of the demand, as well as generation that's going to be interconnected on our distribution system. And that really sets forward the initial forecast development phase.

From that, it moves into the assessment phase, where we are assessing what our grid is going to need to meet the projected demand. And we do look out, you know, there's a huge emphasis over the next three years, but we look five and even ten years out to understand where our grid is going to require upgrades or retrofit.

After completing that grid requirements, then we move into mitigations, evaluating different types of mitigations that would be preferred for our distribution grid, which is then fed into our respective investment plans. And as you can see, the process then is cyclical. As we get more information about where demand is going to be placed at, where generation is interconnected, or other items, that feeds back into our process of our forecasting and development and development of our what we call our base cases to better understand how our grid is going to evolve over the next several years.

Next slide here.

So from the forecast development aspect, it really all starts with the information we have from the Integrated Energy Policy Report. We use information from the IEPR to inform where we're going to see the growth on our grid. So using that, as well as information that our respective utilities will have more from a local level, looking at historical area loadings, different economic indicators, as well as temperature, to better understand, you know, where that growth is going to occur. So it's really this top-down view, marrying it up with the bottom-up view from the utilities.

From there, we'll look at it from -- most of our systems are summer peaking, so we'll look at it from a one-

in-ten year temperature adjusted load forecast. And then from there, we'll account for other lows that may not have made it into IEPR such as some of the more recent interconnection request to help shape and inform where, when, which parts of our grid are going to see that demand.

From the DER side, we also use the CEC's forecast for DER growth disaggregated down to our circuits and substations. And what's really important here as we start to, you know, advance further in our in our planning is understanding what the different hourly profiles are for these different DERs. And the DERs include solar, energy efficiency, demand response, storage, as well as electric vehicles. So you have DERs that can either consume load, as well as help decrease load in our system, so all that is put into play into our overall forecast.

Other things that we are involved in here is, on an annual basis, there's a Distribution Forecasting Working Group where each utility will share kind of their information from the IEPR, get alignment from this working group on how to disaggregate that that load, so it's done in a in a stakeholder forum.

Some things here to point out is that the CEC has made some significant enhancements to their IEPR methodology, particularly raising kind of the 2022 forecast compared to the 2021 forecast. It factors in the various

transportation electrification, TE, and the building electrification policy objectives, which is definitely going to show up on our system to help us better identify where and when we're going to need additional infrastructure to meet that projected growth.

And so this is a lot of the things that are going on in the forecast space.

I will say for Southern California Edison, since we are in our rate case filing cycle, we've also factored in a transportation electrification grid readiness forecast that happened prior to this 2022 IEPR, which aligns pretty closely with what we're seeing here. And it was one way for SCE to be able to plan for additional facilities prior to some of these forecasts as being updated and revised.

Next slide.

And so once the forecast is dialed in and spread out through our grid, we now have -- we move into our assessment phase and really focused in on where are we going to see additional need for capacity, and so we've been calling that determining what the grid requirements are. So we'll look at the projected demand and DER forecast and its affect on the existing grid. And we're really focused on trying to ensure that the grid is safe and reliable to meet our customers' needs.

We're also looking at projects that we've already

approved and have those modeled into our systems to understand are those projects still sufficient? Are there additional enhancements needed on those projects?

And then we're also looking to ensure that we can operate the safe transfer of demand under various emergency conditions. So we'll study our system to understand, you know, during certain contingencies, are we able to serve it from different parts of our feeders?

We'll factor in the different geographical load and customer mix to see how that varies in terms of the demand. And that goes back to the forecast, understanding the diversity of when the load peaks. And we may look at other scenarios.

This is very local knowledge, too, as well. So the help of our local system planners that are closer to boots on the ground where the requests are can help us calibrate our results to see, is it aligning with what we have been seeing in the past.

Particularly, we are focused on trying to identify our equipment when our capacity is expected to be exceeded, and we've been calling that thermal capacity needs, as well as ensuring that we have good power quality and voltage. So that's really important for, particularly, with our customers having more sophisticated devices, the quality of power, the stability of voltage is going to be

really important, so we check for those as well. And we identify if there's going to be additional grid upgrades to be able to comply or have our grid meet those needs.

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After we've completed our assessment, we take a look at all those grid needs and we start evaluating, what are the various options we can go about, you know, upgrading our grid? And as was mentioned earlier, for all the utilities, we try to focus on what are some of the no cost options first? How do we take advantage of the existing grid? And a lot of that work is through the work of our distribution system planners, our distribution operating engineers, understanding are switching solutions going to be effective? What does that look like? Are there some smaller upgrades that we can do to transfer a load between feeder and other feeders to be able to meet the projected needs?

Once those are exhausted, then we start looking at are there incremental upgrades, smaller-scale upgrades that could serve kind of the load? And then from there it progressively goes into larger upgrades such as are there going to be a need to build new distribution lines or increase the bank or capacity size at our substations, as well as are new substations going to be needed here?

And then the other area that we'll look at, once

those options are identified, we'll also try to understand, are there DER solutions that can help us defer some of these upgrades for a later timeframe?

So some of the things that we're really focused on here as we go about that is obviously cost effectiveness is really key, but also ensuring that whatever upgrades we do recommend that it does have a plan to meet all requirements that are needed so to ensure that we have safe, reliable, high quality of power for our customers there.

So things that when you look at roughly, from a timeline perspective, some of the different upgrades that are involved, you saw this earlier in Simon's presentation, some of the smaller upgrades can take anywhere between one to three years, but the medium-size upgrades, new feeders, increase in capacity size, infrastructure takes time to build. So we're looking at potentially about three to five years for those upgrades. And then some of the larger type facilities that could require significant types of permitting or review from the large to very large can vary anywhere between four to six years, and if it's larger substations, in some cases it could be roughly seven years plus.

And so these are things here that as we are building our grid and factoring in these large

transportation electrification loads, building electrification loads, it becomes ever more important for utilities to get some of the information early to start that process and to start the deployment of some of this infrastructure.

Next slide here, which leads into kind of like some ongoing improvements. So some things that all three utilities are working on and we're looking to further enhance and improve in this area is how do we engage some of these customers earlier and often, particularly from a transportation electrification side, engaging with our fleets, our ag customers, those customers that are electrifying to help understand what their multi-year forecast is going to be? And from that, really, that can help inform our forecast, along with the information we have from the IEPR, so that we can start proactively planning for those facilities.

We're also looking at how we leverage some of the existing outreach efforts we already have today with communities and customers so that we can collect some of that information early on to build it into our plans.

We mentioned this earlier, some other improvements, the work that the CEC has done on IEPR I think is fantastic. We're seeing that is helping us kind of build out.

The other area that we're looking at is how do we find ways to continually look to improve the tool sets that our distribution system planners have? And we'll hear a little bit more about this as we get into the interconnection side, as well, but this is true for planning, simplifying our ability to identify where and when growth is going to occur as well as processing our interconnections.

And then, you know, looking at how to leverage some of the integration capacity analysis information to help identify where are there capacity opportunities on our grid? And then things that we talked about is load management to help bridge the gap with some of our larger interconnections. How do we take advantage of those type of solutions and where the utilities can also, you know, start to better orchestrate the flexible loads and resources to really help optimize the capacity that they have on their grid?

I know I'm running out of time there, so from there I'll hand it back to you, Ben.

MR. WENDER: Wonderful. Thank you, Mark. Incredibly helpful overview and rich context for discussion.

Next I want to invite Harry Marks, he's Manager of Distribution Planning with the Sacramento Municipal

Utility District, to share their approach and some of their upcoming initiatives.

Take it away, Harry.

MR. MARKS: Alright. Thank you, Ben.

And thank you to the CEC and Commissioners and staff for the opportunity here to share SMUD's Clean Energy Plan and how our distribution planning process supports that.

So next slide. One more. There we go.

So SMUD is the sixth largest community-owned utility in the country with over 75 years of service. We frame every issue in the local light, which means our customers and community are the heart of everything we do. Keeping the lights on and our rates affordable have always been two most important things to our customers. Our customers also expect us to be responsible stewards of the environment and was part of what led us to really focusing on a clean energy vision.

So next slide.

When we talk about our clean energy vision, we came up with a SMUD Zero-Carbon Plan. And so the plan focused on four main areas, which are shown in this slide.

The first is our natural gas generation repurposing and retooling. You know, based on our reliability studies and overall grid impact, we'll evaluate

our existing gas generation plans for potential retooling, refueling, or replacing with renewables.

You know, our second goal there is proven clean energy technology. These are resources that are already in our portfolio like wind, solar, geothermal, hydro, biomass, short duration battery, electrification, demand response, and all those. These proven technologies will get us 90 percent of the way to our zero-emission goal, and that includes the 3,000 megawatts of renewable storage that we have planned, including the 1,100 megawatts that we plan to have online in the mid decade.

As you can see by this slide, these first two work streams account for about $2.5 billion investments.

The third is our new technology and business models for potential partnership. The biggest challenge will be closing that remaining ten percent gap. This includes working with our partners in researching, piloting, and bringing new technologies to scale. This work will help us identify potential partnerships and business models like virtual power plants and launch pilot programs to test emerging technologies. We plan to invest around $2 billion in the new technology and business space through 2030.

Then our final work stream is our financial and regulatory strategy. This will focus on the estimated cost

range and associated rate impacts, which we're doing everything to minimize for our customers. We know there are new technologies out there that aren't market ready now but do show a great promise for the future. And so for us, at our standpoint, there's no solution that's off the table. We're wanting to look at all these as far as opportunities.

Next slide.

So moving to SMUD's specific distribution planning process, our primary goal is to ensure SMUD's distribution system has sufficient capacity to safely, reliably, and cost effectively serve our needs of our customers.

So our distribution planning assessment starts with our ten-year integrated forecast that includes load like building electrification, normal load growth, our EV forecast, the impact of DERs. We also include our local jurisdiction’s general plans and specific area plans, tentative maps, customer development plans, our own system criteria, our planning criteria, and historical performance, and all that goes into our assessment. The team works through those. They model all our circuits. Through that process, they identify where we have deficiencies, and that rolls into our five-year Capital Investment Plan.

Next slide.

I wanted to talk about our forecasting here just briefly. So our forecasting is typically about one percent growth as far as our annual load growth, that's our unmanaged one-in-ten weather scenario, and that's based on SMUD's internal load research and forecast. We define a one-in-ten scenario as 110 degrees is the high, and then the low being above 70 degrees for multiple days. So the scenario includes our core load growth, our incremental and new large commercial loads, building electrification, which at this point we spread evenly, as well as electric vehicles, we spread that growth evenly across our system, and then our DERs that we have mapped into our system.

Next slide.

So our planning criteria, first we make sure that we can serve the load. So under peak conditions, we want to make sure that none of our facilities exceed their normal rating. And then under emergency condition, like an N-1 scenario, we can bait (phonetic) and restore all the customers and not exceed the emergency rating of the equipment. We want to make sure our design of our system is flexible. We have strong feeder ties, so we can switch load for clearances or to restore customers after an outage.

From an efficiency standpoint, we want to make

sure we maintain the efficiency of our system and try to run it near unity power factor at the distribution system level.

And then stability level, we want to make sure that, you know, we're maintaining service voltages and power quality within the ANSI standards.

And on coordination, we want to make sure we install these facilities as development is occurring. We want to coordinate our capital investments, also taking account when we have aging infrastructure replacements that we're upsizing our facilities for future EV and building electrification growth.

Next slide.

So we talk about the future distribution forecasting and modeling. As we looked at how we've done it historically, our existing tool certainly wasn't what we needed to really do a good job of looking into the future. So we're in a process of upgrading our load forecasting tool. And our goal is to be able to get better timing, location, and the amount of electrification, to be able to model that better, site-specific electrification for our EV growth, be able to leverage the information from CARB and DMV as far as EV data.

And just here recently, we finished up a medium- and heavy-duty impact analysis. We want to take the

results of this study, as well as others, and incorporate them into the model.

Then lastly, be able to model the DER impact that includes combined solar and battery storage.

Next slide.

So when we look at planning for electrification, it boils down to, at least for me, for three big questions. When is it going to happen? Where is it going to happen? And how much?

We need to incorporate many new elements in planning than we've had to do in the past. So we need to be able to forecast the impacts of EVs, DERs, building electrification.

We need to look at our interconnection process and make sure it's streamlined and meets the needs of our customers, and that includes interconnection of DERs, as well as also connecting new customer load to our system.

We want to make sure we have strong partnerships with our agencies so we can fast track large improvement projects.

We want to rebuild and install the new infrastructure in advance of new loads, so when we have particular areas where we're seeing strong interest along our major highways and corridors, start to be thinking about making those upgrades to our bulk system early,

knowing that this is all coming to us.

We also wanted to talk about the public outreach and educating our customers. Currently, there's a lot of misinformation that's out there that's sort of confusing for our customers. And our goal in some of our campaigns that we've started is really trying to encourage our customers to reach out to SMUD and the utility first before they dive into their plans for electrification, for purchasing a new electric vehicle, or even electrifying their electric fleet.

So then lastly, we want to also ensure that our workforce, we're developing a workforce that's ready to help us build and support the future grid.

And then lastly, I want to talk about something that's very important is managing charging and managing our loads. We've done some initial research in this area on our medium- and heavy-duty impact study. We saw just simply by modifying some of the charging times to keep them out of the peak hours, we could literally cut the impact to load as well as the cost of capital upgrades half over a 20-year study period.

So managing charging, whether it be done voluntarily through rates or even utility control is going to be very important as we move forward here in the future.

So that concludes my remarks and my presentation.

MR. WENDER: Wonderful. Thank you, Harry. And I'm going to pass it quickly to Commissioner Monahan because I've packed way too much into this agenda and haven't left enough time for discussion.

Thanks, Patty and everybody.

COMMISSIONER MONAHAN: Great. I just encourage my fellow members of the dais to hop on to the video.

And there was a lot in here. I've got to say, this was packed. I was taking notes furiously. And I want to lift up something that Simon had talked about: of the many activities that CPUC is engaged in, the freight infrastructure planning framework, which I think really is an opportunity to kind of expand. I wouldn't say we're giving up just-in-time planning, but we're really trying to be more proactive in identifying where the load is going to be and planning for that future load.

And my question, I think maybe it starts with Mark and the other folks from utilities, around just how -- you mentioned fleets in your presentation, about doing more outreach to fleets. I talk regularly to the charging providers for both light-duty and medium- and heavy-duty. And I'll just focus on the light-duty side right now because I think we're covering more on the -- I'm assuming the fleet side was more medium- and heavy-duty, but you can tell me if I got that wrong.

I'm curious about how you're thinking about planning for light-duty charging? We're seeing a lot more interest in fast charging. Charging is getting faster and faster. I mean, even with the Tesla semi, too, we're talking about a megawatt charger to be able to get to two hours of fully charged semi that would go 500 miles. So it is quite, I would say, you know, fascinating to see how the market is evolving towards faster charging, which presents some challenges, of course, for the grid, some opportunities too, depending on how we can flexibly charge.

But can you talk, Mark, Satvir, about where you're seeing -- and Matt, where you're seeing this charging, the light-duty, especially on the light-duty side? I mean, Tesla is telling us they want to double their supercharging network in the next two years. That's a lot of chargers, superchargers. So how you're thinking about planning for the light-duty load?

MS. ESGUERRA: Yeah, thank you, Commissioner Monahan. I'll start off first and then I'll definitely have the other IOUs speak out on theirs.

But for SCE, we have been doing our own engagement more individually with different charging station developers on the light-duty side. We've also been monitoring our application count. And just to give you guys some numbers, you know, I was taking a quick look over

the last two years of applications, we've had about, in terms of applications that are for interconnecting more like light-duty, about 500 kW and above, we had about 700 plus applications over the last three years, I think two to three years. And what we've noticed is we started to see kind of like, year over year, not only has the application number gone up, but we've also noticed that the size, the average size that they're coming in have slowly increased as well.

And so we've been tracking and monitoring the different EV charging station vendors, where they're proposing to put onto the grid. We've been trying to, working to engage with them to try to understand some of their longer term plans. And from that, we use that information to inform our forecast. And we're also seeing, you know, I think from the light-duty side, we are seeing those locations pop up, particularly in a couple of strategic kind of areas. But, you know, it gets intermingled with some of the areas that we're seeing from the medium to heavy-duty side.

So we're seeing some of these things pop up in areas that, largely, are around transportation corridors where we expect, you know, drives to occur where charging going to occur. So we're taking that information and building it into our forecast and then continue setting up

the engagement with these fleets.

Something that Edison is also looking at is kind of have a larger fleet operator workshop, fleet EVSE workshop, to not only share where we're looking to expand our grid, where we're thinking we're seeing the growth, but also to get their input as well.

So I'll hand it off to my other IOU colleagues.

MR. NAGRA: Great. Thanks, Mark.

With PG&E, we're doing similar things; right? We understand from light-duty EVs, the charging is along the highway corridors. That's a big, big need. We're working with the, you know, EV charging station owners, developers. We're trying to get their long-term plans. Most of them are, you know, very forthcoming and providing what they need over the longer term so that we can plan for it, include it in our forecast, and start doing proactive work, planning for that proactive work.

We're also working with the fleets, as well, similar to what Mark stated, right, trying to find out what their long-term plans are, what their load profiles look like? When are they going to be charging.

You know, one of the things I would like to mention with the light-duty, right, when we're talking about fast charging, when we're talking about DC fast charging along the highway corridors, right, those are high

demand. The loads for those applications are steadily rising; right? It's no longer 1 to 3 megawatts. It's no longer 5 to 10 megawatts. We're looking at 10 to 20 megawatts at individual stations is what we're getting.

We're also working in, you know, more urban suburban areas with DC fast chargers developers who are looking at putting in bigger stations for autonomous ride sharing and other public DC fast chargers. So those loads are increasing. We're seeing them.

We're talking to the various vendors and we're trying to get their forecast, their profiles, make sure we account for that in our annual planning. Of course, like we stated, right, it is an annual planning process and we'll continue to incorporate that into our forecast so that we can get proactive going forward.

MR. BELDEN: Yeah, for SDG&E, very similar approach. Customer engagement is key; right? That's critical because that's specific locations, specific customers and we can get together with them and plan for their long-term electrification plan. So that's the key point, one.

The other thing I would probably mention is how critical the IEPR is; right? Just in a matter of three years, right, if you look at the light-duty component and the MDHD component, they've changed significantly in a

three-year window; right? So the better information we have, the better the IOUs are able to plan and leverage that data into our process.

For SDG&E, for example, the light-duty component, our model, we are already taking vehicle registrations, TAC credits, fuel prices, historical adoption. We bring that into our model. We try to forecast where they will be adopted at a zip code level, and then the following year, we line that up with actual data to adjust our model.

So it is very granular the way we plan and try to forecast where these loads are going to materialize by a zip code level and then we disaggregate to our circuits and substations within those zip codes.

And I know you mentioned the FIP effort, which I think is fantastic. All of the IOUs are partnering in that effort. But that is going to be specifically driving the MD/HD component; right? That is going to give us more valuable information, so in next year's DPP, we have more information. We can go in and better disaggregate that component along our corridors and the areas that we are concerned. So that effort, I believe, will also help all of our methodologies in that respect.

COMMISSIONER MONAHAN: Thank you.

I want to pass it to Commissioner Reynolds.

COMMISSIONER REYNOLDS: Thank you, Commissioner Monahan. I have a question that is best addressed to the utilities.

I imagine, as you are going through the planning process and you are taking input from different project developments, different load requests, as you're working with different customers, you're generating lots of data about timelines to upgrades necessary to serve those customer loads, and talk about some of the disaggregated nature of this work, I wonder if you perform some analysis about that data and those timelines to better understand which communities in particular are facing recurring longer than typical timelines to meet new loads? Particularly, in many different areas, we evaluate programs to understand how much they are serving disadvantaged communities in the state.

Do you perform any analysis of the difference between disadvantaged communities and communities that don't qualify as disadvantaged in terms of having their distribution capacity needs met?

MR. BELDEN: So maybe I will hop in on this one, Mark.

So SDG&E, right, we -- and this is in terms of our capacity planning, the distribution planning, the context of the conversation, right, through our processes

is where we identify the grid needs; right? So if we have a customer coming to us and we have that outreach to all of our communities, tribal, local governments, cities directly, we have that outreach and that is where we gather the information on the needs of those communities and the needs of those specific customers; right? So that is where that outreach takes place.

When it comes into the distribution planning process, right, that is an input into our process. And then we apply our planning, our methodology, and that is part of that where we will then identify all the grid needs that we have in our system. And for SDG&E we treat all of our grid needs equally; right? We don't differentiate a grid need in a certain community versus a different community. We address all of those to make sure we are equally serving all of the grid needs and all of the communities within SDG&E territory.

COMMISSIONER MONAHAN: President Reynolds, I believe, has a question.

PRESIDENT REYNOLDS: Sure. Thank you, Commissioner Monahan.

So my question is for SMUD. And really appreciated hearing the description of, you know, things that you're doing to improve service to your customers, and as well you mentioned, you know, bill costs and recognizing

that the work that is done on the distribution system generally does flow into electricity rates, so flows into bills. And I appreciated the comment that you made about managed charging for electric vehicles and that that can sometimes help.

I was wondering if there's anything else to say there in terms of vehicle-to-grid integration? So are you looking at either, you know, vehicle-to-home or vehicle-to-grid powering? And do you see that as part of a solution or not? Is that something that's not helpful in terms of managing costs to -- bill costs that show up on ratepayer bills?

And then also thinking about, you know, the other, what I heard, was the emphasis on making sure that timely interconnection and energization happens for your customers.

And then I'll add on a little bit to my question, if there's time, to ask if there's any kind of, you know, external factors that would help? So you talked a little bit about things that SMUD is doing. You know, I appreciate, you know, the thoughtfulness that's going into the planning and the work on the distribution side. But any external factors, local government actions or anything else, that would help with both timeliness for energy, energization and interconnection and managing costs that

end up on customer bills?

MR. MARKS: Sure. So starting off first with vehicle-to-grid and vehicle-to-everything and then some of those, we do have some pilot projects that are underway in that space, so we're trying to learn about that and what the potentials are for there. But as I mentioned, we're open to all the technology opportunities that are out there and we'll look to pilot new stuff that's coming out and see how this could play and that is help us out, or sometimes they don't work out, so we're very open to that. And like I said, we've got some things going on that.

In regards to help from other agencies in that space there, this is, you know, easements, access, freeway crossings, normal process for permitting, and all that and all that adds into the overall process or our customers experience when they ask to connect a new load. So to the extent that we can streamline some of these permitting processes, easement process, certainly will help out with our customers in trying to make these system upgrades that we need to do.

PRESIDENT REYNOLDS: Great. Thank you.

COMMISSIONER MONAHAN: Alright, I think that's it for questions from the dais, so I'll pass it back to you, Ben.

MR. WENDER: Thanks very much, Commissioner.

COMMISSIONER MCALLISTER: I've actually got a quick question if you don't mind. Is that okay? It is okay, Ben?

COMMISSIONER MONAHAN: Oh, sorry, I didn't see your hand.

COMMISSIONER MCALLISTER: Sorry. No, I just raised it. Sorry.

I guess I'm wondering, all the utilities, just are there -- just qualitatively or with examples, how has upgrading the distribution grid changed? You know, you talked about the loads and sort of the need to really like be responsive to this coming load growth, and that's a challenge in and of itself.

But when you do upgrade a distribution line, maybe a conductor, you place poles, whatever the sort of, you know, nuts and bolts, you know, poles and wires and brick and mortar things that historically you've done, are there additional considerations, you know, controls, your status systems, say, or new controls that you sort of are also including in your plans to enable the active management of the distribution grid going forward to, you know, data collection, managing all the EV charging, sort of what other infrastructures that are sort of for the digital age are you including in your upgrades? How is that changing with time?

MS. ESGUERRA: I can start off here. That's a great question there. That's actually a big part of some of the ongoing improvements that we're looking as part of our planning process. There is going to be the ability to manage loads. You're going to have a lot of flexible load. And as was mentioned earlier, you know, the managed charging is going to help stretch out our existing infrastructure.

So what Edison is looking at as part of their Grid Modernization Plan is that we are looking at enhancing kind of a load management-type platform integrated with our DERMS and our other DER solutions, something that could, you know, take in that information from some of the third-party charging station information so that we could, you know, better -- whether it's through a signal from rates or from a program or direct control, I think that stuff still needs to be kind of worked out throughout our roadmaps, but we are factoring that into our longer term plans.

MR. NAGRA: Yeah, this is Satvir for PG&E.

Very similar; right? Everything we're building new, whether it's new circuits, whether it's new substation transformers, upgrades in substations, right, our standards going forward is to include, right, SCADA systems, making sure that all that data is going to get back to the ADMS systems we're working on and the DERM systems of the

future.

So everything we do and we build today takes automation into account because we want to make sure we have visibility into the system and we don't put, you know, any new circuits in or any new equipment in that isn't SCADA capable, that isn't SCADA, and that can't go back to the control centers where we can have active monitoring of all the data that's required on the system and then allow us to, in the future, do the load management, integrate with our DERM systems that are going to be coming. So that's just standard practice going forward.

