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STATE OF CALIFORNIA

CALIFORNIA ENERGY COMMISSION

In the matter of:

2025 Integrated Energy Policy Report (2025 IEPR)	Docket No. 25-IEPR-06
RE: Accelerating Interconnection And Energization	

IEPR COMMISSIONER WORKSHOP ON

ACCELERATING INTERCONNECTION AND ENERGIZATION

REMOTE VIA ZOOM

MONDAY, AUGUST 11, 2025

1:00 P.M.

Reported by:

Martha Nelson

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P R O C E D I N G S

1:00 p.m.

TUESDAY, AUGUST 11, 2025

MS. NAKAGAWA: Alrighty, thank you so much for joining. Today, we're holding an Integrated Energy Policy Report, or IEPR, Commissioner Workshop on Accelerating Interconnection and Energization. I'm Sandra Nakagawa, Director of the IEPR at the California Energy Commission.

This workshop is being held as part of the CEC's proceeding on the 2025 IEPR. Today, we are doing a remote workshop using Zoom. This workshop is being recorded, and you'll be able to find a link to the recording on the CEC website shortly after the workshop. To follow along, you can find the slide decks and a schedule that have been docketed and posted on the CEC's website.

You'll also have the opportunity to ask questions of the presenters and panelists. After each of the panels, we'll have an opportunity for audience questions using the Zoom Q&A, but please be advised we may not have time to answer all questions submitted. Again, you'll use that Zoom Q&A feature if you want to submit a question. You can also take a look at what's already been submitted and upload any that you would like to see answered by clicking on the thumbs up icon. Questions that receive the most uploads are moved to the top of the queue.

Attendees also have the option to make public comment at the end of today's workshop. We won't be able to respond to the public comments today, and those are limited to a maximum of three minutes per person, with one person allowed to comment per organization. Written comments are also welcome, and instructions on how to provide those can be found in the workshop notice. The deadline for written comments is 5:00 p.m. on August 25th.

We're now going to go over to Vice Chair Siva Gunda for opening remarks from the dais.

VICE CHAIR GUNDA: Good afternoon, everybody. Thank you, Sandra, so much for getting started today. Welcome, everyone, to the IEPR workshop on Accelerating Interconnection and Analyzation.

My name is Siva Gunda, one of the five Commissioners here at the CEC, and I'm currently serving as the Associate Commissioner on the IEPR this year, and also support our work on transmission resource planning and demand forecasting. I have been pretty well engaged with the work on DERs, as well, so, you know, just kind of giving a wholistic view of the energy system that we are working on.

I want to thank Commissioner McAllister for being today on the dais with me, and all the panelists, both from CPUC and CAISO, for supporting today's work, and the teams at CEC.

I just want to start with some -- you know, just start with some gratitude to Hannah Griggs, CCST Fellow from the Chair's Office, who has put a lot of work into coordinating this workshop. Thank you, Hannah.

I also want to thank Sandra, the IEPR leadership, as well as Sean Simon and Shannon O'Rourke from our STEP Division, or the Siting Division.

Workshops like this, as I always say, are really critical to provide a forum for problem solving, laying out issues that we need to be thinking through, ideating the problem, ideating some solutions, and get some public input as we move towards more into the regulatory structures.

Today, this work that we're working on is truly to accelerate the transition needed to achieve our climate and clean energy goals. As many of you who are attending today recognize that in both for reliability as well as long-term transition to clean energy goals, the state has to continually build a significant amount of resources every year. And it's really important for us to both connect the resources needed, but at the same time, support electrification on the demand side.

So building on CEC's recommendations in the 2023 IEPR where we've discussed much of these issues as a good starting point, and I want to thank former Commissioner

Patty Monahan for leading that IEPR. We're going to have Hannah describe some of those recommendations, and we're going to move into work prepared by energy assessments division that will be presented by Sean, and then finally go into interconnection queue challenges presented by CAISO and LADWP.

I'm really looking forward to hearing the lessons that we've learned over the last few years, the improvements to the interconnection and permitting processes, and some of the plans to continue to tackle issues and challenges. I think between CAISO and LADWP, we'll have some instructive comparisons between different balancing authorities in California, and also thinking through how to do the distribution energization and planning improvements.