MS. ESGUERRA: I did want to add one thing with that. We do believe that the load management is going to be a part of it, but it's not the only solution. We still see the need for significant infrastructure to be developed and deployed earlier. We do see the load management could help us bridge while that infrastructure is built, but it likely will not be able to keep up by itself because of the demands that we're seeing.

For the SCE area, we're looking at roughly over the next, for our GRC cycle, roughly an eight percent growth. We're seeing the need to develop new substations where we weren't expecting to see them, and load management will help but it's not the only solution.

I just didn't want to leave you with that, that

that's going to solve all the problems here. We still need to start the early planning to develop those solutions so that by the time we actually can build, get those things up and running, that we're not leaving customers without.

COMMISSIONER MONAHAN: I believe President Reynolds has another question.

PRESIDENT REYNOLDS: Yes. Thank you. So I have a question for the IOUs in the description of the planning work and the execution work that you're doing to match the needs of customers. So, you know, if you have a customer who has a need for either interconnection or energization, you know, my assumption is the customer really relies on the grid to be there and kind of, alright, we're ready with our project.

You described timelines from, you know, short timelines to a number of years that it might take for either grid upgrades or the work that you need to do to serve the customer. Can you describe what might go into a long timeline? So I think someone mentioned three years or so. Imagine the longest timeline for either energization or interconnection and what are some of the things that make it take so long?

MS. ESGUERRA: I can start off. Probably the largest item would be if we had to build a new substation. And you know, that's why we want to have early intel on

where we're seeing the demand growth, be able to get confidence that the load is going to be there. And some of the challenges there is finding space, getting the land to, basically, land some of the new substations. And depending on the size of the power requirements that substation may require, may require a bigger footprint. And so getting the substation sited is one, as well as now trying to identify the neighboring transmission lines or distribution lines, they're going to be piped in and those will require a different additional routing and siting, you know, crossing through various geographies.

I'd say those are probably the largest items there that really take up a lot of time is on the permitting, licensing, land acquisition phase. So those are probably maybe the largest timelines there.

MR. BELDEN: Yeah, and I would say, I would add even on a three-year window, right, for distribution. For distribution facilities, right, there's lead time. We've got permitting. We have to go through design; right? As you go through design, there's field walks. You ensure right-of-way access where you're actually going to be building if you're undergrounding or if it's overhead, the type of equipment that will be needed; right? So there's a lot of time to study, to make sure what you're building is the appropriate solution for the customer and can be

designed and constructed to meet their timeline.

So there's a lot that goes into that. And the construction and design lead time permitting is also factors into a lot of that.

MR. NAGRA: And then the last thing I'll mention, everything Mark and Matt said, but also supply chain; right? If we're building new putting in new equipment and substations, you know, breakers, transformers, those have quite a long lead time as well. So the supply chain also comes into play on there.

And then the other thing I'll leave with is right, want to make sure right, every interconnection we get doesn't require capacity upgrades or these long term upgrades; right? There's plenty of interconnections we make where we don't need to upgrade the bulk system, right, the primary system on the distribution side. So there are a lot of interconnections that are just simply that, just interconnections and they can come up to load.

But then where work is required and we have those longer timelines that we showed, you know, all these play into that, supply chain, land, permitting, being able to route transmission lines, route feeders, all of that plays into those timelines.

COMMISSIONER MONAHAN: So I know we've gone a bit over, 15 minutes over maybe, so I want to check in.

Ben, should we keep moving or --

MR. WENDER: I think let's try to push on. We'll have to do a hard stop at 1:10, so let's push to the next panel. And then Vice Chair and any other questions, hopefully, can come up.

This next panel, we'll shift the focus from the long-term planning to the immediate processes for interconnecting, energizing resources. I want to introduce Matt Coldwell, he's Program Manager at the CPUC, to give us an overview of existing rules and processes.

Matt, thanks for joining.

MR. COLDWELL: Alright. Thanks, Ben.

I guess it's still technically morning, so good morning, Commissioners, on the cusp of good afternoon here.

So next slide. I'll just jump right into it to make up some -- hopefully make up a little bit of time here.

So you saw a similar slide earlier from Simon on this point and I think it's really worth re-mentioning. And really one of my hopes, that the audience walks away today is kind of an understanding that there are these two different types of connections to the distribution system and they are quite different.

So interconnection, which we've talked quite a bit about today, is its own process and it's specific to

generation generally, but within the distribution context and the context of today's discussion, talking more about behind-the-meter generation and energy storage. And the rules that govern that at the distribution level at least are Rule 21 for CPUC jurisdictional projects, and then there's the Wholesale Distribution Access Tariff that are wholesale projects that are governed by FERC or overseen by FERC.

The other type of connection is energization. So I think we're starting to use that word a little bit more here and it's another way of saying service connection, and this is referring to customer loads. And as Simon noted, and as noted here, there are several different rules that govern energization and we'll talk a little bit more about those here shortly.

So next slide.

So interconnection, I'll focus first on the CPUC's Rule 21 interconnection. So this has a longer history. And this slide obviously illustrates it in sort of the broader electric sector historical context. And I'm not going to cover this entire timeline, but I do want to call attention to the past 15 years or so starting with the California Solar Initiative back in 2007-ish.

So really, the CSI, the Solar Initiative, really jump-started a revolution in behind-the-meter rooftop solar

projects. And when you combine that policy with innovations and financing and decreases in solar panel costs, the behind-the-meter solar market really took off and we were in a place where it was outpacing the legacy rule that governed the interconnection of those resources, which is Rule 21.

So about circa 2011, in response to this there was a Rule 21 settlement that was developed and it had the goals of -- it had several goals, but generally speaking, developing a timely more predictable and transparent distribution interconnection process. And over the past ten years or so this stakeholder process has had significant participation from stakeholders and it's been seeing some successes in establishing clear rules and schedules for these behind-the-meter resources to safely interconnect to the distribution, the utility distribution system, and I'll cover those a little bit more in detail in the next slide.

So more recently, with the second phase of the proceeding, you know, while there's been significant progress made to date, you know, this work still continues to go on on interconnection, and really, you know, focusing on Phase 2, you know, just wanted to take a second to highlight the extensive amount of work, the stakeholder work, of recent activities.

So there's been several different working groups that are focused on various elements of the interconnection process and all with kind of the general goal of streamlining the process, establishing clear processes, and enhancing the integration capacity of the utility system, as well as including establishing rules and standards for interconnecting V2G capabilities on the EV side. And so these some of these working groups have already produced results and others are still ongoing.

Next slide.

So just to highlight a couple of the successes here of a couple of the working groups.

So Working Group 1 led to a decision that really provides transparency into some of the utilities metering practices, as well as requirements for non-export relaying controls for solar plus energy storage system.

Working Groups 2 and 3, and then the V2G-specific working group, which was an offshoot for from, I think, Working Group 3, so collectively these groups have issued a decision that incorporates the integration capacity analysis into the integration process. And what that really enables is something recently that we've been working on is having the customers submit limited generation profiles for their projects. So essentially, the particular project varying through time to be able to

stay within the ICA values on a particular circuit on the utility system to avoid distribution upgrades.

Additionally, there's been some clarification around the rules that are applicable to the interconnection of EVSEs and various configurations. I'll just note that V2G for electric vehicle supply equipment can now be interconnected under the Rule 21. That's a fairly recent development. Initially, the decision provides some options for using less costly power control systems instead of relays for system that are considered to be non-export or limited export.

So next slide.

So shifting focus away from interconnection to energization. So as noted before, there are different rules for different components of energization. So Rule 15 is specific to distribution line extensions, so any new distribution lines that are needed to be built as to serve a customer. Rule 16 is specific to service extensions, so it's the equipment that's needed to connect the customer to the distribution system. Both of those are generally the costs are generally covered by ratepayers but to some extent they could be -- the customers themselves could be responsible for some of those costs, and I'll cover that in just a second.

Rule 2 is not as -- it doesn't seem to be as a

rule that applies as much as Rule 15, Rule 16 -- essentially, governs non-standard facility installs, so basically equipment that you would consider not to be your standard utility equipment needed to provide service to a new customer.

And then recently there's been specific EV infrastructure rules, Rules 29 and 45, that have been established that essentially have made all of the utility side of the meter facilities now covered by ratepayers, and I'll talk a little bit more about that in a second.

So next slide.

So this is just for the visual learners in the audience, just to highlight what I'm talking about with Rule 15. So you see with Rule 15, it's a line extension, and so that's the red distribution line.

Next slide.

And then Rule 16 is the service extension, so from the distribution system to the premise and the service panels.

Next slide.

So Rule 15 and 16, there is an allowance formula that's part of that rule that gives the project applicant an allowance against the cost. And I won't go into great detail about how that's calculated, but essentially it's first applied to the Rule 16 costs of the service

facilities, and then any excess that's available can then be applied to the Rule 15 Tariff. And you can see the current allowances for residential projects here by utility.

Next slide.

As I mentioned, there's a new EV in fact rule. This is pursuant to AB 841 from a couple of years ago. Rule 29 is the PG&E and Edison rule, and then Rule 45 is the San Diego Gas & Electric rule. Essentially, it serves as an alternative to the IOU's Rule 16 for commercial and industrial customers that does include multifamily residents and for installing separately metered or sub-metered EV charging. And essentially, the ratepayers now cover, with these rules, the ratepayers now cover nearly the full cost of service line extensions and related distribution infrastructure on the utility side of the meter. And just noting that the full cost of this policy is unknown at this time, so that's something that we're monitoring.

Next slide.

So today, it's sort of fair to say that, you know, we're at a similar place with energization that we were with interconnection some 10, 15 years ago post-CSI when we needed to revise Rule 21. So that really puts the spotlights on, the spotlight on Rule 15 and 16. And in

part, it's also due to the fact there's been several recent examples of energization delays. And not to mention that, you know, utilities, and you heard a little bit about this on the previous panel, really gearing up and planning for electrification over the next several years.

These rules haven't been revisited in quite some time and there haven't been any major revisions to this rule. I mean, the last sort of major revision was back in 2007 when some of the allowances were recalculated. So it's fair to say that there's a spotlight on these rules and that's evident by the fact that there are a few pieces of legislation circulating in legislature now that would provide guidance to the CPUC to institute some changes around energization that would definitely have an impact on Rules 15 and 16.

So next slide.

So it begs this question: So what can we learn from the Rule 21 interconnection process, the stakeholder process that we had there? What can we learn from that and apply to energization today?

And so just put a few examples here from Rule 21, the Rule 21 process that we can think about in the context of energization, you know, including, you know, looking at, leveraging the timeline reporting templates from Rule 21, looking at this interconnection notification-only approach,

which basically means if this is the pilot that's going on in interconnection right now, but if a particular project meets a certain set of criteria, it doesn't necessarily have to go through the full-on interconnection process, it could just connect to the grid. And so maybe there could be an analogous process established on the energization side.

And I mentioned this earlier, with limited generation profiles and being able to better match the generation profile of a behind-the-meter solar project with the grid capacity on sort of by time, could we do the same thing on the load side, look at customers and when are they actually using energy and compare that to when is their existing capacity on the system on a daily basis, on a seasonal basis?

And so I think there's a lot to learn from the Rule 21 process that we can apply to energization.

So next slide.

And so I'll just finish by -- just wrap up by saying, you know, the CPUC, we're actively thinking through these issues and working hard to identify some strategies and approaches to ensure timely energization of projects in the near term, but also how we can plan and prepare the electricity for new loads from electrification moving forward over the next several years. And looking forward

to working with you all on doing that, so thanks. Thank you.

MR. WENDER: Thanks so much, Matt. Really liked that analogy and what we can learn from Rule 21 for current energization challenges. Very fascinating.

I want to turn next to our colleagues at Southern California Edison. Mark Esguerra, again, will share their generation interconnection and load energization processes, with Brandon Tolentino chiming in.

Take it away, Mark.

MS. ESGUERRA: Alright. Thank you, Ben.

So maybe you go to the next slide here?

We've divided this presentation up into two areas here, very similar to what you've seen Matt cover. So we talk about our Load Energization Tariffs here, Rule 15, 16 and 29, which will largely be the bulk of our conversation. We also did include our Wholesale Distribution Access Tariff, which follows similar processes, maybe a slightly different study timeline, but the bulk of our interconnections or energizations are going to be around the Rule 15, 16, 29, and we're ready to report and talk about that.

Something to point out here is that, you know, from our forecast we're seeing -- we're projecting to see a pretty high load growth that we haven't seen in decades.

It's roughly about eight percent during these years of 2023 to 2028. And this is, you know, looking at our CEC IEPR Forecast, particularly the local reliability scenario for SCE. So a lot of load that's going to be coming in.

And on the right-hand side, after we cover our Energization Tariffs and process, we'll touch on what we're seeing on a distributed generation aspect. There's two tariffs here, Rule 21 and our Wholesale Distribution Access Tariff. As you can see here that, from Rule 21, that it's the majority of where we're seeing our generation. We have almost 7,000 megawatts of generation there. And out of that 7,000, about 99 percent of them are under the Net Energy Metering Tariff, but you can see that the average size is about 8.3 kW.

And then on the right-hand side is our Wholesale Distribution Access Tariff. Not nearly as many projects as compared to our Rule 21. You know, where Rule 21 is about 600,000, interconnections and our Wholesale Distribution Access Tariff is about a little bit under 160. And the total nameplate is about a little under 800 megawatts. So you can see kind of the larger of the volume of the two.

So with that there, we'll go to the next slide and I'll hand it off to Brandon Tolentino to cover our load energization process.

MR. TOLENTINO: Thank you. Thank you, Mark, and

good morning. My name is Brandon Tolentino and I'm the director of central design and engineering here at SCE. I want to thank the CEC Commissioners and staff for inviting us here to share our load energization process this morning.

So if we can get to the next slide?

You know, as we progress through this session, I think you'll see quite a few similarities between the IOU processes. And, you know, as we speak, I imagine you'll hear even more similarities.

At the highest level, one can simplify the processes down into really a few key steps. One is customer applies for service. The second step is really SCE or the IOU designs the line or service extension. Then we deal with requirements and dependencies. Those are typically things like inspections, easements, permitting. And then finally we schedule and we construct the project to serve the customer. So as you can see from the flow here, the process is clearly a partnership between the customer and SCE.

But furthermore, it's critical to understand that in a few of the steps, there's a dependency or a requirement that we must meet, and that's typically things like permitting and easements, so dealing with, you know, cities and counties for inspections, easements from a

variety of potential groups, permits from state and local government agencies, just to name a few.

Diving a little deeper into the steps, however, SCE has broken it down into five phases.

So first is the application phase. This is when the customer will actually contact us and provide the necessary documentation that we need to understand the project and to adequately design the necessary service to the customer. So depending on the familiarity of the customer with our process, this may take a bit of back and forth to get to what we consider a finalized submittal. And at this point, depending on the complexity of the project, we may want to meet with the customer in the field to really better understand their needs.

So once we have a completed application, we move into what we call the engineering and design phase where we create -- and this is the physical work order that our construction crews use to actually build the service online extension. And at this point, we're also working closely with our distribution planning engineers to ensure that there's capacity that exists for the new service.

In addition, SCE will also complete what we call rights checks during this time. This is really to determine if there's any easement issues that we need to address, if we need to clarify any land rights and areas

that we will be needing to install facilities. Again, there might be another field visit at this point to really aid in the best design for the customer and for the local area. In this phase, again, there could be some back and forth with the customer to align on, you know, where do they need service on their property and maybe the general routing of facilities on and near their property.

So once the design is completed, contracts are signed, the invoices are paid before the physical work in the field is started. So at this point, the customer will complete the necessary underground ducts and structure work that they're responsible for and ensure that those are inspected by the authority having jurisdiction, as well as SCE. And at this point in the process, we'll also begin obtaining any necessary permits or easements to complete the work.

Once this phase is done, we move into scheduling. And this is what I consider the actual mobilization phase where we ensure that we have permits in hand, that we have all the proper material to get the work done, and we determine at what dates we will actually have construction crews out there doing the work to provide the service.

So keep in mind, this may mean that other existing customers are affected during this time. They may see an outage so that we can complete the work safely and

securely. So there's also a notification process that we might have to go through in some of these instances where we give impacted customers, you know, a head start or a head notice on the fact that they may experience an outage due to us modifying the system in their areas. In some cases, for particularly sensitive customers or critical load customers, think about hospitals and fire stations and things like that, we may need to be more flexible in the scheduling of the outage.

Also in this phase, the customer will typically be getting their portion of the service inspected and signed off by the local authority having jurisdiction.

And then finally, we move into the construction phase where we actually complete all the work in the field. We set the meter and we energize the new service to the customer.

And then we move on to the last portion, which is really the true up and the final accounting of the project where we update all of our internal information systems, update our maps to ensure that they show the new facilities and new service to the customer.

You can see some general timelines we provided in some of these steps. You can see we also noted that in two of the phases, the application requirements phase, it can be customer dependent. Just in general, when we looked at

some averages, the customer application phase for many of the projects can be one- to two-week range. If it's, you know, a customer that may not understand the process or maybe even a more complex application, it might take a few more weeks beyond that.

And then the customer requirements phase, usually that's about a two to four week period, depending on the complexity of the project. But again, you know, if they have some issues with the ducts in structures that they install, there may be some obtaining easements, that all adds to the timeline of getting the work done.

So, you know, another, the box there also notes that we also assess the capacity on the system, so that's working with our distribution planning engineers to understand if we do need a capacity upgrade on the system somewhere, that could be a modification of an existing circuit, that could be a new circuit, a new substation, all of those things. We try to run those in parallel, but those can definitely add time to the process if we need to wait for those things to be completed.

In the next slide, I'll talk a little bit about some of the challenges and some of the opportunities that SCE is actively pursuing.

So on the left side, we really summarize some of the challenges we've seen in the process. Projects can

experience a few of these or many of these, and any will really extend the time necessary to process an application all the way through the process.

So in the application processing phase, it's really understanding, the customer understanding the information they need to submit and making sure it's clear that they have all the maps, all the requirements set, that it's clear what they actually need and that the application is deemed complete, similar to the generation process.

In the engineering phase, you know, we deal a lot with the variability of the projects. The amount of projects that happen at any one moment for us can be a challenge to our resources. The scope of the job, larger projects, of course, take longer. Some of them are challenged with permits, environmental requirements, things like that. System capacity becomes an issue in this phase as well. And then sometimes it's not clear in any of these phases like who is on point at that moment for making sure we're moving along in the process.

In the customer requirements phase, you know, any delays on their side, submitting the payment or contracts, can be an issue. You know, I talked about ducts and structures potentially being an issue of if they run into issues when they're actually doing the work. If they're unable to get their inspection completed in time, that can

be a problem.

On the scheduling side for us, you know, any storm or emergent conditions, a lot of rain, heat storms can cause some scheduling delays. More recently, we've seen a lot of supply chain challenges, not only for SCE, but the customers, as well, in terms of availability of things like wire and main panels, and on the SCE side and the utility side, things like transformers and cable could be challenging.

And then finally, you know, just site issues, just general for the customer. And, you know, if we're working offsite to upgrade things, we can see construction delays in that space.

Really wanted to end here on the areas of focus for us.

We want to look at additional personnel to help with the process, to speed up the process.

We're looking at opportunities to expand some existing tools like our DRP external portal that was used a lot for interconnection space, but can we use it for load connections as well?

We are actively looking at rolling out an online application process. We're affectionately calling it like the pizza tracker. And that's really to understand where your project is and what phase and who's responsible at

that point and what they need to provide to push things forward.

In the meantime, we're looking at how we clarify a lot of the information we provide to customers on sce.com. Can we post different and more clear process flows, any other information, can we make it easily accessible?

And then in the other spaces more recently, as we've had capacity issues, looking at how we can phase projects in. Customers don't necessarily need all the load upfront, but maybe they can phase in their load through, you know, six to nine months or even a year.

We're looking at temporary solutions to bridge issues where we may not have initial capacity but can provide some capacity to the customers.

And then I think the critical part, I think Harry mentioned previously, is really thinking about how we can speed up and make our permitting and environmental processes more streamlined.

And I'll hand it back to Mark.

MS. ESGUERRA: Thank you, Brandon.

And I think the next few slides, I know we'll go through it pretty quickly. I know we're being pressed for time here, so maybe next slide here.

So what you see on this slide is high-level

depiction of our generation interconnection processes. And as you saw in the earlier slide, for Edison, the majority of our interconnections are in our Rule 21 and they are processed through the Fast Track, which typically takes a few days, and in some worst cases, maybe a few months. And as you go further down, the studies get more complex from the independent study, the group study. Those are going to be a little bit more involved. So the focus here is really on the Fast Track.

So then maybe we'll go to the next slide here?

High-level view of the Fast Track process. Very similar to our energization, there's the upfront application processing where we've received the application from the customer, work through that with the customer, and if we have adequate information, it moves through our initial review. A lot of our projects end up just being processed from the initial review and moving right to the interconnection meeting. They've identified there really isn't many upgrades. It's things that can be handled pretty quickly.

If it's more complicated and they find there's some grid constraints, it moves over to the supplemental review for a little bit more involved study. And then after that, it gets moved over to the interconnection agreement. And if there's no upgrades needed, the customer

goes right to that five, it gets implemented. If there is an upgrade, there'd be some time to work through the project implementation for the facilities.

So maybe one more slide here, and then we'll jump to the conclusions here.

So this is just a quick view just to see, over the last several months, of what Edison's been seeing from, particularly, with the NEM 2.0. You'll see a couple of bars here. There's a blue, orange, and gray bar. Blue is 2021 volumes, the orange is last year, and then the gray is this year. As you can see, there's a huge uptick, just a tremendous amount of applications that have come in that the team is working towards over the first part of the year as the NEM 2.0 was sunsetting. And on the right-hand side, you'll see what's the average applications per month.

But, roughly, what's really important here is the cycle time. As you can see, we've been doing a pretty decent job for the last few years, keeping it under six business days. That's an average. Some are better than that. Some are worse. But as you can see in 2023, the first part of the year, those business days actually jumped up to over ten in some ways. So just wanted to give you that quick view on that.

And then the last slide here, just maybe the focus on areas of focus or the opportunities here. Things

that we're looking at here is, how do we get early engagement with the customer? Working with developers that, you know, have some expertise to help guide the customers through the interconnection process, and things that utilities are looking for is continue to enhance our interconnection tools to be able to streamline and automate as much of our processes. And then, you know, how interconnection processes are, you know, making sure that customers come in, really limit the number of changes because every time there's a change, it kind of takes us back. And then, you know, for those that require upgrades, how do you streamline the permitting and licensing process if there's infrastructure that's involved?

Went through that pretty quickly because I know that we're making up for time here. So with that, Ben, I'll hand it off to you. I do see a hand up from Diego.

MR. WENDER: Really appreciate it, Mark.

Next we'll turn to PG&E, Matt Ventura, Senior Director of Service Planning and Design, and Nadim Virani, Senior Manager for EGI.

Take it away.

MR. VENTURA: Here we go, yeah. Thank you all, and thank you, Commissioners, for having me. Again, Matt Ventura, Senior Director of Service Planning and Design at PG&E. So what I'm going to take you through here is our

new business services, so this would be the energization side of the coin here that we've been discussing today.

And so next slide, please.

So what I wanted to do is provide a kind of context of the size and scale of what we're talking about here. These are going to be in the Rule 15 and Rule 16 requests. So in a typical year for PG&E, we receive about 125,000 customer applications per year.

We structure ourselves into two tranches. So 43 percent of the applications go what we call our Express Connect or simple route. Cycle times here are under 30 days. They're real quick. They're generally focused on the work types that you can see there on the slide.

On the other 54 percent of the requests that we receive, we call them traditional or complex work types. These are ones that require specific project designs and generally take much longer with our timelines currently averaging 330 days. Let me say that this will be the area and space that has generated the most attention recently, though it is down by over about 70 days over the last couple of years as we've been putting a, you know, more intense focus in this space.

So next slide.

So the process for us is nearly identical to what you just heard. And so I won't go super deep here, but I

want to cover that this is for the complex work. This is for the process that takes, right now for PG&E, 330 days to complete. It's also the area where we see the biggest opportunity and the need for improvement within the timelines to serve our customers. As you can see in the top right corner, there are efforts already underway within PG&E to make those improvements, and we do expect our timelines to reduce by almost half.

So to go through the process steps, I just want to call out a few key items here. On intake, our first step, timelines here are mostly driven by the customer. You see zero to three months. We can go as fast as the customer can go really here. Key challenges are really generally about receiving a complete application from the applicant that contains sufficient information for us to perform our work. And that's nearly identical to what you just heard from San Diego.

Design and pricing, so the timelines here are mostly driven by the size of the PG&E queue. And so the challenges, as we've been highlighting today, can come from the capacity planning step. And so this is where the distribution planning process can significantly impact timelines that customers experience if there's not sufficient capacity to serve the customer's load request. But by and large, here are timelines when there is capacity

to serve, again, is queue-related and as part of where our improvements are focused this year.

In the dependencies space, timelines here are joint between customer and utility. It's a lot of shared responsibilities, very similar to what you also heard from the prior utility where there's permitting and land rights requirements. Those are going to be where our two main challenges come from within this space as far as timelines that are longer than anyone would like them, utility or applicant.

In the construction space, timelines here are also jointly driven by the customer and the utility. The customer does have to actually be ready and complete all of the work on their project site before we can energize them, of course.

But then let me acknowledge that really the challenges that we've been recently facing and that have driven a lot of the interest in Rule 15, Rule 16 have come from this phase for us. Most recently, quarter one of this year, we've had a historic series of storms and weather events that have really just taken these timelines to extreme levels.

So let me go to the next slide.

So what we're doing to improve, so what I wanted to show here was a representation of what the company,

PG&E, is doing. So we're in the midst of an enterprise implementation and adoption of the lean operating model. This model is built upon five basic plays and strategies, play one being visual management, play two being daily operating reviews, play three being problem solving, play four being standard work, play five being waste elimination.

So what's shown on the slide here is a representation of how these plays manifest. And as a picture of one of our walls in a dedicated wing of our Oakland headquarters, this is where we're focusing the efforts of the company to improve. And I wanted to thank Vice Chair Gunda for participating in a deep review of this content, you know, in another meeting.

But so what you're seeing here on the slide, just by making work visible, that's play one, one of our high level takeaways that we're able to highlight within the process here, as you see it there in the top right, fallout. And so what that's indicating is that 63 percent of the applications that are submitted end up not ever resulting in a completed project or an energized or pressurized, you know, customer's location.

So this is entirely applicant driven where the customer goes dark on us or they cancel their request somewhere between applying and when we energize or

pressurize them. So you can -- it should be obvious; right? So that's quite a bit of waste in our process and time spent doing things that aren't actually benefiting the grid or the customers.

Now what you can also see in the slide here is the visual evidence of problem solving or play three. It's highlighted as the pain points throughout the process with the little star stickies, so you can see both the yellow and pink. Each one of those yellow stars indicates that we've got an effort underway to address and resolve that particular pain point. And these are all really internal focusing and process optimization.

Next slide, please.

So what I wanted to end with here was just to say, so the focus of this conversation has been pretty healthy on transportation electrification. And I wanted to highlight our ongoing partnerships with these major players within the charging space. We work closely with these companies to integrate their work plans into our work plans. And we partner to resolve issues and pain points as they manifest as we've got some upcoming collaboration sessions with all of these folks.

What's not shown here, but I do want to also mention, is that we have an ongoing partnership with the California Building Industry Association, or CBIA. And

their focus primarily is on new housing, so that's also included in the content that I've just shared with you, transportation electrification and housing, both very important goals for the state and what we're trying to partner with customer groups to achieve the state's goals.

And so from there, I will go to the next slide and yield the rest of my time to Nadim.

Next slide.

MR. VIRANI: Hello, everyone. My name is Nadim Varani. I'm the Senior Manager of Electric Grid Interconnection here at PG&E.

And if we can go to the next slide, please?

So this is a general overview of what my team works on here. So we've got Rule 21, as well as the CAISO and Wholesale Distribution Tariffs, so we handle everything from your rooftop solar all the way up to your large transmission scale facilities.

Next slide, please.

So to kind of give a similar process overview that you all already kind of heard, we go from an applicant submitting their application materials. We'll take a first look at it, kind of bounce things back with the applicant to make sure that their documents are complete.

Once they're deemed complete, they move into the engineering reviews. Out of the engineering reviews, we'll

get like a scope of work, if any, that will be memorialized in an interconnection agreement, which then goes over to be designed and implemented, as Matt was just talking about.

Once all the work is completed, we move into inspection and bringing the generator online, and then moving into a Permission to Operate letter, which kind of signifies the end of the process there.

So on this screen, you have kind of different timelines for the different steps. These are from Rule 21, and so they don't necessarily reflect the cycle times of each individual step, so something like rooftop solar typically goes much faster, and then the larger facilities like wholesale distribution can take a little bit longer.

Next slide, please.

One thing we wanted to highlight, similar to the SCE presentation, was the volumes. So here you can see, going back two years to 2021 all the way through 2023, our monthly volumes by program. As you can see, there's many little colors on the side. But the main moral of that story there is in 2023, the volumes that we saw were very large.

If we can go to the next slide, please?

Something we wanted to highlight is with these large volumes, our cycle times have suffered. So you can kind of see the charts here on the right within the red box

starting to trend upwards as 2023 kind of progressed. And some of the challenges there are related to changes in tariffs, like in this case, the sunset of the Net Energy Metering 2.0 Tariff causing a rush of applications.

Other challenges to cycle time can also include technology changes from like an equipment perspective. So kind of seeing the movement from rooftop solar to now rooftop solar paired with storage devices that we have to adapt to and simplify once we understand it.

And then other challenges we face, similar to what you see on the screen in front of you is when new programs are introduced or programs change, we also have to update all of our technology and automation systems to accommodate that. So a lot of that can take a lot of thinking and designing and change management both internally and externally so everyone's on the same page about what we're looking for in applications, how to fill things out and how to get that all completed.

Next slide, please.

So with that, I conclude. And there is an appendix of slides with larger charts for those who are interested.

MR. WENDER: Really appreciate it, Nadim and Matt. Great work.

Next we'll turn to SDG&E, Erica Schimmel-Guiles,

Director of Design and Project Management, and Sherise Blackwood, Customer Generation Manager.

Take it away, Erica. Thank you.

MS. SCHIMMEL-GUILES: Good afternoon. Thank you. I'm Erica Schimmel-Guiles, Director of Design and Project Management for SDG&E. Thank you to the CEC and CPUC for inviting us to be part of the panel today. I'll be covering all of the slides. And then Sharice is here to support any questions during the Q&A.

Very similar to my colleagues at Edison and PG&E, I'll be sharing three timelines with you today, Rule 21, service orders, and work orders, in addition to actions that are already underway to improve our energization timelines and additional recommendations for improvement.

Next slide, please.

Rule 21 governs the interconnection, operating, and metering requirements for generation facilities to be connected to SDG&E's distribution system. Our Distribution Interconnection Information System, known as DIIS, was launched in 2013 and is currently recognized as a leading platform to process all of our electric Rule 21 applications. We proactively continue to make improvements to our systems and processes by working with our customers and contractors to enhance their user experience while still meeting our regulatory requirements and obligations.

The automated web application process consists of six easy steps, as you see earmarked on this slide, which identifies the responsibilities between the customer, the authority having jurisdiction, so generally the city or the county, and the utility. Ninety-nine percent of the interconnection applications we get follow this six-step process, which really helps eliminate administrative errors and improves our speed to interconnection.

We're very proud of our streamlined process. It's allowed us to achieve and maintain an average three-day approval timeline for residential applications, which is seen as best in class.

Next slide, please.

Similar to what you've seen from my colleagues that went before me, we've seen a huge uptick in applications, especially in the beginning part of this year, as a result of the Net Billing Tariff deadline of April 14th, so nearly two years worth of volume came in the first 100 days of 2023. And we are currently experiencing longer than three-day processing timelines because of this, but that is only temporary, and we will be back to our normal timelines, staying in compliance with all of the Rule 21 timeline requirements.

So with that, I'm going to move to service orders. Next slide, please.

So our service connection process for small jobs are what we call service orders, generally exclusive to Rule 16, things like providing temp power, a request for panel upgrade to support a solar install, a disconnect, reconnect, a service extension due to a remodel fall into this general bucket.

And the process begins with a customer submitting an application to us through our online builder services portal. The project is fielded. We ensure we have all proper documentation to establish what we call an applicant final submittal date, and then the service order is written.

You know, as you've heard, easements, permits, fees, all of these things are necessary and confirmed prior to the job moving to what we call our pre-construction stage. This is when the customer is responsible for performing their work, civil work, trench, conduit, any substructures, and receiving all necessary inspections.

So once all of those prerequisites are complete, the job then moves into construction where SDG&E completes the work, energizes the project, sets the meter.

The timeline for these projects is generally between three and five months, as you can see depicted on the slide. From a volume perspective, we're processing between 13,000 and 15,000 service orders annually.

And some typical challenges that we experience, again, similar to our neighbors to the north, incomplete customer applications, timely information from customers can be a challenge which delays the process, customers incorrectly installing panels or doing the trenching work incorrectly, which is not in line with the service order, and truly just the volume and some recent attrition of trained staff that we've experienced has created challenges in our timelines that we are looking to address, and I'll go into on a future slide.

Next slide, please.

So this slide is covering off on all of the other jobs, right, so think large residential development, high-rise downtown, airport expansion, commercial EV charging requests. And the process follows a similar flow but requires a lot more interdepartmental involvement because these jobs are much more complex.

So customers, again, submit their project through our builder services portal. There's generally a lot of back and forth upfront with the customer to ensure we have correct loads, plans, and all the documentation necessary to establish that final submittal date.

We then book the job to design where the engineering work is performed. So load studies, pull calcs, fielding, AutoCAD work, QAQC is done on the design,

easements are reviewed. The customer always has the ability to review the preliminary design and sign off on it before we finalize. And finalizing the design really consists of compiling environmental releases, easements, permits, pre-digitizing the work; right? All of those activities before the job moves into pre-construction.

So I will note that this slide calls out the regulatory review specifically, just to notate that some projects do require 851 or other CPUC filings, which can take somewhere between 6 and 18 weeks. But we do that process in parallel with the final design.

So again, once all the prerequisites are completed, we have permits in hand, the job will advance to preconstruction where the customer is again responsible for performing all of their work as indicated by the tariff.

Once all the final inspections are complete and the city or the county has released the job, the job will move into construction, at which time outages are scheduled if necessary, material is allocated, and the work is executed by SDG&E contractors or crews.

General timeline for this work, somewhere in the eight- to ten-month range, you're seeing on the slide here, with a majority of that timeframe really being in that engineering and design phase.

From a volume perspective on these larger more

complex jobs, we're doing between 4,000 to 5,000 projects annually. Keeping in mind each job has several potential components, right, maybe there's removing of an overhead line, providing temp power, installing new underground infrastructure, so one job may actually be eight or so mini jobs combined.

When we think about challenges with timely energization for these types of large projects, things like incomplete customer applications, customer-requested design changes after design has already commenced, permitting challenges with our local authorities having jurisdiction, land rights easements, I think one of my colleagues already mentioned that, supply chain constraints, especially in transformers right now is a challenge, and all of those things lengthen the time required to energize our customers.

Next slide, please.

So we're actively focused on ways to reduce our lead times, improve our customer experience. There's a couple areas that I will touch on.

So the first is technology. We continue to enhance our builder services portal based on direct feedback from our builders and customers. And we believe providing more information to the customers upfront really enable a more comprehensive job package submittal which

reduces the back and forth with our customers. We continue to move functions like paying online or paying rather, to, online, e-payments, signing of contracts, to online, and soon the ability to schedule inspections, as well as arrange for pre-construction meetings all handled online.

Additionally, we're rolling out a new software called Automated Utility Design, which is an application that rides on top of AutoCAD which is used extensively by our design teams. And AUD will integrate key systems, speed up our design processes and reduce errors and omissions. So we're continually looking to leverage technology to reduce our timeframes.

The second process or the second area I'll talk about is process refinement and improvement. We're continuing to look for ways to reduce handoffs, segment and align our criteria internally to help support cleaner customer interaction and processes. So an example might be one project manager assigned to all of a certain builder's projects to enable cleaner and more concise communication with that customer.

We're also looking for opportunities to programmatically outsource certain scopes of work. So an example being all removed from service, or RFS, jobs which helps us speed up getting the utility infrastructure out of the way faster so developers can secure their grading

permits and begin their work. So on average, we have about 5,000 RFS jobs per year. So if we're able to get that outsourced then our internal staff can focus on higher, more complexity work.

You know, we do believe there's an opportunity for improvement with our local agency permitting processes. I'll give you a couple of examples.

Ministerial permits, in our mind, should be simple. So the opportunity for there to be a black and white checklist where the checklist is fulfilled, the permit gets automatically approved, could greatly benefit our lead times.

Another thought is around the establishment of blanket permits with our AHJs. So SDG&E today, I believe, has about 13 blanket permits that we use, sometimes referred to as an annual permit or a durable permit, or even maybe an MOU, with various cities and agencies. And these permits allow SDG&E to self-issue permits, so sometimes there's minimal notification to the cities, and this is really for simple, repetitive, minor work. So if we're able to establish those with all the AHJs, that's another opportunity to reduce the lead time and increase the throughput.

Looks like my time is coming to an end. So I will just close with the customer engagement piece. And we

have been very intentional about engaging with the local BIA, or Building Industry Association. We hold a bimonthly working group meeting, which allows for really candid and transparent conversations around a variety of topics, whether it's legislation, supply chain challenges, process improvement, technology enablement, and that has yielded significant value and benefits.

Our executives also are holding quarterly meetings with large developers and repeat customers to, you know, air out issues of concern and strategize on partner opportunities and build trust. So we've been very purposeful about engaging with our developers and builders and establishing those open lines of communication. And we think it’s been very intentional about engaging with our developers and builders in communication and we think it's been very beneficial.

So with that, I will thank you for your time today and conclude my remarks.

MR. WENDER: Thanks, Erica. Wonderful to hear that.

Last, we'll hear from Frank Harris. He's regulatory manager of energy with the California Municipal Utilities Association.

And, Frank, anytime you'll help us make up will make me feel great and better about overscheduling. Take

it away, Frank.

MR. HARRIS: Yeah, that's great, Ben. Thanks. And I can go fairly quickly here because much of this process has already been raised and discussed.

And I think the key takeaway that I would like to leave everybody with is that I'm going to be -- I'm talking about a very, sort of the high-level process for the 40-plus community-owned utilities that I represent, but they generally follow a very similar process to what Brandon outlined for Edison and what PG&E outlined, and that is I've broken this into a three-phase process.

The first phase is the application process. This is where many of my members will have a preliminary meeting with the client and talk through the application process, what needs to be done. As was mentioned earlier, this can often involve an early site visit to help better understand and better counsel the customer. And then the customer submits that application. That application includes site plan, load calculations, panel size, things of this nature.

Once that process is complete, we move on to the design phase. And this is where the utility designer or the engineer will be assigned to the project, start and put together a basic design package. And that process typically takes about 60 to 90 days, but certain things can slow it down or speed it up a little bit. For things that

are fairly straightforward, it can usually be done more quickly. For more involved design changes or design responsibilities, that can take a little bit longer.

And then you would have this joint construction meeting. And once again, you're seeing the theme here, and that is that engagement. We've heard others talk about this. One of the key things that can make this all move faster is that routine, regular engagement between the utility and the client. And so our members tend to do these types of preliminary meetings and back and forth discussions to make sure that there's clear understanding of what is needed.

There's a review of the contracts and that process. And then at this stage, the final contract is signed. The customer submits their final payment and a lot of that administrative work is done.

And then we move on to inspection. We inspect. This is where the customer does their construction work, their trench work, any kind of pads or panel construction facilities that need to be built on the customer's end.

Once the utility inspects that, then the utility starts its construction process. And that involves, much similar to what we were talking about earlier, not just the construction but the permitting, making sure that the rights of way are all properly covered. And depending on

the equipment and the crew availability, this work in the facility takes 60 to 90 days.

`But everything that I've talked about rather briefly here presumes actually no bulk grid, no distribution grid upgrades are needed. And so this high-end, this overarching process, as I said, very similar across my members, similar to what we've already heard. I think it's important to understand where things can slow down.

We've already heard some discussions about supply chain issues. My members are having a terrible time getting transformers. And it's very typical that, particularly in a utility -- I'm sorry, at an industrial level, new service will require one or more transformers.

Depending on the magnitude of the additional load, we could see other distribution system upgrades that are needed, perhaps depending on the location, perhaps even some sort of a transmission study might be involved. I don't have something in the field my members are dealing with right now. And so where can we, how can this be sped up?

Others have mentioned this, I mentioned it just now, that open and continuing bilateral communication between the utility and the customer is key. What we find is that if we have a very clear plan from the customer,

including their load calculations, their site construction is all very clear and straightforward, these things move a lot faster.

When we talk about electrification, fleet electrification versus light-duty electrification are showing up to be two completely different things. And many of our members are getting calls to do fleet electrification upgrades, but customers aren't quite sure what these trucks will need yet. And so they aren't able to come to us with sufficiently specific load calculations or timelines when the vehicles will be available and purchased. And so that type of uncertainty slows down this process.

We've already mentioned supply chain.

And then, of course, staffing and other equipment needs. I can't remember, I think it was Brandon at Edison, but maybe it was Mark at Edison who mentioned that supply chain hits both sides of this. The customers have trouble with certain equipment that they need, wiring and other equipment. We have a challenge getting some cabling and getting transformers, other equipment. And then, the staffing needs are always a challenge.

But nonetheless, if I were to leave you with that one thought, this process is fairly consistent across utilities. I think sometimes customers are concerned that

it's sort of a Wild West out there, but the general processes follow very similar patterns as what we see with the IOUs and what we've talked about today. And so just earlier notification, more communication between the client and the utility can help speed this up.

I'm going to give you back, hopefully I didn't take too much time there, Ben, but I'm going to give it right back to you, buddy.

MR. WENDER: Thanks so much, Frank. I owe you for making up a little bit of time.

I'm going to invite our esteemed Commissioners to climb onto the dais and take us off with questions until about maybe 1:10, 1:12, if we're lucky.

VICE CHAIR GUNDA: Thank you, Ben.

Commissioner Monahan, I'll just jump in here.

So first of all, I just want to say, Matt, thank you for bringing the visual of the whiteboard and the tracking. That was a really wonderful time well spent with you and understanding all the processes.

So I have a multitude of questions here, but I'll kind of keep it to something that was analogous to what we've seen on the transmission side with the cluster process; right? We've seen this humongous amount of applications for new generation interconnections. And it was very evident on the Rule 21 interconnections on the NEM

side and storage side. So a couple of questions on that.

One, how many projects, for example, in those interconnection requests you have actually go from start to end? Do projects drop off or is it like pretty much like 90 percent or higher or 70 percent or higher? That's the first one.

And then the second, moving forward, you know, I think there has been some information that was shared, you know, in workshops and such about, you know, there was a surge in applications with the NEM given the kind of the tariff change to NEM 3 and, you know, a lot of desire to stay in NEM 2. Could you kind of just lay out how you see the process in the past, how much went from start to end, what portion fell off? And then moving forward, the extraordinary amount of applications that you have to deal with, do you think that those actually manifest into projects in the near term or over a period of time here?

MS. ESQUERRA: Vice Chair Gunda, this is Mark from SCE. I could speak a little bit on the Rule 21 aspect of it.

So the majority of like the large volume that we're seeing, largely most of those systems, the customers have already been in -- has an arrangement with their installer. They've largely kind of partially installed or almost installed. So we see, basically, a high volume of

those actually turning to those are actually real projects.

So I think where there's probably going to be some areas where maybe the projects could drop out would be on our wholesale side and maybe some of our larger interconnections, but a good portion of what we're seeing on the generation side, the rooftop solar, those are actual projects and they move forward.

MR. VIRANI: If I may add? This is Nadim from PG&E.

Traditionally, the NEM systems almost always make it from start to finish. As Mark said, wholesale has much higher dropout rate, like more than half, bordering up worse than maybe 80, 90 percent dropout. Right around the time they find out the costs of the interconnection, they do their business case.

With the latest kind of surge of applications on the NEM side, we suspect that most will go forward, but we do expect a higher than normal dropout rate. Anecdotally, I don't have firm numbers yet, but it looks like almost a third or half of them are very speculative without a lot of application materials having been submitted. So we're kind of evaluating, you know, how that's going to impact our cycle times as we go back and forth with customers to try to figure things out.

And as folks are probably aware, they do have

three years to build that system. So we suspect a lot of these applications are kind of brought forward from like the rest of '23, maybe early '24, just to make that NEM 2 sunset.

VICE CHAIR GUNDA: And because I'm just kind of thinking through, you know, it has direct implications to the forecasting where we use some of the application data into kind of thinking through the demand, so great.

And just if I may, Commissioner Monahan, just one quick question on the resources?

I think we've talked about resources. So kind of a lot, and broad question here: Is the issue finding the people with the skillset or is it just that the resources at the utilities and are not being spent to resource up, or is it a combination? If you could just kind of explain that?

MR. VENTURA: Alright, I'll take the first crack at that. Thanks, Vice Chair Gunda. So Matt, PG&E.

Resources, so I'm talking around Rule 15, Rule 16 requests, so if that's what you were asking about, so we have, let's say, our design resources, which we are trying to staff up and we have been for some time. Those are a more skilled workforce that takes time to gain the necessary experience to be able to do it well and to do it quickly. So we're in a phase of staffing in that space.

In the construction space, we don't think that there's, let's say, a mass resource issue there. There's plenty of contract support versus PG&E internal labor support within the construction industry. And so not really seeing challenges there as far as a barrier to executing the work.

MS. SCHIMMEL-GUILES: I'll just echo Matt's comments. At San Diego, we're seeing the same, generally fairly flush with, I think, the construction resources necessary to get the work done.

The design and planning resources generally take two to three years to get fully capable in the work because of the complexity of the processes, the tariffs, the interpretation, the application, just the variety of experiences and situations that the planners and designers are going to come across in the field.

So it's really a matter of finding talent, you know, retaining them, training them, up-skilling them, and getting them fully-fledged, ready to execute work quickly. And that's been a challenge over the last few years.

VICE CHAIR GUNDA: Thank you so much. There's just so much information here. Thank you so much, all. That was wonderful.

COMMISSIONER MONAHAN: So I'm wondering, I also, Matt, got a chance based on Vice Chair Gunda's

recommendation, actually, Ben Wender and I went and saw the whole flowchart and was really impressed that this was a really like inspirational project to kind of air, I don't want to say air your dirty laundry but, you know, really be very transparent about, well, this is a holdup, this is when it's our fault, this is when it's the customer's fault.

And one of the things I found is everybody finger points. It's like if I talk to a charging company, they say, it's the utility. If I talk to the utility, they say, it's the charging company or it's a local permit.

And I'm wondering, and maybe this stuff feels kin of the portal that you talked about, but is there any suggestions for how we can make things more transparent so you can actually say, here's the data, kind of like PG&E and is doing but on a more like public way? Because otherwise, everybody's just always blaming each other a because we don't know.

MS. SCHIMMEL-GUILES: I can take the first shot at that, Commissioner.

I think part of the challenge and one of the conversations we're starting to have at San Diego is how do we get really far out in front of our customers instead of waiting for them to come to us? Because at this point, based on the volume and the timelines that it's taking us

to get the work done, we're already behind their expectations when they come asking for the work; right?

We need to get better at forecasting and taking data relative to where we've seen the load growth happen. What do we anticipate our customers doing? What are the Teslas, the Electrify Americas, the big EV installers doing two, three, five years out; right? And aggregating that information and taking it into our planning functions so that we can get out ahead of the work, especially with the capacity and the potential backbone needs that are going to be necessary to facilitate the state's goals of decarbonization, electrification, transportation.

There's also got to be a conversation around like what is that mechanism to allow us to go proactively do this installation and infrastructure upgrades in advance of those customers actually coming to us? I think the GRC is a little too rigid and doesn't really allow for us to be really responsive and also proactive in nature. And so, you know, conversations around what does that funding mechanism look like? How do we set up a structure to help our customers be successful where we're leading them because we're already out in front?

MR. VENTURA: I'd add that, as I listened to the presentations from all of the utilities here, so I think that the way we bucketize and categorize our work is we all

follow a very similar process, but the amount of scope that is included within each customer project, it definitely differs. And so whether it's only a Rule 16 project or it's a combined Rule 15, Rule 16, or it includes some portion of a backbone or a capacity, you know, betterment piece of work.

And so where are the delays that you're hearing, Commissioner Monahan, I think it differs depending on what the types of projects are. So I would suggest that it's important to get the scoping clear so we're talking apples and apples because it's -- let's just say if you're talking with a charging vendor, they're going to generally, let's say like if they're dealing with PG&E, they're going to have concerns and issues with the capacity and the distribution planning process. That's where a lot of their concerns come from and it is really to the utilities responsibility there; correct?

But if you're talking, let's say someone that's doing just a Rule 16 project, well, then I would imagine my colleagues here would suggest that the customer having the right application information, being responsive and working and communicating with us, as Frank was suggesting, like that's where that becomes an issue and it's more on the customer side of the fence there.

So it really sort of depends on what is actually

trying to be accomplished and that's where you can get a good sense of what's going on for delays.

COMMISSIONER MONAHAN: Well, we have to cut it off, we had a hard stop at 1:00, but this has been a great panel and I wish we had another half hour because I have more questions, but thank you so much.

And I don't know if, Ben or Heather -- oh, do you want to be one -- okay. Thanks Heather.

MS. RAITT: Hi. Yeah, so I just want to say thank you to everybody and that we're going to close this out, but we'll be back at 1:45. So I just request everybody log back in just the way you logged in for this morning. Apologies for any inconvenience with that but hope to have everybody back here at 1:45. Thanks.

(Off the record at 1:10 p.m.)

(On the record at 1:47 p.m.)