Thanks again to everybody who always take time to join these workshops and provide your input to the state process.

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

CO0MMISSIONER MCALLISTER: Sorry, having a double-mute problem there. Thanks, Vice Chair. You gave a great introduction, and we have a lot of people to listen to and hear from today, so I'll be very brief.

You know, we need it all. We need demand side, and we need all scales on the front of the meter side, and so local, regional, and the largest projects, and including, you know, west-wide, which is the other conversation happening right now.

So really happy to be having this conversation about how we can sort of thread the needle and balance process, but also rapidity, the speed we need to get resources interconnected of all types. You know, diversity is one of our strengths. And in a big, complicated state like California, with lots of knowledgeable stakeholders, and also just lots of resources, and climate zones, and different aspects of demand, et cetera, and balancing authorities, and big utilities of all ownership models. It’s really great to have this platform to do some level setting and make sure we’re all operating from kind of the same, or at least share perspectives and operating from sort of the same knowledge set.

So that’s what the IEPR is for, and really appreciate Sandra and the whole team getting us together, as well as our colleagues at the PUC, and the CAISO, and DWP, all the utilities who are going to present today, and also all the industry. We have some great voices here, a lot of knowledge on deck today.

So really appreciate your leadership, Vice Chair. Would echo the sentiments regarding former Commissioner

Monahan, who’s really leaned in on this in the IEPR a couple years ago.

So, finally, just thanks to, you’ve said it, but I’ll reiterate Hannah, and Sean, and Shannon for all their work setting us up for success here.

So thanks for everybody who’s in attendance. It’s really an important conversation, and all the folks on the dais, as well, really appreciate all the sharing and collaboration amongst the agencies.

So, with that, I will pass it back to you, Vice Chair. Thanks.

VICE CHAIR GUNDA: Thank you, Commissioner McAllister.

In our tradition, just want to note that we don’t have PUC Commissioners today, so this workshop is all ours. With that, I’ll pass it to Hannah.

MS. GRIGGS: All right. All right, well, thank you, Vice Chair Gunda and Commissioner McAllister, for your introduction and your remarks. I also want to reiterate that the work of the team here to put this workshop together was immense, and I want to thank Shannon, and Sean, and Tom Flynn, and Liz, and everybody who was involved.

So, again, I’m Hannah Griggs. I’m a Science Fellow in Chair Hochschild’s office here at the CEC, and

I’m going to give a brief overview of the workshop today and do some scene setting for what our presenters today will be covering.

Next slide, please.

Today, the workshop will be divided into two sets of panels, the first covering the topics of interconnection and energization at the bulk transmission system level, and the second at the distribution system level, and then we’ll follow with public comment and closing.

Next slide, please.

So the workshop is being held in partial fulfillment of the requirements of AB 1373, which was passed in 2023 and requires the Commission to assess the barriers to electricity interconnection and energization and provide recommendations on how to accelerate these processes.

I’ll talk a little bit later about this in the presentation, but the Commission has done previous work in 2023 towards the goal of this bill in our 2023 IEPR, and that addressed the same topics that same year that the legislation was passed. So in many ways, the 2025 effort will build off of that previous work.

Next slide, please.

So the legislation is one reason that we’re here today, but why should we be focusing on the barriers to accelerating interconnection and energization?

Well, California is a state with ambitious energy goals. For one, California is looking to move toward electrification. The state aims to see 6 million heat pumps installed and 1 million public electric vehicle chargers by the year 2030. California is also working toward 100 percent renewable energy by 2045.

All of these goals will require an unprecedented scale-up of clean energy infrastructure and will require the ability to interconnect a lot of new renewable power projects, as well as energize a state moving toward electrification. So in order to achieve this scale-up, it has to be possible to interconnect and energize more quickly than what's been possible previously.

So one of the motivations for studying interconnection and energization in 2023 was to understand the conditions leading to, in some cases, multi-year wait times to interconnect or energize projects in the state. So if prolonged delays were to continue as California gears up to achieve 100 percent clean energy by 2045, it would be a serious obstacle, so getting our interconnection and energization processes right is key to California achieving its energy goals.

Next slide, please.