MS. RAITT: Great. Thank you for coming back. Welcome back to the workshop on the Clean Energy Interconnection with the Distribution Grid. I'm Heather Raitt, the Director for the Integrated Energy Policy Report, or the IEPR.

Just a reminder that this workshop is being recorded, and we'll link a recording and a transcript to the Energy Commission's website.

And also just a reminder that, because we do have

such a full agenda today, we don't have time to be taking questions from attendees, but we do welcome comments during the public comment period during the end of the day, toward the end of the day. And again, we won't take questions during that public comment period, but we welcome your comments. And if you'd like to comment, go ahead and press the raise hand function on Zoom.

And then we also welcome written comments and those are due on May 23rd. And the notice gives you all the instructions for doing that.

So with that, I'll turn it over to Commissioner Patty Monahan.

Thank you.

COMMISSIONER MONAHAN: Thanks, Heather.

I'm going to be really brief because we ran over in the last section. I think that's why some of our CPUC colleagues are not on. Oh, and they're showing up. I see Commissioner Reynolds, and President Reynolds was here earlier, as was Commissioner Houck. So I'm expecting for, potentially, Commissioner Shiroma to come in the afternoon.

And I want to make sure we have time for the panels and for discussion where, I think, the heart of the matter is. We're very excited for the afternoon session of this workshop, really focused on speeding the interconnection and deployment of clean energy resources on

the grid. And we're looking at the small wires part, the distribution side, and really looking for ideas for how we can speed up the connecting of buildings and transportation and solar integration into the grid so that we can help meet our state goals.

So I'm going to just pass that quickly to Vice Chair Gunda to see if he has any remarks. And he's shaking his head no.

Commissioner McAllister, Commissioner Reynolds, anybody want to -- okay, let's dive in.

I'm going to pass it back to Ben Wender, my advisor, who's been our leader through this process.

MR. WENDER: Thanks so much, Patty, and great to see everybody.

This morning, we heard a lot about existing processes, planning processes, processes, connection processes from the state agency and utility perspective.

Now we want to turn and learn a little bit about the experience from the developer side. I want to introduce Cliff Rechtschaffen, former Commissioner of the California Public Utilities Commission, who is gracious enough to moderate this afternoon's panel.

Cliff, take it away.

MR. RECHTSCHAFFEN: Thank you very much, Ben. Thank you for having me. It's always a pleasure to be at

an IEPR workshop. I couldn't think of anything else I'd rather be doing.

I was asked to spend a few minutes setting the stage for this panel. I think it's been very well set by all the panelists in discussion this morning, starting with Chris Walker of GRID Alternatives talking about, and others, about the historic opportunity we have right now. We have alignment on policy on very ambitious clean energy goals for transportation electrification. Otherwise, the market is ready. Twenty-one percent of all new vehicles in California are ZEVs, this first quarter, the most ever. We have a huge demand for rooftop solar and batteries, as you heard this morning. We're going to be connecting tens of thousands of electrical appliances over the next few years.

We're also in the midst of a serious housing crisis. There's great demand for new housing. And as you'll hear from on this panel, developers are being told they have to wait months if not years to get power delivered to them.

So in this area as in so many others, California has to lead the way in not just devising its climate policies but implementing them, making them happen. And that's a very difficult challenge.

We heard from the prior panels, some of the difficulties and the complexities. Some projects are easy,

some are more difficult. There are multiple steps, some within the control of the IOUs, some within the control of parties like we're going to hear from on this panel, some third parties, local governments, landowners. We need to make sure that whatever connection is done is done safely. We heard about supply shortages, shortages in some skilled work forces.

We have a huge challenge with rapidly evolving forecasts about what load we're going to have and when it's going to show up and where. And we didn't hear so much this morning, but it's, of course, in the forefront of many people's minds that the utilities have a lot of other things on their plate. The state's being asked -- asking utilities to do a lot to ensure safety against wildfire risk, to modernize and make safe aging infrastructure and so forth.

A lot's happening. We heard quite a bit from the utilities about what they're doing. And if we have time, we can, to the extent that any of our panelists were listening in, we can get reaction to that. A lot's happening at the agencies, both public, the PUC, and at SMUD and others in the distribution and planning area.

A very exciting, I want to put a plug out to the very exciting Freight Infrastructure Plan that the PUC is going to be unveiling May 22nd, which is a proactive plan

to better match long lead-time resources needed for heavy- and medium-duty fleets with where they have to be on the grid, so that's a really important effort.

And one other shout out, too, that wasn't talked about earlier, the PUC, last year, adopted a resolution setting average timelines for the energizations of electric vehicle projects, an average of 125 days for actions that are under the control of the utility, so that's four months in. It may be worth discussing how that's worked so far. There are other requirements for gathering data about how that's working, identifying obstacles to meeting those deadlines and so forth.

There's also an appetite in the legislature to step in. And I think you'll hear more about that from Corey in his presentation. The legislature is very focused on how to make sure that connections happen more quickly and looking at tools to make that happen.

So with that, I think my last point, it's very clear that we will need solutions from all the parties involved in these connection processes, both the interconnection and the energization process. So it's great to have a panel of experts on the small wire side from the developer perspective.

So we have four panelists talking about their experiences and we asked them to particularly focus on

solution, pragmatic solutions, real life solutions, best practices so that they can make their way into the IEPR recommendations, which is a goal for many people in life to have their stuff in an IEPR recommendation.

So the first panelist is going to be Francesca Wahl from Tesla. Francesca is the Senior Policy Manager for Public Policy and Business Development and she leads Tesla's North American policy and implementation on EV charging.

Francesca, the floor is yours.

MS. WAHL: Great. Thanks so much, Commissioners, for having Tesla today on this panel.

I will be speaking from the perspective of an EV charging developer and mainly related to our supercharger projects, which is our direct current fast charging. But certainly some of the information that I will provide can apply to Level 2 or AC charging, as well as all the way to the medium- and heavy-duty scale that we heard about in some of the earlier presentations as well.

This particular slide is just the development process in very high level buckets from an EV charging developer perspective from the day that we start thinking about a site, all the way until it's open to the public. When we develop fast charging in California, we're looking both at highway corridor fast charging, so route

enablement, as well as urban fast charging. So two different use cases and applications, but both very important to meeting EV demand across the state.

Next slide.

And then just to contextualize a bit of Tesla's scale and footprint on the fast charging side, this is just a graph showing how many stations we have in each of the major IOU and unique territories across the state. Today we have over 370 fast charging locations with over 5,200 fast chargers. We're looking to more than double that by the end of 2024, so a bunch of more charging to come in the next two years.

Our average site size in California is anywhere from 12 to 20 fast charging stalls, but we have projects ranging all the way up to our biggest one in the world, which is in California, which is 98 fast charging stalls. So we're definitely talking about bigger scale as we continue to build out, especially highway corridor fast charging sites, to help support our customers.

Next slide.

This is just a quick snapshot of what we're seeing today and historically on our project timelines for superchargers in California. This is all in, so the proxy that we're using here is leased signs to open to the public. And the median here is really around 300 days for

both the IOUs and the municipal utilities across the state, but certainly there are projects that move much slower and much faster than that.

And one important thing to note here is that, you know, Tesla as an entity is just as much as responsible for this timeline all in as the utility. And so for this particular case, it's actually a 50-50 spread in terms of time. And so we're really looking to work with our utility partners to bring down the timelines on both ends. And, you know, in looking at the PUC's energization timeline targets of 125 business days, if we split this in half here, you know, we're seeing roughly 150 days. So I think we still have some work to do, but we're getting closer on being able to meet those targets for the projects that are actually participating in Rules 29 and 45 where they apply.

Next slide.

So what are some of the timeline challenges? I think this will be similar to what you've heard from some of the other presenters, especially the utilities earlier on. We're seeing transformer shortages. We're seeing disruption to construction scheduling. We're seeing right-of-way permitting issues and needing to be able to streamline that process. And we're seeing capacity upgrades. And, you know, the delays really can range, with capacity upgrades obviously being the longest timeline if a

substation or other distribution system upgrade as needed. That can add, on average, two years to a project timeline, which is really challenging. And so that's an area we're definitely trying to figure out how to proactively address that.

And then some possible solutions, I won't get into this too much now, but happy to speak more to that during the Q&A.

Next slide.

And then we did want to just show the cost differential that we are seeing from a development perspective, and this is really to highlight how, you know, Rules 15, 16, 29 and 45, which have varying degrees to allowances that are being covered for the customer, really are making an impact from a cost perspective. And so you tend to see a bit more development in the IOU territory, given that on average we are seeing lower costs with those new rules that cover more of the infrastructure costs being applied.

Next slide.

And then finally, speaking a bit to the policy problem of capacity for fast charging, I recognize this slide says T&D upgrades, and we're really talking about the distribution grid side here, but generally the same concepts can apply in the discussion.

The graphic that's up on the screen on the left is from a recent study in the Northeast that National Grid, CALSTART, and the Rocky Mountain Institute, and some other partners did trying to look at the needs for highway corridor fast charging in New York and Massachusetts. If you haven't had a chance to look at that, take a look. It's an interesting way of just kind of thinking about what we're talking about from a capacity perspective, not just for light-duty, but also medium and heavy-duty charging applications.

And I think as you've heard before, it's really, you know, that delay of two-plus years, that can cause -- have an extreme impact. We're moving quickly, we're trying to scale, and that can really slow us down. And we're already behind in meeting even deployment goals with customer needs for charging access. So this is a critical issue that we need to address and work together.

Next slide.

So thinking about different solutions, there are a lot of different ways to tackle this. And to some extent, some of this is already happening, especially with some of the forecasting updates that are happening as part of the Demand Analysis Working Group in the IEPR process.

But generally, we still feel that, you know, a multi-stakeholder process dedicated to looking at this

capacity issue, especially in the context of highway corridor fast charging, whether that's for light, medium, or heavy-duty, is important. So, potentially, there's an opportunity to build off of, you know, a framework like the California Ready Initiative amongst the agencies. That's not necessarily in a regulatory process, but more as part of a work group.

Opportunity to expand capacity in key areas. While we can't always site fast charging where capacity is available, since we're looking for other things like amenities, available land, there is opportunity for developers to look at that, so working with developers to more proactively determine where there is capacity today, and then how long it will take to get capacity there.

Ideas like looking at funding to, you know, help support additional buildout, reducing any risk on ratepayers.

And then again, looking at sort of this idea of travel corridors being identified as kind of charging zones and figuring out ways to work with the developers to bring forward investments in those areas.

I'll pause there. I'm happy to take questions and look forward to the discussion.

MR. RECHTSCHAFFEN: Thank you very much. I'm sure there'll be questions.

Our next speaker is Rachel McMahon. Rachel is very bravely, heroically doing this without slides. She is a principal at Grid Power Consulting, but here representing the California Energy Storage Alliance. Rachel has a long history of working in the clean energy space at the California Public Utilities Commission and other clean energy organizations, most recently with Sunrun.

Rachel.

MS. MCMAHON: Thanks very much. And I'm going to struggle to not call you Commissioner.

So good afternoon. My name is Rachel McMahon with Grid Power Consulting, and I'm here today on behalf of the California Energy Storage Alliance. Many thanks to the Energy Commission for holding this workshop.

My comments and recommendations focus on the Rule 21 process as it relates to stationary energy storage. And I will touch on several points.

So one, the first, we've heard a lot about today, so interconnection timelines, as well as cost sharing, installation of electrification technologies, and then also grid services.

In opening, I'll say overall, Rule 21 is a model rule in many aspects, but it really does need to evolve to meet the changing needs of the grid and the electricity system.

So starting with timelines and cost sharing, the Rule 21 process has been very effective in interconnecting small and solar only net metered systems. The adherence to timelines is mixed for larger systems and NEM systems paired with energy storage, as well as non-solar and more complex distributed energy resource systems, including storage and microgrids. This reality was clearly reflected in an analysis produced by Guidehouse Consulting in 2021 for the Public Utilities Commission that examined Rule 21 interconnection timelines across the three investor owned utilities. And we've also heard a lot of really productive and interesting discussion on these topics today.

So some steps are, of course, underway to expedite interconnection for non-NEM resource types. So as the investor-owned utilities explained in great detail in the prior panel, they're designing new processes to resolve issues with timelines, which is great and appreciated.

There's also a pilot under development at the Public Utilities Commission called the Notification-Only Pilot that will allow small non-exporting storage systems to interconnect on an expedited basis. It is a step in the right direction, and this process could and should be updated over time with both allowing for larger as well as exporting systems.

And currently, exporting non-NEM distributed

energy resources bear the responsibility for upgrades to the utility distribution system that are determined to be caused by our projects, as we all know. And this responsibility sinks a number of projects as the cost can overwhelm the project and make it no longer cost effective to install.

In other fora, CESA has proposed distribution cost sharing for exporting DERs. A cost sharing approach would more appropriately allocate the responsibility for distribution system upgrades between utilities and DERs. The premise of this approach is that the utility bear the cost of the in-kind replacement scheduled upgrades or other normal upgrades to their distribution systems. And participating distributed energy resources would pay pro rata shares of the costs of the incremental DER related upgrades that are specifically assigned to their projects. So there are similar processes on the transmission side that have been around for quite some time. Something similar does not exist on the distribution side.

Moving on to electrification. And so a few of the Commissioners actually touched on this today. And when I say electrification, this refers to any type of electrification, whether that be home electrification or onsite EV charging or simply pairing storage with a customer's onsite solar system.

Any of these additions typically require upgrades to the main panel in homes and businesses. And currently, utilities require utility employed electricians to be present when performing the disconnect and reconnect of the customer's main panel. And the result is that oftentimes customers have to wait months sometimes to interconnect a system, which is a horrible customer service experience.

And this problem is only exacerbated in the near term by the recent massive volume of interconnection requests from customers that wish to operate systems under the second iteration of the state's net metering regime. The spike in applications was discussed in details by the representatives from the three investor owned utilities.

And importantly, the need for main panel upgrades will increase in the future as the solar industry finds its footing under the Net Billing Tariff, which effectively changes the state's customer-sited solar market to a solar and storage market going forward. And as David Erne highlighted at the start of this workshop, interconnections for customer-sited solar storage and EV charging will hockey stick in the next 10 to 15 years, so this is a problem that must be addressed.

So I have one recommendation here. In a few instances, utility field offices have let qualified electricians, on the behalf of third parties, do the

disconnects and reconnects, or so-called hot work. But this is not consistent among the utilities nor is it really widespread at all. It's just really a few instances.

Allowing qualified electricians employed by third parties to perform this work will support operationalizing and energizing these technologies far more rapidly. And this is a simple and actionable solution that can happen in the short term. It does not require a decision from any agency nor a multi-stakeholder process. So this is just specifically utility processes and preferences.

Finally grid services. So I'll start with non-export requirements. So storage-only and generally non-NEM systems typically have non-export provisions in their Rule 21 interconnection agreements. This does not always result in the most optimal use or design of these assets. So first, this load-limited model in some cases results in undersizing the energy storage system. And second, this design hampers the ability for behind-the-meter energy storage to provide exports under emergency reliability programs.

Increasingly, our leadership in California is relying upon distributed energy and load resources to dispatch in emergency grid conditions. Systems with a non-export relay cannot provide energy-only exports to programs like the Emergency Load Reduction Program designed by the Public

Utilities Commission, nor capacity exports under the Energy Commission's proposed revisions to its Demand Side Grid Support Program. This is contrary to the best interest of the grid and ratepayers and clearly evolving state policy.

And finally, Rule 21 interconnected DERs may not participate in the wholesale market as exporting. Instead, these resources must pursue an entirely separate interconnection process called the Wholesale Distribution Access Tariff, which is jurisdictional to neither the state of California nor the CAISO itself. This is one of the key barriers to wholesale market participation by these resources. And I'm not aware of any practical physical reason why this dual process must continue to exist.

Instead, Rule 21 should be modified to allow exporting DERs to participate in the wholesale market maybe with some additional studies and process rather than requiring a separate process.

So thank you and I look forward to the discussion.

MR. RECHTSCHAFFEN: Thank you, Rachel. Thank you for being so concrete with those recommendations.

So our next speaker actually is subbing for our JT Steemkamp. I'd like to welcome Henrik Holland, who is the Global Head of Electric Vehicle Charging at Prologis. Henrik previously was the Chief Operating Officer at Shell

Greenlots.

Please go ahead, Henrik.

MR. HOLLAND: Thank you so much. And thank you so much for having us here at this session today.

For those of you who are not familiar with our company, Prologis is the world's leader in logistics real estate, meaning that we build and operate logistics facilities globally. With assets totaling over 1.2 billion square feet, approximately 2.8 percent of global GDP flows through our almost 6,000 properties each year. This includes essential goods Californians need to live their daily lives.

We were founded and have our headquarters in San Francisco. And while we operate in 19 countries, California is our largest market, where our portfolio includes over 200 million square feet of space across nearly a thousand properties.

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Prologis has committed to reaching net-zero emissions for our entire value chain, so that includes Scope 1, 2, and 3 emissions by 2040. To support this commitment, we've set a goal of deploying 1,000 megawatts of solar storage and EV charging capacity across our global properties by 2025.

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To help us meet our net-zero goals, our energy business is expanding solar generation and battery storage at our properties, and our mobility business is installing EV charging infrastructure for fleets.

In 2022, Prologis was ranked the number two in corporate onsite solar. Prologis is leveraging our rooftop solar potential, which will support the state's goal of reaching 100 percent of zero-carbon electricity sales by 2045.

Now our customers look for our help as they electrify their medium- and heavy-duty trucking fleets across last-mile, drayage, and other applications. Our mobility business is developing truck charging infrastructure at warehouses and at dedicated charging hubs. We have already publicly announced two of the very first heavy-duty trucking installations in California with many more in development.

Now I don't have to tell you that the rest of the nation is watching California's transition to zero emissions. But our success depends on fast decision making, new ways of working, and strong public private partnerships. From our perspective, the California Energy Commission can assist in these efforts by addressing the following five challenges.

First, streamline the service connection process

for EV load electrification. A significant barrier for the deployment of electric fleets is the speed of securing service connections. These connections can take years for large installations, which is very common in the energy intensive commercial EV fleet segment. This will stand in the way of achieving the ambitious electrification goals that state and local governments have set, including our customers.

The private sector can't address this issue alone, so we're asking the CEC to evaluate how utilities and public agencies can streamline and prioritize service connections for fleet electrification. Solutions may include upfront commitment from project developers, site control, load justification and guarantees, which should reduce the logjam from speculative projects, making it faster to develop committed projects.

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Second, remove the limitations on companies to self-generate power for commercial EV fleets. To address the challenge of the long service connection timelines that I mentioned, Prologis has developed zero and near-zero emissions electricity generation solutions that could provide temporary power first, and then backup power to provide grid resiliency services once utility services are in place. However, these solutions are not always possible

and depend on utility policies.

Given the demand on the grid and interconnection queues, we need to find ways to allow industrial customers more options to self-solve with these types of temporary power assets, which can then transition to support grid resiliency once an interconnection has been established.

Third, reform the interconnection process for distributed front-of-the-meter projects. The current interconnection process for front-of-the-meter projects isn't well-suited for distributed scale projects for 5 megawatts or less. All front-of-the-meter projects currently require medium voltage interconnection via a Wholesale Distribution Access Tariff, which is both expensive and unnecessary for this size of project.

There are also constraints on the Wholesale Distribution Access Tariff, or WDAT, Fast Track process for smaller systems, which include batteries that unnecessarily limit how the batteries are sized and used. The WDAT Fast Track process doesn't currently allow for allocation of deliverability. The CAISO only assigns deliverability for projects including distributed scale projects through the cluster study process, which means that distributed scale projects that can come online technically in a one- to two-year timeframe must wait for three years or longer to be granted deliverability.

These interconnection challenges are inhibiting the development of distributed scale front-of-the-meter projects. And given the urgent need for new reliable capacity in California and the ability for distributed storage resources to be deployed on an expedient timeline, it is critical that the state develop a dedicated interconnection process which includes deliverability study for distributed scale resources.

Fourth, support CAISO's and investor-owned utilities' efforts to improve the cluster study process. Prologis submitted a number of interconnection applications for the development of new renewable energy projects in the Cluster 15 process, and we support the effort to implement structural reform for this process that encourages applicants to demonstrate achievement of development milestones including site control. This will focus the study efforts on projects that are being pursued by serious developers and have a high probability of success.

Finally, promote opportunities for rooftop solar deployment, including supporting a broad community solar program across California, as other states have done, like New York and Illinois.

In closing, Prologis is keenly focused on helping logistics businesses in California transition to clean energy. However, the private sector cannot deliver the

charging and clean energy infrastructure needed to meet the state's ambitious goals without a strong partnership with utilities, state energy regulators, and local and state elected officials. We think that part of that partnership is governments and public agencies setting aside traditional approaches to meeting power needs of our communities, customers, and businesses. Working together, we can lead and show once again that where California goes, so goes the nation.

Thank you very much.

MR. RECHTSCHAFFEN: Can I ask you a quick follow-up question? Those two charging depots you mentioned, those two charging depos you mentioned right at the start of your presentation, where are they located?

MR. HOLLAND: They're in Southern California, Santa Fe Springs and the City of Commerce respectively.

MR. RECHTSCHAFFEN: Okay. And who's the electric utility in those?

MR. HOLLAND: These are both Southern California Edison Territory projects.

MR. RECHTSCHAFFEN: Okay. Great. Okay, well, thank you very much, Henrik.

Our last speaker is Corey Smith, who is the Executive Director of the Housing Action Coalition, a nonprofit that advocates for building more homes at all

levels of affordability across the Bay Area. And I bet Corey never dreamed that he would be immersed in energy, wonky energy division policy when he took this job, but here he is.

Go ahead, Corey.

MR. SMITH: You're not kidding. I've learned more about this in the last couple of years than I had ever anticipated. And it's relevant to the home building challenge. So thank you, Cliff, for having me. And good afternoon, everybody. Corey Smith, Housing Action Coalition.

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Just to give you kind of a little bit of quick context as to who we are and how we sort of play into this: so as mentioned, we do housing advocacy at all income levels, meaning we want to see supportive homeless housing, subsidized affordable housing and market rate housing get built faster across all of California. We do primarily work in the nine-county Bay Area, and then in Los Angeles and Orange County as well. And we are a member funded organization, so people that build housing, but we also work in between both government entities, and in this situation, the investor-owned utilities and municipal utilities, as well as the general public. So we try to be a connector of stakeholders in a certain sense.

And next slide.

Over the last couple of years, we heard continued complaints, quite frankly, from our members related to the permitting process. And upon diving into that, I've had now a couple of people tell me that quite literally every single project that they are doing faces some sort of delay at some point in the process. And oftentimes, quite frankly, this is just because of the poor system that we have set up between project applicants, a municipality, city and county and a utility company, regardless if they are a municipal utility or an investor owned utility.

And it is, again, kind of start to finish, to be perfectly honest, from the initial preparation of plans, I mean, before applications even come in during the review process. The idea of disconnecting and temporary power got mentioned, some of that hot work or dirt work, another kind of way to put it. And then at the very end, we heard continuous complaints about this final interconnection. And as, basically, our members have put it, we've got a building that's completely done and people are ready to move in, but just getting it connected to the grid is taking longer than expected.

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So there's a variety of reasons that this is the case. I'm actually not going to touch too much on this,

because I think it's been probably hammered home throughout the day.

Two things I do really want to hammer home, though, that we have heard, number one, this concept of fee for service and that this is something that project applicants and our members are paying to get done. So it's not kind of part of the essential infrastructure work where, in our case, you know, developers, affordable housing developers or market rate developers are paying to get this final interconnection done so people can move in. And that's not happening in a timely fashion.

And while it's always been a frustrating thing, if you ever talk to a developer, they're probably as hyperbolic of an industry professional as you can ever, ever find. While it's always been challenging at times, we've consistently heard that the last ten years or so have just gotten much, much worse.

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So we wanted to try to get an understanding and quantify some of these delays. And we focus -- we're a housing organization, so we're really pushing on kind of a housing piece of it. But we asked the three investor-owned utilities to basically provide data on the queue for interconnections for both commercial projects and multifamily projects.

And so you can see breaks out, and this is self-reported data from PG&E, SoCal Edison and Sempra, where PG&E, far and away, has the longest and largest queue. They certainly have the largest service areas as well. And SoCal Edison definitely has fewer in the queue. And then in San Diego, they've actually got nothing longer than 30 days. And on the graph on the right, you can see for the multifamily really where our focus is, where a lot of these delays are occurring based on the actual county.

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We also wanted to get an idea of some of the historical timeframes. And after hearing, you know, some other folks, and there are certainly examples of folks waiting months and years, on the left is PG&E, SoCal Edison on the top right, and then Sempra on the bottom right. You can see again, these are self-reported times of how long people are actually waiting to get energized in the multifamily space.

And so for some of these, especially SoCal Edison, I mean, it's literally a week or two, which feels, I think for everybody here, pretty reasonable considering how complicated it is and all of the moving pieces. And Sempra has had, it looks like, some more delays in the past, but they've actually very much gotten that number down over the last few years, so projects are getting

connected faster.

As was brought up by Cliff earlier, this has gotten a lot of political attention. I think it really started maybe in the middle of last year. I started to hear it more and more. And if you jump to the next slide, we've had a lot of recent press coverage, especially again, kind of hammering fairly or unfairly against PG&E.

These were all corresponding with a bill that we were sponsoring with state Senator Scott Wiener. There was a recent claim by the City of San Francisco that total delays on the multifamily housing projects cost the city of San Francisco on affordable housing, $41 million. And that wasn't just for the interconnection, that was for kind of the whole spectrum of challenges working between the municipality and the utility companies.

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So this is actually where some, quite frankly, juice is actually starting to get created. So we co-sponsored a bill with the Construction Employers Association. And I see actually a number of people in the audience we kind of talked to throughout that process. We originally had that the IOUs would be required to connect all new projects to the grid within an eight week timeframe or pay a 25 cent carrying cost per square foot per day on that delay.

There was, a competing bill is probably the wrong way to say it, but another bill in the same space from Senator Becker. And this was actually sponsored by, I'm not actually positive if it was IBEW -- yeah, the Coalition of California Utility Employers, and the electrical workers generally are actually sponsoring this bill with Senator Becker, recognizing this challenge. And our bill effectively got amended. And I see I put September 20th, it's actually also September 30th, 2024.

So what SB 410 does -- and I really recommend everybody looking at it, because for all of the conversations about, hey, we need to create a process so we can actually figure out rules around this electrification, Senate Bill 410 does that. It requires the CPUC -- congratulations to everybody that will have to work on this if it passes -- establish a working group by March 1st, 2024, to propose processes that would improve the ability of electrical corporations to be informed well in advance of needed distribution system capacity for future housing, building electrification, electric vehicle charging infrastructure, and other activities that require increased distribution system capacity, and by September 30th, not 20th, 30th, 2024, try to set targets for what these connections, like how long they will actually take.

And if a world where both of these bills pass, we

also give the CPUC power to potentially impose a fee on the actual IOUs themselves in order to reimburse the applicant for, again, those delays that take time.

There are a number of other bills on this issue. Assemblymember Wood, AB 50 is another one that's in the space. But I mean, it is not understating that the legislature has heard about this. I know that the governor's office have had conversations with Jason Elliott. If folks know who he is, he works on housing. They have heard this really consistently. And so the energy to actually fix this problem, no pun intended, is there.

So always the most important thing -- next slide -- is recommendations and how we actually get there.

So this first piece is, I think, pretty common sense and everybody can probably get on board with this. Everybody wants firm and predictable timelines for each part of the process, including the interconnections or energization. Having some sort of financial carrots-and-stick model to really incentivize that improvement, we think makes a lot of sense.

We had a conversation. I think he's still here. Edward Randolph recommended looking at Hawaii. They have an interesting model where they look at carrots and sticks. And I believe the next panel, somebody from Hawaii will be

on.

And it's a little bit of a challenge because some of this is, quite frankly, essential infrastructure. And when we set up our systems in a way where there's only one game in town to be able to do something, we expect them to be able to do it in a timely fashion. If not, and we have no other recourse, it makes it really, really difficult.

So trying to figure out how can we both create those financial incentives, and if it's resourcing challenges, people are paying for interconnections, so that should help solve that problem but we totally understand that what companies are asked to do is really significant, and at the same time, we actually do need to move on these things. Because it's not just housing or commercial or any one type of industry that is being impacted by this, hence the very broad range of industries here today.

And we are a big, big believer that outsourcing that work to qualified third parties, whether they're subject to a collective bargaining agreement, we totally understand the politics of that, that that will do a lot to make it go faster.

Next slide and that is it.

MR. RECHTSCHAFFEN: Thank you, Corey. And just to add to one of the points in your last slides, in California, the way we've typically done rates, the PUC,

the utilities do not earn risks -- they do not earn incentives or suffer fines or penalties if they don't meet certain targets. We haven't done very much performance-based rate making with some exceptions, but we haven't embraced it in the way others have. So that's one solution, as you mentioned, being looked at by the legislature.

So I'm going to invite all the panelists to come back on and I'm going to have a few questions. We have a few minutes and then we're going to turn it over to the dais.

Let me start with all of you and just ask you to identify maybe one or two of what you think are the best practices that have been adopted by one utility here or somewhere else that you think should be more broadly implemented? To the extent you haven't already flagged that in your remarks, are there other things you could say are the most important best practices you'd like to see more broadly adopted?

We can go in the order that people spoke and so we can start with Francesca.

MS. WAHL: Yeah. Great question.

I would say one thing that was talked a lot about, not in this particular context that in the previous panels, is in terms of sharing information both ways from a

transparency perspective, so, you know, information from the developer side in terms of the pipeline, but also vice versa from the utility side in terms of capacity constrained areas, expected timelines for each step of the process. That has really been helpful. What is the utility holding itself accountable to? So we as a developer understand how much each part of the process should take.

And then to go along with that, dedicated staff has been really helpful. I know that's kind of gone back and forth depending on the budgets across the utilities and how many applications are being done. But, you know, not just dedicated staff on the intake side, but also on the construction side potentially in terms of looking at, you know, who's working on what types of projects and standardizing that part of it. Because while many of these projects for charging can be different, they all look somewhat similar to some extent. And so there can be some level of standardization that starts to take place, even though we're not really at the cookie cutter point yet.

MR. RECHTSCHAFFEN: Thank you.

Rachel, anything you wanted to highlight?

MS. MCMAHON: Sure. And there are two points that I went over in my opening comments.

So one is, and we can point to it, this is the

cost-sharing model that I mentioned for behind-the-meter resources that are not exempt from the cost of utility upgrades. The cost-sharing model that I mentioned is used in the Northeast, like New York and Massachusetts. So there certainly are models in those jurisdictions for California to look to.

And then also, and I noticed Corey mentioned this on his last slide, the recommendation to allow third parties to do some of the work in order to expedite the installation and operationalization of these technologies.

MR. RECHTSCHAFFEN: Thank you.

Henrik?

MR. HOLLAND: So in our experience, as well, whenever we can get a positive and kind of constructive dialogue on capacity availability, that's super helpful in the areas where we are developing. So having more up-to-date and reliable information on grid choking points, available capacity, and what plans are for capacity expansion is super helpful because that really allows us then to plan our portfolio. And we've seen some good movements in that direction.

I mentioned temp power in my presentation. So coordination on running temporary generation solutions for a period of time and aligning that with the utility service delivery process has been something that is new for us in

utilities but is an important area where we've seen some great movement.

And the dedicated staffing has been mentioned. I think we need to be a little careful. And I see a little bit of that of kind of solving process issues with just more people to expedite things. So I think it's a little bit of a balance where we've definitely seen improved performance from, you know, having a committed account person who really sees things through from start to finish on a project. I do think that there is a little bit of, okay, let's put some people against things that are really kind of stuck from a process perspective.

So those are the three things that I'd want to highlight.

MR. RECHTSCHAFFEN: Can I follow up with you about your temporary power idea? What's the roadblock to doing that under the current system? And have you been doing it elsewhere in other jurisdictions?

MR. HOLLAND: Yeah. The two jurisdictions where we've progressed this solution in California are in LADWP territory and in SCE territory. And we have a system up and running in Illinois as well. So the system in Chicago was not an issue whatsoever. With SCE, that's been a good process as well. With DWP, it's been a little bit trickier because of the city charter they have around being the sole

generator of energy in their territory. Really constructive dialogue working that through, but that's the experience that we have.

MR. RECHTSCHAFFEN: Corey, did you want to add anything?

MR. SMITH: You know, I think the three did kind of touch on everything. I just kind of want to give an extra plus-one to that idea of communication between all of the stakeholders.

I joke that wouldn’t just a shared database that could be donated from somebody in this audience and just a simple, hey, we're going to work off the same document and we're going to have our notes shared instantly between a project applicant and a utility company and a city and county, it feels like very Google business model 1997 and is something that I think is a huge barrier today, because it's not always the cost that is the biggest fear for at least residential developers. It's the uncertainty. And oftentimes, you know, they'll be willing to pay for that upgrade as long as they can know that that upgrade is going to happen in a certain period of time.

What practically happens is project applicants will go to a site expecting that that's the day that it's going to get interconnected because that's the day that the appointment was set and then the IOU just doesn't show up.

And they've coordinated all of these things and they had no idea that the utility company wasn't even going to come, and then they get the email of, hey, we had an issue.

So communication between all the stakeholders, like every part of life, would do a lot.

MR. RECHTSCHAFFEN: Well, let me follow up and turn it around a little bit on the communication part because I heard all of you talk about greater transparency and visibility into capacity limits and expected timelines.

The utilities told us, and they've said for a long time, they want earlier intelligence, especially for larger distribution projects. They want fleet owners, they want everyone to share development plans as far in advance as possible and to anticipate what customers need so it's not a just in time deployment. Can we do that? It's impossible to do it completely but can we be, can the developer community be better at anticipating where the needs are especially now that we have state policy more firmly in place?

So I'm going to start -- this time I'm starting with you, Corey, even though you may not have -- it may be a different set of clients or groups that you're representing, but just to be fair we'll go in the opposite direction.

MR. SMITH: Yeah. I mean I think that

residential builders would have zero issue sharing every piece of information they possibly can at the earliest possible point if that would help with things.

What does happen now, just as an example of how broken the system is, because project applicants know that there's going to be a delay, so oftentimes they'll apply before they're even ready just with the intent of getting into the queue. Then the utility company is sitting there going, well, your application is not complete we need more information to do something, and then they spend time on that and dealing with this back and forth.

So there's definitely improved communication and transparency that can happen from the developer project applicant side to the utility companies 100 percent.

MR. RECHTSCHAFFEN: And, of course, we've seen that process replicated on the on the front-of-the-meter side, and Henrik talked about it, that's one of the reasons there's so many projects in the clusters because people are afraid their project won't get approved. And we heard the utilities this morning talking about it and PG&E said something like two-thirds of interconnection projects or large interconnection projects don't see themselves to the end. So there may be reforms needed on this part of the process to help deal with that.

Okay, Henrik, how about you, early intelligence?

MR. HOLLAND: Yeah, and to your last point, but that's what we point to in our comments, as well, is that these queues are really jammed up with these projects because people throw them in because it takes so long and you get a whole bunch of projects in there that will never materialize.

From our perspective, yeah, the answer is, yes, to your question: Can we be/are we willing to be more transparent and open on development pipeline? The short answer is, yes, absolutely. And I do think with the largest IOU in California, we have, I think, a really good open dialogue about where we see that load materialize.

Some of the challenges with the EV projects can be that you really need to point to vehicle acquisition plans. When you're a developer like us, like we don't buy those vehicles; right? So completely understand that there has to be a view of load materializing.

The challenge that we see with some of the programs that are out there is you have to demonstrate a vehicle acquisition plan, a developer doesn't have that plan, so now you're stuck in the situation where until these vehicles have been ordered on a six-month delivery timeline, boom, right, you only have six months now to get your project up and running. Well, that's going to take 18 months, so now you have vehicles sitting idle. So super

interested in deepening that collaboration on pipeline.

There's a few things on the EV side as it comes to figuring out how to get certainty on load that, I think, would unlock a more rapid deployment of infrastructure in advance of vehicles making it the sites to avoid the risk of having stranded vehicles.

You're on mute.

MR. RECHTSCHAFFEN: Sorry. Thank you for those comments.

Rachel, did you want to add anything on this point?

MS. MCMAHON: Sure. So I'll agree with everyone that greater communication is always beneficial in these processes, as is in life, as one of my co-panelists mentioned.

One quick comment, even though we are talking about the distribution system, but the issue of there being so many phantom projects, so to say, and the transmission queue clusters, that's historical. And it's largely just because of the chicken-and-egg process. And I'm speaking specifically about stationary resources, not electric vehicle fleets.

Because of the chicken-and-egg in the contracting process, like in order to show that you're viable and responding to a utility RFP you have to show you have a

queue position or show you submitted an interconnection application, so there's this timing game that happens between all these resources. I think that, you know, if a cluster cost-sharing process were also created on the distribution side, which is one of the recommendations that I mentioned earlier, I think there may be ways to manage around basically kind of recreating the same thing that exists on the transmission side, given the fact that these installations are largely kind of customer driven.

MR. RECHTSCHAFFEN: Okay.

And Francesca?

MS. WAHL: Yeah, I'll just add from Tesla's perspective, because we are a manufacturer of EVs and a developer, we sort of have a unique view into, you know, we know vehicle demand to some extent and what we need to meet. So as a best practice, we try to share our pipeline at least three years out with our utility partners. As you get further out it's obviously not as specific, but we can still say, you know, in this particular area we expect to need this many megawatts of service, so at least we can have that shared with our partners.

So definitely something I think we can be doing more of but certainly knowing that as we get further out it's a bit, you know, less location specific and we have to look a bit broader in the territory.

MR. RECHTSCHAFFEN: I wanted to note, and some folks may know this already but the California Transportation Commission has identified high priority freight areas, and also been looking at the number of chargers we need statewide, as well as on those corridors, to meet our EV goals.

And I hope that as part of that they will identify the best areas on the corridors in terms of a whole range of criteria that some of you talked about for where charging should be to provide more certainty both to the utilities and the fleet owners. That seems to me to be a very promising initiative by the California Transportation Commission. I don't know if anyone wants to -- has been following that process as it's been going along.

Alright, let me ask a couple more questions and then we'll turn it over to the dais, and anyone can jump in here.

I haven't heard anyone talk too much about the need for more permit streamlining at the local level, although that was -- it was certainly mentioned that that's an important factor. Any important recommendation folks have on that area? Anything that's really irksome at the moment?

MR. SMITH: I mean, I can jump in a bit.

MR. RECHTSCHAFFEN: Yeah.

MR. SMITH: So this kind of goes back, right, because a lot of these things, you do have to touch multiple agencies and different jurisdictions. We sponsored a bill last year that was just related to housing where comments needed to happen within 30 days or 60 days based on a size of a project. And, you know, I think putting timelines around that type of communication that is both reasonable but keeps the ball moving is helpful.

And then kind of re-upping everybody's kind of communication piece earlier, if there's timelines and there's more communication, and potentially the applications coming in are higher quality because we fixed the system, I think the entire chicken-and-egg problem goes away a little bit, definitely a part of it.

MR. RECHTSCHAFFEN: Any other thoughts?

Go ahead, Francesca.

MS. WAHL: Yeah, I was going to add I did have right-of-way permitting on our slide, you know, and that being a cause of delay. And I think there, really, the challenge can be, and we call this part of clearing dependencies with the utility, and so if the utility is managing that process and we're not managing it, sometimes it's hard to perfectly understand what the challenge is with getting that cleared through Caltrans or another

entity who's responsible for that.

And so I think there's definitely some room for improvement there, but I don't have any great silver bullet to say this is exactly how we do it, but definitely something that impacts projects and can add, you know, three to six months to the timeline.

MR. RECHTSCHAFFEN: Fair enough.

I wanted to ask you, Francesca, while the mic's open, one of your recommendations in your slides is to provide, you call it provide beneficial EV line extension treatment. What does that refer to? What do you have in mind there?

MS. WAHL: Yeah. Good question. I think this is like the last slide that I actually didn't get into which is more of the kind of national slide that I threw up in terms of what we see across the country.

I would say, you know, in California on the IOU side, we now have Rules 29 and 45, and so they are addressing that part of it, especially having the energization timelines target tied to those projects can be really helpful.

On the municipal utility side, you know, you don't necessarily have that same process replicated yet, so there might be an opportunity there to work with the municipal utilities to look at something similar,, and

maybe it's part of a make-ready program or it's just part of the standard, you know, new service process. But that might be something to look at to kind of conform a bit more with what's happening on the IOU side.

MR. RECHTSCHAFFEN: Great.

Okay, I'm going to open it up to the dais now. And if anyone has any questions for our panelists, raise your hand.

Commissioner Monahan.

COMMISSIONER MONAHAN: I am raising my hand very politely Mr. Rechtschaffen.

This has been a great panel.

Oh, and I also want to recognize that Commissioner Shiroma has joined us, so welcome Commissioner Shiroma.

And I want to follow up, actually, on something that Henrik said, which I hadn't realized that there needed to be a demonstration of the vehicles coming before you could get approval for infrastructure. Can you just tell me a little more about that? That's the first time I've heard about this.

MR. HOLLAND: Yeah, specifically let me point to the Charge Ready for Transport Program that is administered by SCE. That provides a level of funding towards the front-of-the-meter infrastructure, and even behind-the-

meter, if you can demonstrate a vehicle acquisition plan. So that's an example of a program that's been designed with that particular item in mind. And, look, I think that kind of -- I understand what the intention is of that because that ensures that there is load certainty on the customer side.

As I said the challenge with that program for the industry is that the developers and the infrastructure owners and operators are oftentimes not the entities that actually procure the vehicles. And that's kind of the dual challenge of the EV industry is that you have the chicken and the egg of the infrastructure and the vehicles.

Sometimes our customers don't even own their own vehicles, right, so they lease vehicles from a fleet management company. And in some cases then a lease is not a sufficient proof point to make an application into a program like that.

So that's the kind of -- just to make it very tangible, that's what I'm pointing to.

COMMISSIONER MONAHAN: And maybe, Cliff, you might know the answer to this, but is this specific to SCE and Charge Ready or is this more applicable?

MR. RECHTSCHAFFEN: I don't know the answer to that.

COMMISSIONER MONAHAN: It's an interesting one

because, I mean, we faced this with vehicle incentives and we --

MR. RECHTSCHAFFEN: Yeah.

COMMISSIONER MONAHAN: -- you know, have the problem with like a school district will get an incentive for a school bus and then they're like surprised that it takes another year to get the charger. And it's a problem because the school buses, they want to transport kids and it's sitting there idle, you know? So we're experiencing that too.

MR. HOLLAND: Absolutely. Yeah.

And just to answer your question, so PG&E has a similar program, so I'm pointing to SCE CRT. That's the program that we have most experience with, but we've seen that with the PG&E program and with a number of out-of-state programs as well. So what we then end up doing is having to look at, well, what's the funding available for public charging infrastructure and can we then tap into that? But that doesn't really meet the needs of customers today who are looking at fleet electrification as these are kind of private behind-the-meter charging type projects, which is really the type of projects that near term are going to get the industry going.

MR. RECHTSCHAFFEN: Commissioner Gunda.

VICE CHAIR GUNDA: Thank you Commissioner

Rechtschaffen. I think I struggle with not calling you Commissioner either. I mean, you did say that you needed a longer title, so I will say former Commissioner Rechtschaffen, thank you for moderating the panel and a really wonderful presentations. And thank you for the questions that you brought out.

So a couple of questions to Henrik, just if you could kind of frame this? So we are talking about, you know, that you have the overarching issue of the transmission that we discussed last time, we're talking about the distribution now. You know, I'm kind of just contextualizing this in a little bit of the trade-offs; right? I mean so we have lots of work to do very quickly. We have to green the grid very quickly. We have to do the electrification. So I'm kind of like in this in the space of trying to figure out grid solutions; right?

And then one of the grid solutions that you kind of pointed to was how can we have onsite generation that's not necessarily plugged in --

MR. HOLLAND: Yeah.

VICE CHAIR GUNDA: -- you know, to the broader grid.

So I think starting off with that, you know, how do we scale those kind of near-term solutions to enable electrification -- I think it goes to, Corey, to you as

well -- when we talk about this in kind of trade-offs? You know, do we want to do -- what do we want to do? We want to electrify first? Do we want to green it first? You know, how do we tackle these timelines?

Do you see opportunity as we think about decarbonizing from the gas system? You know as Henrik is pointing out, there's opportunities for onsite generation to potentially electrify, you know, multi-residential, right, you know, homes. Like how do we think about this? Any high-level policy ideas on two elements, how do we build consensus and thinking around the trade-offs, and how do we land some, you know, near-term solutions that does societal good as we are continuing to transform the broader aspects?

MR. HOLLAND: Yeah, just to give you -- thank you for the question, Commissioner. I think that we have such an ambitious set of goals ahead of us that over the next, you know, decade, it's kind of we need all of the above to really move the ball forward.

So the temporary and distributed generation-type assets that we -- that I just talked about today and that we have been looking at for near- to medium-term solutions to electrify, you know, to create a lot of power onsite for these heavy-duty fleets does have a renewable natural gas component to it, a natural gas or renewable natural gas

component to it.

The asset that I showed on the slide was a gas turbine that we were feeding near LAX with renewable natural gas. So there are that type of near-term options. But if you think about linear generation, for example, coupled with storage and onsite solar, linear generation technology can run on natural gas but as technology advances on green hydrogen as well. So you can create a pathway to net-zero with these technologies that can start with near-zero emissions to something that is net-zero to even, you know, negative CI if you think about renewable natural gas.

So that's kind of how we think about it, that because of the significant objectives ahead of us we really have to think about how at the grid edge we can do more to bring power to customers that has a benefit of expediency but it also has a benefit, too, on the resiliency side of things and T&D investment deferral.

So that that's kind of the key point that we wanted to make, that it would be awesome to look at frameworks that would allow developers and private operators to progress that type of project.

COMMISSIONER MONAHAN: Does that exist anywhere, you know, in another state? Have you seen in any state that has a process that would encourage that?

MR. HOLLAND: Well, you can point to states that have a much heavier deregulated energy system, such as Texas. It's hard to point to date to projects at superscale that run the technologies that I just mentioned. Linear generation is early commercial and we feel very optimistic about that technology. But I'd point out, you know, Texas is a state where there is a lot less regulation on private developers and operators.

But we can definitely follow up with a more in-depth assessment of what markets we think are, from our perspective, more conducive to that type of deployment.

MR. RECHTSCHAFFEN: Can I jump in with a question, a quick question?

Is there any sense in your -- any of the groups you're speaking on behalf of or just in your experience that the information the utilities are requiring needs to be more standardized or easier to understand, or are the expectations that are being imposed on developers clear and comprehensible right now? Is that an additional problem that we need to address?

MR. SMITH: I'm hearing it's a little bit of both. And in my conversations, specifically with PG&E, I know they're doing more to kind of front load just like the questionnaire, hey, here's all of the information that we're going to need at the beginning of the process. That

would certainly make things work smoother.

To the point earlier, though, the earlier you are in the process, sometimes you don't have all of that information. And then so you want to make sure you've got this situation where you can keep that communication going.

But just kind of a similar example. In cities and counties, when we get back to this permitting idea, we found that cities that post template permits, examples about what the permit is supposed to look like, those cities see permitting go at about a 70 faster rate than cities that do not share a template on the front end.

So those little those little pieces can absolutely make a difference by just kind of giving somebody the, hey, here's how it's supposed to look. Because it's not just project applicants then that are doing it. Coming into the queue you've got your mom and pas and your non-professional folks who would really have no idea because they don't have a developer and an architect and a land use attorney that are also clogging up the system.

MR. RECHTSCHAFFEN: Thank you.

Did anyone else want to comment?

Commissioner Shiroma.

COMMISSIONER SHIROMA: Hello Commissioner Emeritus Rechtschaffen. Nice to see you. Thank you for

the excellent panel and the moderating facilitation.

I'm sorry I wasn't here for the morning sessions. I looked at the slide deck. It looked like some really good and very dense stuff. This stuff is complicated.

One of the things in this afternoon's panel is about capacity availability, and that if developers, whether it's housing, heavy-duty electric vehicles, electric vehicles, microgrids, renewable energy, developers and so forth, that if the utilities are able to show the landscape of where, where is there opportunity to develop, that that would be a tremendous thing.

Did I understand that correctly from the panel? You can just nod your head if you like. Several of you mentioned capacity.

So this is not so much of a question, and the Commissioner Rechtschaffen has done many general rate case. I have had a few and I have thought that, you know, if we more clearly had a five- to seven-year plan, taking us out to 2030, of all of these requirements, aspirations, deadlines and what have you, and had a keen knowledge of the grid capacity that we could more clearly direct the IOUs on -- I'll call it, for lack of a better way to put it, priority capital investment areas and needs, and folded into that would be an equity attribute to it. Because it would be very easy to just focus on heavily urban areas,

but people do travel to less urban areas and do business from less urban areas.

So anyway, just thinking out loud, folks. I do appreciate the conversation. And if anybody has any anything they want to add, in reaction to my thinking out loud, please feel free. Thank you.

MR. RECHTSCHAFFEN: Commissioner Shiroma, actually this morning, and you may have missed this, but at least one utility, SDG&E, was talking just exactly about that, about better, you know, getting ahead of the work in the GRC. Their argument is it's a little too rigid. It doesn't take into account what customers will need to do down the road as opposed to the next couple of years. So that did come up, but I'll let other people on the panel respond if they wanted to.

MR. HOLLAND: Just a comment from the perspective of -- and thank you, Commissioner, for those comments -- from the perspective of a developer very much focused on the logistics commercial vehicle segment.

So to give you a sense of how we identify where we require infrastructure, we look at where the trucks go; right? And to a large extent, because we are a logistics real estate company, we know where that is to some extent. That's our facilities; right? So last-mile delivery vehicles domicile in warehouses, they domicile close to

warehouses, they do overnight charging there, boom. So that's kind of a sure shot.

As it comes to drayage, for example, which has become an area of focus over the past two years, very much driven by the work that CARB is doing, these are quite well identifiable routes. So as we look at where things need to go, where capacity is required, looking at where -- looking at the travel patterns of trucks in different segments gives a really good indication of where that energy load is going to be required.

MR. RECHTSCHAFFEN: Thank you.

President Reynolds has rejoined us tonight. I see she has her hand up.

PRESIDENT REYNOLDS: Thank you, and thanks for the fantastic panel. Really good to hear from all of you. And I appreciate the different perspectives that you all bring, so super interesting.

I have a question for Henrik, just, you know, the work that you're doing, it sounds like, you know, you have a lot to manage, a lot of, you know, complex factors that you're balancing. And I just want to pick your brain a little bit on how much your calculations depend on the state of the grid now, so -- and let me explain what I mean by that.

You talked about solutions like linear generators

and, you know, some of the electricity generation work that you're going on, you're looking at renewable fuels. If the grid was 100% clean now, would your decisions be different? So what's driving them? Are you looking at ways for redundancies because you want to ensure the power will always be there when you need it? Are the rates too high and you're looking for ways to reduce rates?

So if you took that clean energy piece out of the picture and you just assume we've gotten to our goals, the grid's 100% clean, what do you think would you do differently? And I know I'm asking you to speculate a little bit but I'm really interested in your thoughts.

MR. HOLLAND: Yeah, I think the grid being 100% clean is one thing. I think near term the challenge that we're really solving for with a higher priority is just available capacity and timelines expediency; right?

So to be frank, look, if the grid was 100% green and we could get the capacity where we needed at a cost effective rate then, yeah, we wouldn't be looking as heavily at distributed technology, like linear generation, to be frank; right?

So I do think in the reality of a system that is our grid, the expediency and the resiliency kind of go hand in hand. But I want to put that out there that for us for now, we're looking at distributed architectures and kind of

systems templates for capacity, resolving capacity availability issues and expediency timelines. We are, as I said, we're committed to net-zero, so anything that we do will either be zero or near-zero short-term with a pathway to net-zero.

So that that's kind of how we think about the net-zero kind of phasing near term, like our customers need capacity today. They need it today, they need it 6 months from now, 12 months from now, and we simply don't have, in many of our logistics clusters, and with a cluster, I mean a conglomeration of warehouses, we don't have 36 months to bring charging online; right? We have customers with trucks that are literally sitting in the yard. So that really near term is the most urgent priority that we are solving for.

But again, I want to underline that as we think about these decentralized generation options even if they are not completely zero today, they are on a pathway to net-zero.

PRESIDENT REYNOLDS: Got it. That's really helpful and completely understand.

How much of your -- are you constrained by your sites or would you ever, say, look at the grid first and maybe go to a place where there is sufficient capacity?

MR. HOLLAND: Yeah, absolutely. Look, where we

deploy charging is an optimization of many things. With front-of-the-meter storage it's a little easier to say, hey, let's look where the capacity is and then we'll site a project there.

With vehicles, well, it's kind of like with real estates, it's location, location, location. It's the same with trucks; right? So we want our packages delivered to our homes. That means that these trucks need to be in a certain area from where we live. So location is first of all determined by what the most optimal position is for that fleet. Then we look at available capacity. But, of course, there's an iterative process there.

There's an area, it's Hunter's Point, there's a substation that is completely oversubscribed, tons of logistics behind it, and there's just, what we understand today, no way that we're going to get any capacity there in the next five years. And there's a huge amount of logistics being done out of those facilities.

So that's where we're looking at, okay, what do we do? Let's do linear generation solar and storage to see if we can get something up and running there and help our customers; right? Because at the one hand, you know, they have mandates, regulation coming in, but on the other hand, you know, there is this problem of not having that capacity available and us not being able to help our customers at

those locations.

So absolutely, we look at station capacity. But, yeah, we're kind of stuck between a rock and a hard place many times.

PRESIDENT REYNOLDS: Yeah. Really interesting. Thank you for those specific examples.

MR. RECHTSCHAFFEN: So I understand we can -- we have a few more minutes, Heather, you can correct me if I'm wrong, to extend the panel a little bit.

So Commissioner Monahan and Commissioner Gunda have questions.

So Commissioner Monahan, please go ahead.

And thanks everyone for staying on a few more minutes. We do have a slight bit of slack in the schedule, apparently.

COMMISSIONER MONAHAN: Yeah, I'll be fairly fast.

I mean, we've talked about solar and storage but not load management. So just curious if load management is part of the strategy and whether there's the right incentives for load management?

MR. RECHTSCHAFFEN: Who wants to take that?

MR. HOLLAND: I'm happy to.

I'm sorry, Francesca. Go ahead.

MS. WAHL: No, I was going to say I can jump in a bit.

But I think load management definitely has a role to play. And I think part of the challenge with fast charging, right, is the on-demand service that you're providing, and so we're always hesitant to impact the customer experience. That doesn't mean that we can't have applications that provide some level of load management because we're, you know, rarely ever going to be in a situation where every single vehicle is going to be pulling max capacity off of that site, and so there is some opportunity for that.

We've always thought more about the AC charging Level 2 space that's a bit more flexible for the load management component versus the fast charging since fast charging is so unique in that way. So I think that's where we see a better application of that as the more flexible load.

And I will just add to the discussion around solar and storage. You know, we look at solar and storage for many of our fast charging sites in California and oftentimes, you know, it's more of a locational issue to be able to include that onsite than anything else. But we think about that, you know, from a resilience perspective, as well as other factors that we weigh in. So it’s certainly something we'd like to have more of or see more of, but definitely, you know, much harder in an urban

setting than, you know, in a highway corridor, more rural setting where we might have the space to be able to add it.

But you know, we'll never have, probably, the onsite capacity to serve that entire station. We'll always be grid tied just because of, given the loads we're talking about and, you know, the larger and larger projects that we're starting to build in the 5 to, you know, 10 megawatt range, whatever that looks like.

MR. HOLLAND: Building on that, the same goes in the logistics sector, just as I outlined that location for fleets is really important. So it's hard to put the energy system first and then look at location.

Similar in load management. So fast charging, if you're doing drayage, these fleet operators need to charge when they need to charge; right? So it's really hard to constrain charging with load management to manage, you know, peaks or anything like that because these are critical operations for those fleets.

Some of that load management could be bought with a storage system. But, again, that comes with a with a cost. And oftentimes that's, frankly, just not in the money. Level 2, so overnight charging, those types of applications are much more supportive of load management overall.

So it's a really, really important topic, but it

will be more challenging for specific use cases than others.

MR. RECHTSCHAFFEN: Commissioner Gunda.

VICE CHAIR GUNDA: Yeah, thank you.

I think you actually answered the question, I mean, that I had; right? And I might want to just extend that just a tiny bit.

In terms of, as you think about the value proposition, Francesca and Hendrik, of deploying this additional capacity, right, so you're thinking through, I need additional capacity, you know, I have, you know, my business case that will be supported by this additional capacity, two points there.

One is how do you place the premium; right? Like from a value perspective, I mean, how high would you go, right, from -- in your calculations?

And two, how are you partnering today with, you know, geographically located other businesses, you know, to potentially co-optimize the opportunity of onsite generation to think through this?

So before I before I hand it off to you guys for answering I do want to note on record that Commissioner emeritus Cliff Rechtschaffen translates to CEC Rechtschaffen. Just wanted to close that.

I'll hand it off to you guys.

MR. HOLLAND: I'm happy to jump in. Thank you for the question, Commissioner.

I think the capacity premium, frankly, I mean we're in a commercial business, right, so it will depend on the customer application and the overall total cost of ownership of an electrified solution which includes not just the grid cost and energy cost but also the cost of the vehicle. So it's important to look at total cost of ownership of the full EV stack as we look as Californians at like how this is going to work; right?

So the promise of electric vehicles is that there is a lower energy cost, lower maintenance cost, but definitely right now a higher upfront vehicle acquisition cost. Now if that energy cost starts to move more, starts to move north, it's going to eat into the TCO of the overall EV stack. So that's something that customers are, I'd say, starting to get a better sense of because this is new. But I think that is something that we need to be really careful with.

So we look at the cost of grid versus distributed cost. And we're actually seeing that, in some cases, installing a temporary generator or longer-term, even a linear generator, that's their longer-term, is oftentimes even more cost effective than a grid connection. And that's okay. Like I think as long as the environment, the

policy environment allows private operators to develop that, I think that could be a great, great solution. And we should figure out then how we build those price signals into the system.

So I hope that answered your question a little bit. And then there was a second part, but to be frank, I kind of forgot what the second part was.

MS. WAHL: I was going to also ask what the second part was but I was.

But I was just going to jump in and say, you know, we have explored opportunities to take on more of the costs, right, especially to get this this moving in the near term. We don't think that's maybe a scalable long-term solution but definitely something that, you know, looking at that premium of being willing to be pretty risk tolerant in the near term in order to get projects moving.

VICE CHAIR GUNDA: So the second part was just kind of thinking about given how big your businesses are and you have the opportunity to anchor these onsite generations, you know, are there opportunities for you to collaborate with geographically-located smaller entities, you know, to really optimize?

MS. WAHL: Yeah. One thing I will say is we do sometimes co-locate with other charging developers. That is a strategy that we have taken. And the, also, if we can

go into a new commercial development and leverage some of California's great EV-ready building codes and work with other partners to be able to come together, whether it's a new Target and some other larger property owner, we might do that as well.

So there's definitely been opportunities to try to work with other developers.

MR. RECHTSCHAFFEN: Alright, I think we're at time. Thank you all for a very interesting and lively panel.

And I'll turn it back to you, Heather.

MR. WENDER: Maybe I'll jump in instead of Heather and just offer my sincere thanks. Thanks to Cliff for bringing the moderation game up a level.

I'm sure the attendees are delighted to have some high-caliber moderation for our next panel, as well. I want to introduce Ethan Elkind. He is Director of the Climate Program at UC Berkeley School of Law's Center for Law Energy and the Environment. He has graciously agreed to moderate this last panel.

Ethan, take it away.

MR. ELKIND: Great. Thank you, Ben and Heather and Commissioners. Great to be with all of you. Hopefully not a big drop off from having Commissioner Rechtschaffen moderate the panel but I'm really pleased to be here

moderating this next panel, also very focused on solutions. And this one is called Technologies, Processes and Regulatory Strategies to Improve Distribution System Connections. We've got a great lineup of speakers here to kind of bring our panel portion of the IEPR home here.

I'm just going to make a couple points as moderator. I wanted to highlight some of the work that we've done at Berkeley Law School Center for Law Energy and the Environment.

So just touching on some of the issues that have already been raised, one, I want to talk about the opportunities for improving data access. I know we're talking a lot about interconnection. But if we can improve access to data on the distribution grid, that has the opportunity to really open up a lot of efficiencies and improve a lot of these processes, I think, that we've been highlighting in the discussion today.

And I want to flag a report that we put out at CLEE in conjunction with the Emmett Institute down at UCLA Law School called Data Access for a Decarbonized Grid. We put that out in February of 2021. It has a whole bunch of solutions. I'm going to put it in the chat here. I don't seem to have access to the chat for all the attendees, so it's going to go to the hosts and panelists. And hopefully someone who is more technically proficient than I am can

share it with all the participants for the IEPR today.

But just in a nutshell, that report goes through some of the barriers to accessing data, which includes privacy and security rules, utility and regulatory structures, and a lack of capacity. And some of our recommendations include what we're going to talk about in this next panel, so we talk about adopting performance-based regulation of electric utilities to provide financial incentives for high-quality efficient data generation and management.

We also talk about the need for the Energy Commission and the Public Utilities Commission to create a definitive guide to the legal and regulatory framework governing data privacy and security. We talk about re-examining the 15-15 Rule at the Public Utilities Commission for customer data aggregation which sets the numerical limits on customer cohorts and consider the use of differential privacy methods instead.

We also talk about the need to modernize utility IT systems to adapt to these new technological and customer needs as we're putting more emphasis on our on distributed resources.

So anyways, feel free to take a look at that report. It actually grew out of a stakeholder convening that included now former Commissioner Rechtschaffen and

current Energy Commissioner McAllister, so just wanted to commend that for folks.

And then finally, just on the dispute resolution process, we talked -- we just heard about some of the legislative efforts to try to address the delays on interconnection.

And we at CLEE, working with the California Institute -- for CIEE, so sorry, California Institute for Energy and Environment at UC Berkeley, have been working with the Public Utilities Commission on the AB 2861 process which is a law passed in 2016 to authorize the CPUC to establish an expedited dispute resolution process for these grid interconnection disputes under Rule 21. And that involves the creation of a panel, essentially like an arbitration-type panel.

And I think that process has actually -- it took a while to get started but I think that already seems to have paid some dividends in terms of motivating some solutions to these interconnection disputes for those thornier just interconnection disputes that we heard from the utility presentations earlier today.

So I think there may be some more room for more alternative dispute resolution processes to deal with these interconnection disputes and I just wanted to raise that, as well, for folks working on solutions to this. So

anyways, I hope this moderator prerogative with some comments on improving energy data access and dispute resolution is useful.

And with that, I want to introduce our three speakers today and I'll introduce them in order of appearance and then hand it over to them.

So first we have Grace Relf, who is the Chief of Policy and Research at the Hawaii Public Utilities Commission, where she's going to be talking about performance-based rate making. Prior to her current position, she worked on utility policy at the American Council for an Energy Efficient Economy.

And I will introduce the other two panelists in turn, so I'm actually just going to go ahead and hand it over to Grace now for her remarks and then I'll introduce the next two speakers.

So go ahead, Grace.

MS. RELF: Thanks Ethan. And thanks. Yeah, that's really interesting. I look forward to reading your report that you've mentioned here, a lot of similarities between the work that we're doing here in Hawaii too. I think we just established interconnection dispute resolution process largely modeled off of what you all are doing in California. So, yeah, interested in looking through that.

Yeah, thank you all for having me today. My name is Grace Relf. I'm the Chief of Policy and Research at the Hawaii Public Utilities Commission and I'm excited to share with you some of the work that we're doing here to improve interconnection and use of distributed energy resources. And, yeah, I look forward to learning from my fellow panelists as well.

We can go to the next slide.

So just in general, I always like to start with a little bit of context. In Hawaii, we are out in the middle of the Pacific, so I think sometimes it's helpful just to remind folks of our context here.

Then I'm going to really dig into our performance-based regulation, our PBR framework. I'll talk a little bit about the structure just to give some context about, you know, where we're coming from our guiding principles. And then I'll talk about a specific incentive that we have for interconnection of DERs. And I wanted to also talk a little bit about where we're going with our electrification of transportation data collection and performance management under this framework as well. And then I'll just end with a couple of key takeaways.

Go to the next slide.

So as I mentioned, a lot of similarities between California and Hawaii, so none of this I assume will be too

unfamiliar for you all. But as an island grid system, we really have to focus on resilience. And, you know, I provide this overview too to talk a little bit about why we're focusing specifically on distributed energy resources. And first, resilience is key here. We cannot import any electricity from, you know, neighboring islands, or especially from the mainland. Everything we have is generated here. And, you know, a lot of our resources rely on imported fossil fuels, which we're trying to get off of.

So in that context, you know, distributed resources are a way to make good use of our land and to help with that resilience.

Additionally, DERs can also help with the flexibility component of managing a grid that really does have high renewables right now.

And then finally, I wanted to mention that in the past couple of years we have been dealt a number of challenges with our grid-scale renewable projects being delayed because of the COVID-19 pandemic, you know, supply chain issues I'm sure that everybody is facing, and so we have turned directly to distributed energy resources, DERs, to help face that or, yeah, address the capacity replacement challenges.

Our fossil fuel fleet here is really old. A number of our fossil fuel generating units are, you know,

three times my age, so we are looking to get those replaced and convert over to a renewable energy fleet. And DERs are a major way to help with that.

You can go to the next slide.

And as you know, we have strong state policy here that really helps drive, you know, our objectives and getting everybody on the same page as to what we're trying to achieve. So we have a hundred percent carbon neutrality goal by 2045. We have a strong renewable portfolio standard and energy efficiency portfolio standard. And really our driving motivation here is to address climate change.

I think it's important to know, we have a really high penetration of rooftop solar already; 37 percent of single-family homes in the Hawaiian Electric territories have rooftop solar, and 91 percent of those are now being installed with battery storage. So that's a huge fleet of resources at our disposal that we really should be making good use of.

And I just thought this was an interesting statistic, you know, almost a 25 percent or more than a 25 increase in passenger EVs over the last year. Exciting.

Next slide.

So when we embarked on our performance-based regulation journey we sought to align on what our guiding

principles and desired outcomes were. And this was almost a two-year stakeholder process to align on our priority outcomes.

And I provide this here just to highlight that our guiding principles really do focus on distributed energy resources. One of those in sort of an emergent category, which we define as maybe not within the traditional utility expectations, is interconnection experience. And we also have DER offset effectiveness, so making use of that big fleet of resources on the system. And in terms of advancing societal outcomes, too, we see that electrification of transportation is a good way to reduce greenhouse gas emissions and reduce our reliance on fossil fuels as well.

So you can go to the next slide.

Just briefly, our framework here, it consists of revenue adjustment mechanisms, so this is the major bulk of the utilities revenue. It's governed under a five-year plan and it's basically an allowance that they can operate with that's adjusted annually for inflation and a return to customers.

The second are performance mechanisms. These are really intended to promote those guiding principles that I had on the last slide via rewards or penalties that the utility can earn and via tracking mechanisms or reporting

on our desired outcomes.

We also have a pilot process which is intended to promote expedited review of innovative pilot projects. And then there are safeguards, as well, to make sure that nothing's going too far off the rails.

And I'm going to focus in on these performance mechanisms because I think that's where we've seen a lot of success in terms of DER interconnection progress.

Let's move to the next slide.

For example, I just pulled out some of our performance incentive mechanisms that are related to interconnection. The first is the renewable portfolio standard A, which is RPSA, accelerated achievement of the renewable portfolio standard, and this provides a reward for the utility achieving our RPS goals more quickly than what is in the statute. And they can also be penalized if they do not meet it.

Another one is our grid services PIM. This is intended to promote the utility acquisition of grid services from DERs, so that is capacity reduction, capacity building during the day when there's solar, and fast frequency response as well, and this can be up to $1.5 million in rewards per year.

We also have a PIM that promotes interconnection approval for DERs, so improving the timeliness of

interconnecting DER systems.

And then finally, we do have an incentive mechanism that promotes timely and cost-effective review of grid scale projects.

But I'm going to focus in on the DER interconnection PIM for now.

So if you go to the next slide?

This is the general structure of the performance incentive mechanism, the PIM. And we're really measuring here the average number of days within HECO's control to energize DERs. And you can see that it's basically a reduced number of days over each year, leading to kind of nationally exceptional performance at the end of this five-year period.

You can go to the next slide.

And you probably were wondering how we aligned on those targets. And really, it was just a very comprehensive review of the utility's recent interconnection data, so we looked at -- you know, we sliced and diced that data every which way to come up with some reasonable targets that also led to exceptional performance at the end of the performance period.

Go to the next one.

And the utility has done quite well on this PIM. They have reduced their time to interconnect DERs to, you

know, for Maui Electric, ten days, for Hawaii Island almost not quite 12 days on average, and on Oahu where we see a much higher number of applications, you know, 16 or 17 days as well. So that's a huge, huge improvement; from Maui we were seeing like up to two months at some points.

You can go to the next slide.

I also just briefly wanted to mention that we are tracking a number of metrics related to EVs and electrification of transportation in order to increase how these resources, as they are growing, will be integrated with the grid. So we're tracking fleet electrification, EV energy and demand by time period, EV counts, and then ride share fueling hubs, so trying to promote electrification of transportation for those who may not own their own vehicles.

We can go to the next slide.

Just really briefly, this is showing the metric for fleet electrification. So this is Hawaiian Electric's fleet of EVs. It's supposed to increase every year and their percentage of miles driven is supposed to increase every year as well. Maybe not necessarily doing super well on that one.

Next one.

And then this is the EV load in different time periods. So you can see over the last year the off-peak

charging has really shot up. So I think that's to do with -- just wrapping up here. I see you that that's my time.

So I think I just have one more slide here of key takeaways, anyway, which is just to say that, you know, I think there needs to be pushing from all sides. Performance-based regulation, incentives, policy, all of that can really help to promote interconnection of DERs. And, yeah, continuous learning and improvement is important.

So thanks so much. Happy to take questions.

MR. ELKIND: Alright, great. Thank you, Grace. We're going to just hold off on questions until we hear from the other panelists but thank you so much. It's always wonderful to hear from the Hawaii experience. I think in many ways it's a postcard from the future, at least here in California, with many of the issues that you've had to deal with. And glad to hear that our dispute resolution process might have inspired your work. Always happy to do a site visit to Hawaii if you need more information on that program. So as I said we'll hold off on questions until the end.

Let me now introduce our next speaker, Dr. Karen Wayland, who's the Chief Executive Officer of GridWise Alliance. She previously worked at the U.S. Department of Energy during the Obama administration, has extensive

experience in Washington D.C., as well, working on energy and climate legislation for speaker Pelosi and Senator Reid.

And I'm going to hand the floor over to you, Dr. Wayland.

DR. WAYLAND: Thank you, Ethan. I think I was going to go last. I know, I think, they're working on moving the slides around, unless you want to --

MR. ELKIND: Okay. Yeah, let's. Yeah, I apologize. I knew there was going to be some scheduling issues there but I didn't realize that. So let me stick to the original plan then and apologize if I just created a fire drill for our tech folks. So, alright, well, you heard Karen's introduction.

Now I'm going to introduce our second speaker, supposed to be third but second, Matthew Tisdale, who is Executive Director of Gridworks. He served as a senior energy advisor to the California Public Utilities Commission for many years prior to his current role with Gridworks. And he's going to be helping us talk more about solutions.

So Matt, over to you.

MR. TISDALE: Great. Thanks Ethan. Are you hearing me okay?

MR. ELKIND: Yes, can hear you great.

MR. TISDALE: Excellent. Well, good afternoon everyone. Thank you for the invitation to join the conversation. Grace thank you for warming up the panel and compliments on a nice presentation. I will transition into my remarks with an anecdote.

Grace's former boss, the former chair of the Hawaii PUC, Jay Griffin, is a member of our team at Gridworks. And he has been contributing to our work in support of California, as well as other places. And I was asking Jay recently about this PBR case and the progress that Grace was just reporting on and how it was achieved, really. And he told me this really wonderful story about the very first meeting that they had with utilities and stakeholders who were expressing an interest and stepping into the conversation around PBR.

And he said, "What we did was we formed a circle. And, I as the leader of the process, very clearly and directly explained that it was an absolute priority to accomplish the changes and that the Commission was going to be consistent and have sustained energy towards accomplishing what they were setting out to do, to align the interest of the utility with interconnection improvements."

And he imparted on me as a -- and I impart on you the importance of that clear signal that he provided and

the impact it had on the conversation.

I see a number of wonderful Commissioners and leaders here from the California environment expressing that today, and so I thank you for doing that. And now let's follow through and get to it.

I'm going to play a bit of a sort of cleanup hitter role here. I've been happy to participate and monitor most of the workshop today. And I just want to share some of the high-level takeaways that I picked up on, some of the primary solutions that I heard recommended, and some suggestions on how to triage around those. I hope that will be an aid to you, Commissioners and staff, as you try to digest and move forward from such a rich workshop.

First is that we heard that interconnection and interconnection delays are an equity issue. Electrification and distributed energy resources can provide a pathway out of poverty, can provide advantages to communities that have been disproportionately impacted by our infrastructure in the past. And to the extent that there are delays or hindrances to that interconnection or to that energization, then we're delaying that relief.

And I think that is even moreover emphasized when we think about this as a housing issue. Delays and energizing of new housing and the effects that that can have on our housing markets, it is an equity issue and it

should be treated as one. So that's the first thing I heard.

The second thing I heard is sort of in the regulatory camp. You know, the CPUC and the utilities have an incredible amount of regulatory infrastructure in place to understand how utilities perform distribution planning, how they look at alternatives, whether they be traditional alternatives or distributed alternatives, how they think about electrification in that context.

And I'll just tell you from my personal experience of helping build that regulatory infrastructure over ten years, and also working with other states who are trying to build it, California's regulatory infrastructure in this respect is remarkable in its weight, heft, and might. Yet still, even with all of that in place, it does seem that the current systems of distribution planning are stressed and they're being pushed to their limit by the electrification goals and needs that we have.

Third observation is around workforce. I heard a number of the utilities share that they are ready to grow their workforce to strengthen and speed interconnection and energization. And I have heard other smart friends out and about who are working closely with the utilities that that is welcome, that would be a welcome turn of event, that the utilities simply have a need, an imperative to pick up

their workforce and be able to process more applications and deal with more of these challenges. Now that's a lot easier said than done but I was really pleased to hear the recognition of that challenge and also the utilities interest and commitment to working with it.

So those were sort of three themes I heard on equity, regulation, and workforce.

Turning now to some of the solutions to those themes that we heard that I think are worth mentioning.

First is, you know, treating the challenge of interconnection day delays with the urgency it deserves as an equity issue. And I really appreciated the opening presentation from the gentleman, Mr. Walker, from GRID Alternatives and his suggestion about what are the barriers to a needs-based prioritization for interconnection and energization. I'm really curious about what those barriers are and what could be done about them and I hope that that's something we can dig deeper into as we move forward.

A second solution that we heard was from CPUC staff about applying lessons from the interconnection process to the energization process. Working groups have been a very effective tool on the interconnection side. My team has been involved for years in supporting utilities and interconnecting parties to work through all kinds of nuts and bolts about improving these processes. And those

groups have been very effective. They have ironed out a whole bunch of things that would not be ironed out in the traditional regulatory process.

So I want to endorse the idea that one of the lessons learned from the interconnection side that could be applied to energization is working groups.

Also the integration capacity analysis and the idea of modeling and forecasting ahead to anticipate where capacity is and where capacity isn't has been another effective tool that's made a difference on DER interconnection and can be used on the energization side.

A third solution that we heard, and this goes back into the workforce theme, is really digging in to what the utility workforce is able to do in this respect, sort of what are the person hours that are being spent on interconnection? What is the expertise of the folks who are in those positions? What are their competing obligations? What might they be working on instead?

For example, we've had a lot of these folks, and some of the best ones, spending most of their time on wildfire risk mitigation. Okay, that's also a priority. But if we look into how the time is being spent and where the expertise is being directed and check, is that aligned with the state's priorities, is it aligned with the priorities of the customers of the utility, I think we

would probably learn a lot.

So the last thing I'll do is just try to help maybe with a couple of triaging suggestions. And those are, first of all, just remember that electrification is only beneficial if we have a decarbonized power supply. So if energization is outpacing interconnection, we have a problem. In terms of priorities, having that clean energy available is critical as an antecedent to using it in the transportation fleet.

The second thing is, you know, give us work to do here. And by us, I don't mean necessarily Gridworks. We already have more work than we know what to do with. But give us, the community, the work that you need help with. You're going to need folks who are assembled here today, the great ideas, the energy and expertise they have, to do more than participate in this workshop. You're going to need them to roll up their sleeves in working group settings, in task force, in settlement negotiations, and to hammer out solutions to these problems. So you all at the agencies don't have to solve all these problems, even though you're really good at solving a lot of problems and you get a lot of people. Hand some of those out and put parties to work on them.

The last thing I'll say is, you know, in guiding that, be as consistent as possible with what the priorities

are and how much time you have available for folks to work on those priorities. Consistency will go a long way in allowing companies and folks like myself to invest time and energy and be available to help you solve those problems.

That's it for me. Thanks for the opportunity to contribute.

MR. ELKIND: Alright. Great. Thank you, Matt. Appreciate your remarks, especially to broaden out this issue to thinking about workforce and equity, really important considerations, and I look forward to hearing more from you in the Q&A.

And with that, let me go back to Karen, who is going to be second and now third. Well, originally, she was going to be third and then second, but anyways, it doesn't matter, but we're happy that you can join us.

So Karen, over to you.

DR. WAYLAND: Yeah. Thank you. I'm actually on the East Coast, and so I had a board meeting right in the middle of this panel, so I appreciate your moving me around and creating confusion for everybody, so appreciate it.

So I want to talk about the kinds of grid investments that we see necessary to support clean energy policy goals. And you've heard a lot about that all day, but I am going to focus more on the kind of technology and other kind of investments that have to be made to,

specifically, to meet -- oh, sorry about that. I double-clicked on my video and you couldn't see me. So I want to talk a little bit about the kinds of investments that have to be made to meet clean energy goals.

So if you could go to the next slide, please?

GridWise Alliance is a member organization of utilities, grid equipment manufacturers, consulting companies, and we have three of the five RTOs as members, as well, including CAISO. So we work on a whole range of issues around grid modernization, both at the federal and the state level.

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One of the new initiatives that we started about a year and a half ago was the technology portfolio initiative. And what we're trying to do here is to take this very complex engineered system and boil it down into one-pagers and into kind of -- to provide some insights to policymakers into what the functions of technologies are that provide services to the grid. And we looked at five functional areas in grid services: integrated planning, system visibility, real-time operation, consumer and energy services, and emerging grid architecture. And these are the organizing principles that we use to look at the investments that have to be made in order for the grid to serve as a platform for policy goals.

Next slide, please.

We have one paper that was introducing the technology portfolio initiative. And you can find that at our gridwise.org website.

But about a year and a half ago, right after we did that technology portfolio paper, we were asked by some senior officials at the Department of Energy, right after the infrastructure bill passed, to look at what were the kind of near-term investments that would need to be made to help set the stage for accelerated transportation electrification?

And so we did a whole series of stakeholder engagement workshops, both with our members and with state and other organizations, and came up with this paper, The Near-Term Grid Investments for Integrating Electric Vehicle Charging Infrastructure. And we looked at the kinds of technologies.

And I will say that when we say grid investments, we're not just talking about technology. We're also talking about kind of human interaction investments that are going to have to be made in order to really make sure that the grid is ready for more electric vehicles. And we know that we're just talking at this point about no-regrets investments that allow us to meet increased load, perhaps time of use charging, but that are setting the stage for

vehicle-to-grid integration, which we hope in the next five to ten years will become much more of the norm with how the grid interacts with electric vehicles.

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So I'm just going to go through a few of the technologies that we know in our report -- or investments, I shouldn't say. They're not just technologies.

The first is we look at what we have to have on the grid to enhance system visibility. And system visibility is really about allowing grid operators to see power flows on the grid, both in the short term for grid operations, but longer term for planning efforts. And this is things like where is electricity coming in and out of the system? Where is it being used? Where is it being generated? How it's flowing both across the distribution and the transmission systems.

And we need that increased visibility so that we -- and it's got to be across the grid, but right up to the grid edge and hopefully on the other side of the meter as well. And we need that with enhanced communication and data sharing systems so that we can manage the grid at granularities that are going to be required with these, you know, intermittent loads that are going to be caused by electric vehicles. We think that this extended real-time situational awareness is going to support EV charging

infrastructure, but it's really going to be much broader across the system in terms of enhancing reliability and power quality.

So a few of the technologies that are going to be critical for that, I'll start with advanced meter infrastructure, which is, you know, as you all know, it's the meter. It's at that interface between the customer and the grid. And it allows the grid operator to understand the customer usage and also to send back to the customer, potentially, time-of-use signals.

But the new advanced meters are really unique. I know that California got a significant amount of money during their Recovery Act in 2009 to invest in AMI across the state. But what we're seeing now is that AMI, you know, the old AMI did produce data, sometimes in 15-minute intervals. But right now the new AMI can provide real-time data, and also provide another service that's going to be very essential to integrating DERs onto the grid, which is voltage monitoring and control. So what we're seeing is that the new AMI are a solution for last-mile power quality.

And I think it's important to note that you may have seen rate cases and investment requests from utilities for AMI in the, you know, recent past, but the new technologies are going to allow for a much different

interaction between the customer and the grid.

The next technology that I want to mention is broadband infrastructure. And utilities have a whole legacy of communication networks across their systems built on top of each other. You know, they're communicating with their equipment, they're communicating with their line workers, they're communicating with their customers. But truly for an integrated grid, we're going to need to replace all of that infrastructure with broadband. And that is internal to the utility, whether it's wireless or fiber, but it has the potential, actually, for the utilities to provide that broadband if they increase capacity to their customers as well for increased high-speed internet access.

So that's going to be a really critical thing for true vehicle-to-grid integration going forward, and for a whole host of other functions that we want out of the grid.

And then finally, another, and I shouldn't say finally but another key technology that will increase system visibility is dynamic line rating. And I talked about this at the bulk power workshop last week, but it also is critical on the distribution system as well. And dynamic line rating allows grid operators to understand in real-time grid conditions, so what's wind, speed, temperature, other critical variables that will allow them

to avoid heat-related equipment failure and thus allow them to increase the overall capacity of the grid and to decrease costs to the consumer.

The next slide, please.

The next category of technologies affect real-time operation. And you know, both at the transmission and distribution level, the grid needs technologies that can automatically act on system data and deliver the increased load that we expect with increasing EV adoption. So, you know, we know that EVs will be a source of two-way power flow on the grid. And we need to have upgrades that happen at the substation level and throughout the system to prepare the grid for that reverse power flow.

And so there are a number of technologies. I talked about some of them with visibility. The ones I'm going to talk about now are really about grid operation. And I have two minutes left. So I'm going to tell you that the report here explains all of these things in detail.

I will note that all of these technologies -- and maybe you can go to the next slide about consumer and energy services and engagement -- and I'll say that here's where we start to get into investments that are not just technology in nature, technological in nature, they're really about investments in how a utility, how a state looks at the interactions that have to happen in order to

integrate distributed energy resources on the distribution system.

We need investments in communication and coordination. That could be systems. It could be increased ways of providing apps and other things to integrate.

But it also is as much about human power. And we heard people talk about workforce. There is a real need to look at the processes that take place and how you make those processes more effective and more coordinated across governing units and service territories.

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And that goes for integrated planning, as well, which is, you know, early and frequent coordination from the customer, from third-party interests, from across the utilities, the state and federal areas, across agencies, both at the state level and the federal level.

When you think about electric vehicle charging infrastructure and the federal investments that are going to be happening, some money is flowing to the departments of transportation. Some money is flowing to the state energy offices. Some money is flowing to other agencies. And how you coordinate across all of those agencies, both at the federal, state, local level, is going to be really critical and will require investments in people as well as

potentially hardware and software. And you look at hosting capacity studies, forecasting, modeling, all of those things require investments.

So next slide.

So my point is, you know, we are focused in on technologies for one specific thing, transportation electrification. But the reality is that we need to make broad investments across the distribution system in order to create the environment to meet our policy goals.

The Tennessee Valley Authority has been working with 153 distribution utilities and has set out kind of a plan for pulling them up through the grid modernization process through a host of different technologies. And I'm happy to answer questions in the future. I just want to note that these are expensive projects that are not about gold plating anymore. We really are talking about the need to have the grid be the platform for meeting the policy goals that the state has.

So with that, I will finish up and look forward to questions.

MR. ELKIND: Great. Thank you so much, Karen.

And I want to take a few minutes here to ask some questions of the three speakers. And then I'll hand it over to see if the Commissioners want to ask any questions and we can go from there.

But, Grace, I'll start with you. So obviously we've talked a bunch about performance-based rate making and you went into some detail about what you've done in Hawaii. I'm just curious, were there any lessons learned in terms of the implementation of performance-based rate making in your experience that you would want to share? And, you know, we think about the pros, but are there potential cons that we should be aware of, you know, in California as we potentially contemplate moving in this direction as well? Just basically a question around lessons learned that you might want to share.

MS. RELF: Sure. Yeah, it's a great question.

Yeah, there are so many lessons we've learned, but I think from my perspective, a really important one is starting to track data early and often. You know, I think when we were trying to set up our performance incentive mechanisms, it was really challenging to get the right data and have any sort of consistent time series to look at performance over time. And that's really important when you're setting a threshold or a benchmark for performance.

So even if you're not totally sure about, you know, which metrics might be best for a performance incentive mechanism going forward or, you know, really where your interests might lie in the near future, just starting to track that data can really be a good starting

place.

And then, you know, another one is just that I think you're never going to get it perfect the right time -- or the first time. And so building in opportunities to revisit your mechanisms and have continuous learning built into the system, I think, is really critical. Some of our PIMs, I don't think, have worked very well. And so we're looking at kind of revisiting the structure and learning from the experiences that we've had so far.

So those are my initial thoughts, but I'm sure there's a million more.

MR. ELKIND: Oh, that's great. Thank you so much, Grace. I appreciate that additional insight.

And Matthew, I wanted to go to you. You talked about working groups as a potential solution coming out of the interconnection process and moving towards that model for energization and even capacity analysis. And I'm just curious if you could go into a little more detail on that, how you -- who you recommend is included in those working groups, and kind of how that process could potentially get started here, if you had any additional details or thoughts on that?

MR. TISDALE: Sure, Ethan. Thank you for the question.

And I'll maybe just take a moment to maybe invite Grace, or I can add on if Grace wants me to, that it was a working group process that led to the PBR framework that is being very successful in speeding up interconnection in Hawaii.

And so what I'm expressing is that a lot of these problems are collaborative in nature. They take folks getting together and kind of hammering out the details together. On the interconnection side, it was first a settlement agreement between utilities and, largely, distributed generation advocates. That was back in the mid-2000s, around 2005, facilitated at that time by now Executive Director Rachel Peterson from the CPUC. And, you know, it takes time with folks working together in a collaborative environment to get to the bottom of some of these things.

On top of that settlement, as one of the presentations we saw in the morning showed, we had five different working groups that worked through a series of issues on interconnection for Rule 21 reform, things like what should the timelines be? That's probably a question we've heard today for energization. What should the study process be? If it's not what we're using now, how could it be different? What is a utility engineer facing as a challenge when they look at that study? What do they need

to know about the resource that they're going to be interconnecting with? They can't know but for spending time with the person who's going to own and operate that resource.

I've just given you a couple flavors, but these are the type of issues that are very difficult to work out in a more traditional state formal regulatory process. Even when we use workshops like this one, which are good, we're really just scratching the surface on the nuts and bolts.

And I'll just take one more second to emphasize what is one of the most useful things that comes out of those working group process is understanding and trust between the utility engineers and their management about what we're trying to do and the folks who are trying to get the folks in the utility to work differently. And that trust and that social capital that gets built between people is really actually what speeds things up in the long run.

MR. ELKIND: Great. Thank you, Matt, for that additional detail. And nice tie-in to the Hawaii experience, as well, so a good kind of proof of concept there.

Karen, you talked about a number of interesting potential pathways and opportunities, vehicle grid

integration, system visibility, enhancing system visibility. It's just sort of two of those. And I'm wondering if you could cite any programs, maybe demonstration programs or jurisdictions, that you think we could really draw from, you know, that might be a learning experience that could potentially scale here in California if it's not based here or, you know, expanding it out if it is based here in California?

DR. WAYLAND: Well, I mean, I think that there are a number of examples in California and along the West Coast, Hawaii, Portland General Electric in, you know, Portland, on the East Coast, National Grid and others. And they're all -- I mean, this is coming at every utility.

And we put together what's called a Grid Modernization Index Readiness Framework which really looks at how utilities can think about being ready for everything that's coming at them. Everybody is trying new things. Co-ops are trying really experimental programs, doing great things with customer engagement in particular, I think.

So I'm happy to go back and look at some interesting examples and provide them for you. But I think it would be hard to hone in on just one because so many utilities are responding to different state policy goals, they're responding to customer demands that may differ across the country, so it's hard to pinpoint any particular

utility that's doing, you know, interesting things.

I like to look at what the Tennessee Valley Authority is doing. They have 153 distribution utilities and they're trying to bring all of them up to some level of grid modernization that allows for kind of a no-regrets investment that can deal with all of the different things that are coming at a distribution utility, both from the changes in the large-scale utility generation and the things that are happening on the customer level.

MR. ELKIND: Great. Thank you, Karen, for that. Yeah, I appreciate the TVA reference in your presentation as well. And it sounds like there's an online resource that could be very useful that you just referenced as well.

Well, I'll ask one more question of all the panelists, and then we'll see if the Commissioners have any questions as well. And this one would just be just to really name what might be your top one or two kind of near term steps that you would like to see, you know, coming out of this process or related processes that you think has the chance to really make the biggest difference in trying to improve the distribution grid and improve especially the clean energy resources that we need to scale up.

So I will throw that out now to whoever wants to raise their hand who's got a burning near-term step.

I see Karen. Go ahead.

DR. WAYLAND: I have a burning near-term step, which is that to really think about equity and to look at all of the utilities across the state of California, the small ones, the utilities serving tribal areas, the big utilities and think about, you know, all the customers in those service footprints and the access to the grid that they have.

And I really worry about, you know, focusing in on big population areas and seeing how, you know, all of the modern, the DERs and then having the grid investments that support those DERs happen in certain places and they may not happen in other places. And I think that we are at a real transition point where we can focus in on equity and make sure that investments are happening and raising all boats, or we can end up in a place where we have, you know, systems that don't have even basics data, and we are talking about, you know, broadband communication level for other places.

So equity for me in terms of access to a modern grid is really critical.

MR. ELKIND: Yeah, I appreciate that, and echoing some of what Matthew brought up, as well, in his comments.

Matthew, Grace, any burning near term steps you want to mention?

So go ahead, Matthew.

MR. TISDALE: I'll follow Grace.

MS. RELF: I guess I just want to say that I think it's important to ensure that the utilities' incentives are aligned with your outcomes. And, you know, we've seen some real progress on interconnection times on DERs because it was a very specific focus of our PBR framework. The utility has significantly streamlined that process because there were financial rewards attached to that. So that would be one step I think you all could take.

And then just, you know, taking advantage of this pool of federal money that's on the table, I think is critical as well.

MR. ELKIND: Great.

Matt?

MR. TISDALE: I would only just add, keep doing what you're doing at the start of this workshop, provide a clear, consistent signal that this is a priority. When you ask questions about these things, it makes us all work on it. We all call one another, say, what should I say? Well, what do you think? What can I learn from you? Keep asking those questions. Keep sending the signal that solving this problem is a priority.

You know, we all have a million competing things on our attention, a million parts of this clean energy

problem that we're trying to solve. If this is a priority, keep saying so clearly and consistently, and it will get solved.

MR. ELKIND: Alright, well, on that note, let me see if Commissioners have any questions.

I see Commissioner Gunda, so you have your hand up, so please take it away.

VICE CHAIR GUNDA: Thank you, Ethan. Thank you so much for moderating that. That's a wonderful panel.

Grace, nice to see you since the NARUC work last year in Hawaii. Thank you so much.

Just at a high level, and I'm going to just go to Matt, but you really kind of hit on an important note that I keep struggling, and I tried to ask the previous panel as well. And I agree with your supposition that workshops are not really the place to solve a lot of these things that we're trying to do, you know, really want to be in a space where we're rolling up our sleeves and working together to solve. So it's a two-part ask of you.

One is -- and if others want to comment on it -- one, how do you make those working groups really representative, that by the time that working group yields a solution, there is broad trust in that solution being viable; right? So that's kind of one.

You know, so that kind of leads into the second

point of, you know, the agencies have certain statutory requirements of what it means to build a record; right? And how do you synchronize to optimize the time, right, when we are leaning on, you know, kind of the working groups that are done outside the state regulatory community? How do you really use that to accelerate the process; right?

So I think I just wanted to frame that question because ultimately, for me, it keeps coming down to this, the fourth largest economy, home to some of the smartest brains in the world, and we have some ambitious goals, and we seem to be moving slower than we want to. And it seems to be coming from, you know, in lack of better words, a lack of agreement on the pathways; right? And every solution seems to be a good solution, but for us to come to a viable solution, it requires understanding of trade-offs, understanding of internalizing the consciousness of -- you know, I think you put it well, Matt, in your topic, if energization is happening ahead of interconnection, what's the point; right?

So how do we really advance public trust in the process while creating this consensus that we can quickly move on some low-hanging fruit? What's the framework?

MR. TISDALE: Thanks for the question, Commissioner. I'd be happy to speak to that. And I know

that Grace has good experience with this on the Hawaii side, as well, so I hope she'll feel motivated to add to it.

First part of the question, how do you make one of these processes, through which folks get to collaborate in a working group environment, representative? Two notes here, maybe three.

One is that you can't just call the working group together and expect it to start work in a month. It will need time to get ready for that, especially people who work for organizations who are trying to advance social equity, who are not as well resourced as, say, for example, an investor-owned utility or, say, for example, a large automobile manufacturer. These organizations need time to rearrange their human and financial resources so that they can be there and present. Three months is a minimum. Six months is ideal.

Second is that if we're asking for folks to bring their expertise, to contribute that expertise into a conversation like this, they should be financially compensated for that. If I'm an attorney representing a utility or if I'm staff at a solar company, I'm compensated for that. If I'm a member of the public, it's not as clear how I get compensated for that; right?

I think we have an ongoing and good conversation

about how intervener compensation works in this context. I think we have ongoing and good conversations about funds that have been allocated through recent legislation to enable these representatives to be at the table and to be financially rewarded for their participation and for their expertise. Amen. Hallelujah. Let's get it done.

The last thing, and this is a little bit biased, is I think that independent facilitation is incredibly important. We usually, in the past, have just asked our utility friends to host the conversation. Our utility friends are good at a lot of things. They are trusted in many things, but independent facilitation goes a long way towards increasing trust in the process.

The second part of your question, and I'm taking too much time, so I'll be very brief, is how do you get all that on the record and how do you create transparency around it? There's lots of mechanisms here. You can task your facilitator with filing reports on the record. You can bring it into the record that way. You can record conversations so that there's plenty of transparency. This is a problem that can be solved through the way you structure the conversation and you report out from it. And we've solved it lots of ways and lots of times.

MR. ELKIND: Great.

I know Commissioner Monahan has a question, but I

want to see if Grace or Karen want to add to anything that Matt just said?

MS. RELF: Very briefly.

I think in terms of building trust, education at the beginning of the process was really critical to our PBR working group. I think having everybody feel like, oh, we're starting from a level playing field of understanding and knowledge was really critical.

And, yeah, I would just echo Matthew. I think independent facilitation is really helpful. You know, our RMI colleagues, and Gridworks in the past, too, has helped us design really thoughtful process for our working groups that have enabled an informal kind of half of our process that led to a more robust and better informed formal part of the proceeding.

MR. ELKIND: Great. Alright.

Well, lastly, we'll go to Commissioner Monahan for a question.

COMMISSIONER MONAHAN: Well, I thought that was interesting, Ethan, because you too are a master facilitator. We have a lot of master facilitators in this group and you run a great process as well.

And Matt, I thought you'd be interested to hear that one of the ideas that's come up is reinvigorating the VTI Working Group, that that was -- yeah, way back. There

you go.

So I wanted to ask Grace a question about PBR. So, you know, you quite focused on DERs as the metric. And we in California, of course, are really trying to expedite transportation electrification, building electrification. Just kind of curious how you landed on DER on that metric and whether -- I mean, one of the challenges is you pick your favorite child, right, and then your favorite child flourishes and all your other children are sad and they don't flourish. And, you know, that's a challenge that we face. We love all of our children and we want to get to 100 percent clean energy futures, so just sort of how you made those choices.

And then one last and then I'm done is around, you know, we also have to make sure it's a safe, affordable, reliable grid and how you balance those other priorities.

There's a lot in there. Sorry.

MS. RELF: Critical questions to be asking.

So the PBR framework or the PBR process kicked off with two years of working group meetings to align on the objectives and outcomes that we wanted to see coming out of this PBR framework. So that was really critical. I know that sounds like a lot of time to invest in sort of just maybe high-level conversations. But by the time we

got to the end of that process, we were able to say, you know, the utility is functioning really well in these areas and the utility is not functioning well in these areas where we have decided that that's a priority outcome.

So from there, we had sort of a clear picture of, you know, a couple of key areas where we were all aligned that this is a clear objective and the existing utility regulation is not necessarily achieving what we want it to achieve in that area. So once we were sort of aligned on there, then the parties came to us with different proposals for mechanisms to meet those objectives. And, you know, we were able to align on a number of them. I think DERs really rose to the top as somewhere where the utility was not necessarily performing to like a national standard or, you know, where their performance needed some additional support.

Some of the ones that the parties felt could use additional incentives, ultimately the Commission ruled not -- we did not adopt performance incentive mechanisms in those areas for one reason or the other. One, you know, sometimes we felt like there wasn't sufficient data to support a well-designed mechanism at this point and so we started that data collection process or, you know, because it was already being addressed by another incentive mechanism, that kind of thing.

So I can just give an example that there was a lot of enthusiasm for an incentive mechanism for electrification of transportation, but we just really didn't feel like we had the right data to be able to set performance thresholds and tie a reward to that at this point.

So that's really where we established metrics to start reporting on that to inform future mechanisms. You know, the choices are hard though. It's not easy.

MR. ELKIND: Great. Thank you, Grace, and Commissioner Monahan, for the question.

Any other questions from the Commissioners?

Well, I think we might just be at time here. I know we got a little late start on the panel. So assuming we have another minute or two, I'll just see if any of the speakers have any concluding thoughts or any final sentiments they want to share advice and I'll give you the floor?

MR. TISDALE: It's been a really long, but excellent workshop. Thank you for pulling it together. And I wish you all a lot of luck in digesting the information that was shared here today. It's a lot. We got a lot to work with.

MR. ELKIND: And Karen, did you want to add something?

DR. WAYLAND: No. I was just going to reiterate, you have, you are leading the way, and so these workshops are -- well, they've been really interesting. Thank you for being able to participate.

MR. ELKIND: Great. Alright. Well, thank you all of the speakers, and I'll hand it back over to our organizers. Thank you all.

MS. RELF: Thank you.

MS. RAITT: Commissioner, this is Heather Raitt and I think we're ready to move on to public comment if that is good for you, if that works?

COMMISSIONER MONAHAN: Yeah, that sounds great.

MS. RAITT: Okay. Okay, so we'll go to public comment.

And I see we have some hands up on Zoom. And so if you did want to make comments, we limit them to three minutes per person and one person per organization, please. And you can press that raise hand function in Zoom to let us know you'd like to make comments. And if you're on the phone, just press star nine. And so when I call on you, we'll open up the line from our end. And if you could please state and spell your name for the record and your affiliation if any.

And so we'll go ahead and get started with Tom Kabat.

Go ahead, Tom.

MR. KABAT: Thank you very much. And thank you for the very informative discussion today.

It appears that so much of the distribution planning is really a matter of being sure that things can be right sized and built in time. And so that dilemma on getting things right sized, you know, not over building too early before the load arrives and not being too late and delaying people makes me see the value of the thing we call panel optimization when out at the real grid edge, out at the device side, in terms of trying to pick the most efficient and right sized devices to meet our end use needs, like the most efficient heat pumps, and then right sizing them so that they don't overburden the distribution grid and they still get our needs met.

The same thing with sizing the EV chargers at the right level. We see examples in some towns where they have a lot of wealth and they install a lot of EV chargers in their homes. And they kind of fall into a form of range anxiety where the electrician sells them the oversized 50 amp circuit EV charger and all their EVs on the same block turn on at the same time each night because they're all the same model brand of EV and they overload the transformers. And it only takes a couple of houses on the block getting those 50 amp circuits that then there's no more pull top

transformer space for the rest of the houses to electrify their cars.

So focusing in on right sized devices and designing the utility programs and incentive programs to pick right sized, very efficient, well controlled devices so that we can meet the needs of everyone electrifying in an orderly manner is probably the way to go.

And so I encourage the Commission to keep moving forward with SB 68 implementation that has the Commission developing the guidance and information to help people electrify more efficiently so they get all their needs met and leave space for their neighbors to electrify and leave workforce space too. Because electrifying efficiently takes fewer electricians and does less panel changeouts and upsizing and service wire connections and pull top replacements by the overstressed utility staff leaving them time to get -- to help everyone efficiently electrify.

So one of the little things we use in the power group is to electrify simply so others may simply electrify. And we're trying to do a study of trying to quantify what are the upstream benefits of using that efficient electrification technique? And to the extent utilities could join into that effort it would be very helpful.

Thanks so much for kicking this off.

MS. RAITT: Thank you Tom.

Next is Claire Broome. Again, if you could spell your name and your affiliation, if any, for the record?

Go ahead, Claire.

MS. BROOME: Good afternoon. Claire Broome, C-L-A-I-R-E B-R-O-O-M-E, representing 350 Bay Area an environmental and ratepayer organization.

So, first, thank you so much for a really stimulating and fascinating series of presentations.

I wanted to hold up two, maybe three if I have the time, conclusions that I took away from the day.

First, I totally second Ms. Relf's urgency in aligning incentives and penalties with meaningful outcomes. And I think we've heard a lot on interconnection delays. Some people said, oh, the utilities need more employees. Others said, no, no, if we utilize third-party electricians that would help. I suggest that if, in fact, there are penalties and incentives for decreasing interconnection delays, utilities will figure that out.

The second point that really grabbed me was Mr. Marks from SMUD when he said that their study of load flexibility and managed charging resulted in savings of half the cost over the projected 20 years. Half the cost, that's pretty impressive, and I don't know exactly how that study was done.

But I suggest that as a ratepayer, and hearing about the wonderful opportunities, keeping load flexibility front and center as a feasible and inexpensive way to get there is really important. Very specifically, I'm really heartened to see the PUC and the CEC together and paying attention to these issues. And I think it's particularly important that they're collaborating on the demand flexibility efforts to get time differentiated dynamic pricing.

I just think it is absolutely crucial that that process optimizes the price signals that are sent by volumetric rates. Please don't lock up that value in fixed charges which penalize conservation, energy efficiency, and minimize the opportunities to realize savings from load shifting and load management.

And then the third point, I loved that Ms. Relf and Mr. Elkind pointed out the essential nature of improved data. I've spent a lot of time trying to figure out what's happening with resources on the distribution grid in front of the meter. We need better data.

Thank you so much.

MS. RAITT: Thank you.

So next we will go to Michael Bergey.

Michael, if you could spell your name and give your affiliation? Go ahead now.

MR. BERGEY: Sorry. Okay. Can you hear me now?

MS. RAITT: Yes.

MR. BERGEY: Thank you for the opportunity. My name is Michael Bergey. I am President of the Distributed Wind Energy Association, and I'm also CEO of Bergey Wind Power Company, which is the largest manufacturer of small wind turbines in the U.S.

I've come today to offer a suggestion related to interconnection that I think would be a way to bring more and more diverse clean energy onto the grid quicker, and that would be to temporarily relax the inverter listing requirements for small wind turbines up to 30 kW, specifically allowing NRTL certification to UL 1741 instead of the Rule 21's current requirement for UL 1741 SB for a period of, say, two years, and ideally also eliminating the unapplicable efficiency test requirement which was set up specifically for photovoltaic inverters.

So what's the problem? Well, first of all, solar inverters are not technically compatible with small wind turbines, so the great number of currently listed inverters is no help to get small wind turbines onto the grid.

Second, the development of smart inverter functionality and the NRTL certification complexity and costs are a real challenge, particularly for small businesses such as mine and some of our other companies in

our industry.

And third, there are certified American-made small wind turbines available, and there is significant California demand for those turbines, but installations are on hold pending inverter certification to SB. That certification may not be available in our industry until 2024.

We think temporarily relaxing interconnection requirements represents an opportunity for several reasons.

First, small wind turbine technology has progressed. Under support from the U.S. Department of Energy, LCOE or payback periods have been reduced by 50 percent. And in windier locations in California, they represent a least cost renewable energy technology at small scale.

Second, with the IRA legislation, there are now robust incentives available from both the federal government and California's SGIP Program and California homeowners and businesses are missing out on them.

Third, recent NREL market studies have shown considerable potential for behind-the-meter wind in California, including in areas designated as disadvantaged.

And fourth and finally, in important small wind areas, the resource peaks in the evening during the summer, helping with ramp rates.

So in summary, we believe that relaxing the inverter certification requirements temporarily for small wind turbines, perhaps via resolution or editing the OSEGT listing pathway, would benefit the clean energy goals of the state and increase consumer choice without sacrificing safety or grid power quality. More clean energy quicker.

Thank you.

MS. RAITT: Thank you very much.

Next is Ali Detrio, and go ahead. You should be able to unmute on your end.

MS. DETRIO: Hello. Can everyone hear me?

MS. RAITT: Yes.

MS. DETRIO: Great. Hi, Ali Detrio with the Microgrid Resources Coalition. I don't know if you need me to spell my name for the record, but I'll do it at the end. Just want to make a couple comments.

First of all, thank you so much to the Energy Commission for the robust discussion today. What a great slate of panelists, great ideas. And the Microgrid Resources Coalition wants to emphasize, we really appreciate all of your work in all of these efforts and interconnection is a big challenge.

One, we really support the idea of implementing performance-based regulation for interconnection and would love to explore more of the PIM ideas for grid services and

other benefits raised by Raquel at Berkeley and I think discussed amongst many other panelists.

We also support any and all efforts to increase utility interconnection resourcing so we get more manpower to process applications in a timely manner and be able to bring in more third-party entities that are qualified as discussed to help with interconnection review and processing so we really expedite the interconnection process. I think we can throw a lot of resources and manpower at this. Yes, it requires coordination, but this is one of the biggest barriers we're experiencing here when it comes to deploying new clean energy capacity on the grid.

A few other things that I wanted to also note is that, you know, strategic decentralization should be a strategy that California undertakes as it looks to modernize its grid for the future. Even if the grid were 100 percent green already today, there were some comments that alluded to that we wouldn't consider things like onsite generation or linear generators if we didn't have this decarbonization challenge. So a few things on that note.

One, the grid isn't 100 percent clean today and so we do need to clean it up.

But two, the centralized utility model is the

cause of many of our wildfires and outages. Transmission is very expensive and is the main cause of ratepayer cost increases according to CPUC's own Affordability Report. And transmission and centralized infrastructure is very vulnerable in the face of climate change, extreme weather, et cetera.

So decentralization is a strategy for climate adaptation, cost reduction, smoothing the pathway to electrification in an affordable manner without undue strain on the grid. And for reliability, we can provide the capacity and deploy it strategically in the areas where it's needed if we have decentralized resources like DERs.

And then the final note on the comments and ideas about using onsite generation to power new customer loads while they wait for interconnection, I think Commissioner Gunda made a comment about exploring onsite generation and sharing power with neighboring customers. This is technically possible and we would love to be able to do this. There are policy barriers preventing this. And if they were solved, we could unlock tremendous energy optimization, grid benefits, reliability, et cetera, and reduce costs for ratepayers.

And the final thing, I know I'm at time, is that if we don't figure out how to solve these barriers and strive to create price signals and incentives for customers

to stay connected to the grid long term and participate in this clean energy transition, we're really going to see more problems down the line. So these policy barriers are really important to solve to meet all of our --

MS. RAITT: Thank you. We need to move on to the next person.

Diego Quevedo, sorry, I mispronounced that, go ahead, state your name for the record and unmute, please.

MR. QUEVEDO: Can you hear me?

MS. RAITT: Yes. Thank you.

MR. QUEVEDO: Excellent. Thank you. Yes, my name is Diego Quevedo, D-I-E-G-O, last name is Q-U-E-V-E-D-O. I'm the utilities lead at Daimler Truck North America. We are the largest commercial vehicle OEM in North America, with about 40 percent market share. We have vehicles from walk-in vans all the way up to your class eight semi tractors on the road. Last year we sold about 187,000 vehicles in North America.

I really commend the CEC for organizing this workshop. It has been very insightful. A lot of common topics which I agree with, especially performance-based framework for utilities to incentivize them to energize customer depots, specifically in time. So I really appreciate all the comments.

And I would just like to highlight for the record

the importance of timing, specifically for California, as it relates to the Advanced Clean Truck Rule and the Advanced Clean Fleet Rule, which come into effect just next year. By our own estimates, just starting next year, California is going to need an additional about 120 megawatts of installed capacity, new installed capacity on the distribution grid to support the ACT Rule.

And I just want to highlight that especially the medium- and heavy-duty vehicle segment, starting from Class 6 vehicles and up, those vehicles cannot rely on AC charging; right? They cannot plug into a standard outlet like a passenger vehicle because it does not make economic sense to charge a vehicle at one to three kilowatts, so they need dedicated DC charging.

So every vehicle that is sold in the commercial segment has to have additional capacity installed on the grid to support that. Now some depots and fleets will be able to add the capacity if they have the head room. But the larger fleets, you know, they're going to be requesting two to five megawatts, and these depots are co-located, especially in the Inland Empire, and so those megawatts of additional capacity add up pretty quick.

So I would just like to emphasize the timing of all the activities that have to happen so that they line up with state regulations that have already passed.

And I would just like to add one more thing to the record, and that is that Daimler Truck is very supportive of this transition to the tune that we've started a joint venture to build out a public charging network for the commercial vehicle segment specifically, so that there's charging sites that can physically fit these commercial vehicles because all public charging today really just supports light-duty passenger cars.

Thank you.

MS. RAITT: Thank you very much.

Next we will go to Bill Boyce.

Bill, you can go ahead and begin.

MR. BOYCE: Thank you. Bill Boyce, B-I-L-L B-O-Y-C-E. I serve as the Secretariat for the West Coast Clean Transit Corridor, which is a collaboration amongst the major west coast utilities to support planning for large-scale medium- and heavy-duty and light-duty goods movement on the major freight and transportation corridors on the west coast.

I have two quick points that I kind of wanted to hammer home.

It was noted today in a lot of the speakers that there was a need for capacity in the major transportation corridors, and some of the new, you know, large-scale medium- and heavy-duty charging plazas are going to be

rather large in size. Francesca Wahl from Tesla had a great chart that showed that those could get as high as 19, 20, and in some of our studies, upwards of 30 megawatts of capacity needed at a single site. That's as much as a small city.

So kind of combining that need with what was talked about last week with regards to the zonal transmission planning, I'm wondering if that type of electrification on the transportation corridors was taken into account in the transportation or the transmission planning map that was shown last week? And it would be great if there's some sort of layering on those zonal maps to maybe show how some of these applications are being looked at with regards to especially transportation at that level.

A second point I wanted to bring up was workforce development. That got brought up a lot today, got brought up a lot last week. There's going to be a lot of need for power engineers across the board. That's a four- or five-year commitment to get people through college on that. Erica from San Diego, I believe, brought up the fact that utility designers even at utility level are a two-year training commitment before they're really competent, really cranking out all the design work that everybody talked about is in need.

So I'm wondering, it hasn't been brought up, but I'm wondering if there's an educational strategy that needs to be considered when we try to actualize all these energy plans? And, you know, getting these people trained up, getting the colleges aligned, how are we going to get all these new engineers to support all the work? You know, it's going to take changes in those systems, too, to crank out the workforce that's going to be required to get all this done.

So that concludes my comments. Thank you.

MS. RAITT: Thank you.

Next is Cole Jermyn. If you could just give your name and affiliation? And you should be able to unmute and go. Thanks.

MR. JERMYN: Yes. Can you hear me?

MS. RAITT: Yes.

MR. JERMYN: Great. Thank you. My name is Cole Jermaine, C-O-L-E J-E-R-M-Y-N, and I'm an attorney with the Environmental Defense Fund. My team focuses on the utility policies needed to accelerate truck and bus electrification, including more efficient interconnection of charging infrastructure and co-located distributed energy resources.

We, as a team, we're already hearing from fleets in California that they're seeing long interconnection

delays as they try to electrify, and that's adding significant costs and headaches to their transition to EVs. So it's encouraging to hear that interconnection issues are a major focus of today's workshop.

I wanted to speak up today to make a point that I think echoes many of the speakers from today's panels, and that is that we'll need a diverse set of solutions to solve interconnection issues, including both in the near term and the long term.

In the near term, it's critical that any interim solutions meant to fill gaps until the grid is ready are themselves zero emissions and contribute to improved air quality in the communities where fleets are located. It's also important that those communities have a voice in the solutions that are being deployed near them, as those people are the ones most impacted by delays or ineffective interconnection of electrifying load, because that just means that fossil fuels continue to be burned for longer and in higher quantities nearby.

With respect to long-term solutions, it's important that the utilities, the CEC, the CPUC, and other stakeholders recognize the lead time that's necessary to serve the significant load that's expected from widespread truck and bus electrification in addition to other end use electrification. They must begin forecasting and

identifying the timing and location of that load now. And hopefully the IEPR process contributes to that moving forward.

And the utilities must begin planning and completing the system upgrade work expeditiously to minimize delays for fleets trying to interconnect so we see those interconnection timelines shortened from the currently long timelines we're seeing today.

I appreciate the opportunity to speak today and heard a lot of encouraging things on the workshops, and we're looking forward to engaging moving forward.

Thank you.

MS. RAITT: Thank you for that.

So I'll just take another moment to ask, if you are wanting to make comments on the Zoom platform, press the raise-hand icon. And if you're on the phone, press star nine to let us know that you'd like to make comments. I'm not seeing any more raised hands. Well, thank you.

Oh, here we have one more from Vincent Wiraatmadja.

MR. WIRAATMADJA: Yeah.

MS. RAITT: Go ahead.

MR. WIRAATMADJA: No worries. Vincent Wiraatmadja. Last name is W-I-R-A-A-T-M, as in Mary, -A-D-J-A, Government Affairs Manager with Schneider

Electric.

I just wanted to also express my thanks to the Commissioners and staff for an excellent workshop, as well as all the speakers. I thought it was highly informative.

On behalf of Schneider, I just wanted to express support, as well, for performance-based regulation. We think that that is a great way to modernize the grid and enable the transition to a truly interconnected future with our EVs as well as our DERs.

I also just wanted to uplift the notion that as we work to deploy IIJA and IRA funds, we should make sure that they are being put into assets that are digitized so that we actually build a grid for the future rather than old school hardware that is predominantly analog. And that will also tie into the performance-based regulation because, ultimately, if you can see it through your digital tools, you can then measure it and then you can then base metrics and performance on it.

So those are my comments. Thank you so much for the opportunity to speak up.

MS. RAITT: Thank you.

Next we have Kathy.

Please go ahead, Kathy.

MR. MORGAN: Actually, my name is Wayne Morgan.

MS. RAITT: Oh. Okay.

MR. MORGAN: M-O-R-G-A-N. I didn't take the time to change my name. And I'm with a number of environmental groups, including the Climate Reality Project and the League of Women Voters.

I was just wondering, has consideration been done with regards to maybe supplying some of these EV recharge stations with DC transmission lines? I understand that transformers are in short supply now and have long lead times. I'm just wondering if that has been considered to interconnect some of these stations with these DC lines instead of AC?

Thank you.

MS. RAITT: Thank you. Appreciate that.

Next is Lorenzo Kristov. Unmute.

MR. KRISTOV: Unmute. Yes.

MS. RAITT: There you go.

MR. KRISTOV: Yes. Thanks. I wanted to just pick up on a theme that was mentioned by one of the previous public commenters that I fear has not really been given enough attention, which is the notion that if we, through policy and regulation, don't create an environment on distribution that is really rewarding to the capabilities of distributed resources, makes it simpler for them to interconnect, accounts for them correctly in planning, and essentially recognizes their importance to

contribute to decarbonization and resilience and equity, but instead let the barriers continue and place financial barriers to distributed resources or don't allow them to get rewards for performing to their maximum.

Then what we'll see, and I think we heard this in especially the panel after lunch, is that parties that can afford the investment will take matters into their own hands, either for power quality reasons or for time delays or because they have higher environmental goals or because of what their customers need. We'll see commercial and industrial customers, residential, more affluent residential customers, adopting distributed resources to meet their need, but if they don't have a context of a network in which they can participate, then those DERs will just be used for the private benefits that they provide to those customers rather than the benefits they can give to the grid as a whole and to the greater societal goals of decarbonization and energy justice.

And we could see then the march of technologies, distributed technologies, actually worsening the equity situation in California simply because the barriers are ones that don't keep out the parties with deep pockets, really, who see the driving needs but do keep out the people that are more challenged financially to adopt them.

So I think this concern about grid defection and

parties taking matters into their own hands when the barriers continue needs to be taken very seriously and built into how we design a distribution network environment that really embraces the growth of distributed resources and enables them to perform, to capture, and be compensated for the true value that they can provide.

Thank you. This is a really excellent workshop today. I really appreciate the efforts that everyone put into it. Thank you.

MS. RAITT: Thank you.

Next is Daniel Drazan.

Go ahead. You need to unmute on your line.

MR. DRAZAN: Yes. Hi, this is Daniel Drazen with Enchanted Rock. I'm an energy advisor. I just want to make a few comments.

First, I want to thank the Commission for an awesome, fantastic, very informative panel discussion and workshop here today.

I also just wanted to pick up on a few things, the first one being the suggestion by Commissioner Gunda that we consider or that the Commissioner and others consider onsite backup generation. As was perhaps stated by some other parties earlier, this is a very important technology and resource that can provide very important resiliency, especially in the context of fleet support and

resiliency. As we move toward trying to electrify fleets, the ever important program to address health concerns and energy efficiency and the like, there's always the concern though that, you know, as was noted that, there may be grid resiliency issues, power grid outages, and that we all want our packages delivered on time, nevertheless.

So I would just recommend the Commission further explore the recommendation that it's heard here today to try to find ways where DERs can provide that grid resiliency for EV fleets in that context.

I just might add that while it was noted by one of the panels earlier about the role that linear technology provides in supporting and providing backup generation and resiliency, linear technology is clearly not the only technology that is out there. There are many other proven technologies that involve clean burning, reciprocating engines involving RNG and the like. So I just wanted to highlight for the Commission, that technologies other than linear exists as well.

But yeah, a fantastic workshop and want to thank the Commission for putting it on. Thank you.

MS. RAITT: Thank you.

So just one more moment to let people press the raise-hand function if you'd like to make a comment or press star nine if you're on the phone. We'll just give it

another second here.

And I will just say that we also welcome written comments and those are due on May 23rd.

And thank you so much for everybody who stayed on and made those thoughtful comments.

I think we will close the public comment, I don't see any more raise hands, and I will turn it back to Commissioner Monahan. Thank you.

COMMISSIONER MONAHAN: Well, thanks, Heather.

And thanks to everybody who participated today. It has been a long day. And we strategically, actually, made that choice because we wanted to get as many Commissioners from across both agencies as we could. And it was really nice having cross-agency representation.

So I just want to thank my colleagues at the Public Utilities Commission and here at the Energy Commission for really putting in the time. I hope everybody is doing something stimulating with your body tonight because we all need to get up after the Zoom call.

So I really want to thank, actually, Heather and her team, and Ben Wender, my advisor, Vice Chair Gunda's team, who was really -- and the CPUC, who has also been involved. There are a lot of cooks in this kitchen planning this series of workshops.

So now I just will encourage everybody, as

Heather said, please submit your ideas into the docket.

There are other workshops that are going to intersect, but these two kind of foundational ones on the bulk grid and the distribution grid are going to be kind of pulling the platform for the recommendations and the observations that we're going to make on how do we speak to deployment of clean energy resources on the grid, recognizing all the amazing work that is going on right now.

I thought today was really great in terms of I think David Erne and Simon Baker from the PUC really helped set the stage about here's what's going on. I'm particularly excited about the freight infrastructure planning framework, which will, I think, help us help move the ball when it comes to planning for freight electrification.

And we heard from Chris Walker this morning with GRID Alternatives about how important it is to make sure that we're prioritizing lower-income and disadvantaged communities and families whose housing is going to be older, it's going to cost a little more to do the work. We're going to have to put more elbow grease into making sure that this is a transition that works for everybody.

We heard a lot of great ideas today. I'm not going to mention all of them. I'll just say a few.

In terms of the importance of transparency, that we need to make processes transparent, understand where the roadblocks are, and capitalize on this opportunity for collaboration to work kind of intently with different interests on specific problem solving. That's how performance-based regulation got developed in Hawaii and I think there's a lot of we've done this in the past in California. We're going to continue to do this, making sure we engage different stakeholders.

We also heard comments about incenting generation and storage to avoid and maybe for delay, costly grid upgrades. A lot of good food for thought there.

And I want to say one thing that Diego from Daimler, I believe it was, talked about, the importance of these, you know, these carbon regulations that are coming down the pipe. I want to say to everybody, I mean, that actually was part of my incentive for wanting to take on this topic is that we know we need to electrify transportation rapidly. It's critical for air quality. It's critical for our climate. We need to do it in a way that's really attentive to rate payers and to safety and resilience.

So that's, you know, that's the reason why you see both agencies and CAISO last week participating in this. We know that this is critical and we are we are

working on it and we're going to continue to work on it.

So if anybody else wants to make a closing comment, just -- Vice Chair Gunda?

VICE CHAIR GUNDA: Yeah. Thank you, Commissioner Monahan. Thank you. I just wanted to, you know, just elevate, you know, the thank you to you. What an amazing couple of workshops we've had, I think, and it just really set the stage for much broader engagement on some critical issues. I think this is this is really well done. Just wanted to thank you for your leadership and all the panelists and people who stuck with us the whole day. We almost have a hundred people still listening in. We were at 200, so it's just wonderful conversation just points to the interest and thoughtful comments, so look forward to collaborating.

I think I want to just, for us, as we think through the IEPR, really also elevating you know to the points that you just made, how do we think about the net benefit, right, net benefit of ensuring electrification happening and, you know, really maximizing demand flexibility to take advantage of the ability of us to energize on the grid side, right, on both sides and really think and, you know, have that guide of, you know, net impact and maximizing the net impact in the short term as we move forward so that we don't lose ground on the big

anchor projects we can do right now that otherwise might be just set aside?

So just wanted to think about how to frame that, the idea. Thank you.

COMMISSIONER MONAHAN: Yes, President Reynolds?

PRESIDENT REYNOLDS: Thanks, Commissioner Monahan. I also wanted to thank you, and also Vice Chair Gunda and Commissioner McAllister as our hosts, and for including the CPUC Commissioners in these workshops. We are really pleased to be working together on these difficult issues.

And also, I think, you know, just having us here today, I wanted to let everyone know that all that also reflects a lot of staff collaboration between CPUC staff and CEC staff, and also CAISO staff, and I really look forward to that continued collaboration. I think it's really important especially on this issue.

I appreciated hearing from all of the panels today and the public comment. And I think, you know, hearing a lot about the challenges and the difficulty of the challenges, the fact we need a diverse set of solutions was really important to you know continue this dialogue and so I look forward to continuing to work together on it.

Thank you.

COMMISSIONER MONAHAN: Alright, I don't see any

other Commissioners raising their hands, so I think we are adjourned. Alright, everybody, go have a lovely evening. Thanks for joining us today.

(The workshop adjourned at 5:02 p.m.)

CERTIFICATE OF REPORTER

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 14th day of August, 2023.

MARTHA L. NELSON, CERT**367

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

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I certify that the foregoing is a correct transcript, to the best of my ability, from the electronic sound recording of the proceedings in the above-entitled matter.

MARTHA L. NELSON, CERT**367

August 14, 2023