Before moving forward, it may be useful to reiterate what we mean by interconnection and energization in the context of this workshop. Interconnection refers to the connection of generating and storage resources that provide electricity to the grid. Energization is the connection of loads, many customer-owned, to the distribution grid. So both of these are crucial as we move toward our clean energy goals as a state.

Next slide, please.

So AB 1373 directs the CEC to study interconnection and energization, but it’s also useful to look at the levels of grid systems these processes happen in. So this workshop, instead of focusing on interconnection and energization in two separate panels will actually be structured to look at interconnection and energization in the context of the bulk transmission system and the distribution system, which make up California’s electric grid.

Next slide, please.

So the first set of panels will cover the bulk transmission system, which is made up of high-voltage lines carrying power over long distances. The transmission system is the site of interconnection for utility-scale generating and storage resources.

And then, afterwards, the workshop will turn to the lower-voltage distribution system, which connects customers and their behind-the-meter loads to the grid. There are interconnection and energization examples in the distribution system, including interconnection of residential solar, which can provide power back to the grid, and the energization of EV chargers.

Next slide, please.

So as Vice Chair mentioned earlier, the CEC tackled these topics previously and not too long ago. In 2023, the CEC looked at the barriers to accelerating the deployment of clean energy in its 2023 IEPR as one of its Commissioner-selected topics. So here I'll briefly review what that report discussed to set the scene for today's discussion.

Next slide, please.

The 2023 Report was structured around the key issues that the CEC saw as barriers to accelerating interconnection and energization at the time. It really distilled things down to five categories of considerations that the CEC identified as crucial to keep in mind as the state moves to address barriers.

So the first and the most emblematic of the state's issues was to prioritize reducing the timeline to deployment for clean energy resources. The report noted that some projects were experiencing multi-year delays, which is a chief concern when the state looks to scale up its electric infrastructure to support a fully renewable and electrified economy. One of the areas of opportunity when it comes to prolonged timelines in 2023 was improving the state’s resource procurement and transmission planning processes.

Another consideration for quickly scaling up electric infrastructure is the effect that such a project would have on ratepayers.

The report also highlighted data and process transparency as a key sticking point for why the interconnection and electrification of projects, why those delays were so common.

And finally, the report noted that permitting reform may be a key avenue for reducing project delays.

Next slide, please.

The report in 2023 identified, also, some recommendations, some specific recommendations to address the barriers to acceleration, which we’ll hear a lot more about in our panels today.

But to give a brief overview, the recommendations of 2023 included emphasizing the importance of interagency collaboration to solve these problems. And that includes through an MOU, which will be featured a lot in the panels today.

It also recommended exploring proactive

investment into grid improvements through improved planning processes.

It also highlighted data transparency as a key part of the state's improved processes.

And finally, the report emphasized the needs to manage the cost impacts of grid improvements to ratepayers through innovative or creative funding solutions.

So the 2023 IEPR did a lot to explore the issues in California leading to long clean energy project timelines, and it highlighted some potential solutions that the state's been working on since 2023.

Next slide, please.

And that brings us to today. So looking forward in the 2025 IEPR, this workshop aims to report on the state's progress since 2023 on accelerating interconnection and energization timelines, as well as to discuss ongoing initiatives statewide to address these barriers going forward.

Next slide, please.

Okay, so with that, I'll thank you all so much for your time and attention. We've got some amazing presenters today, so let's jump right into it.

I want to introduce Sean Simon, who's the Acting Director of the Siting Transmission and Environmental Protection Division at the CEC to start off our first panel on bulk grid interconnection.

MR. SIMON: Thank you, Hannah. Everybody hear me and see me okay? Great.

Okay. Hi. So my name is Sean Simon. Thanks for the introduction, Hannah.

And we can actually go right to the next slide, please.

So while the main focus of today’s workshop is on interconnection and energization, this doesn’t exist in a vacuum. It’s really in part of a broader ecosystem of activities focused on bringing resources online when and where we need them. And there’s been extensive work across the energy agencies, the California Independent System Operator, the Cal ISO, IOUs, and publicly owned utilities and developers to strategically shift the transmission development process to address these barriers.

So in this panel, we have representatives from the entities that are part of the Joint Transmission MOU to provide updates on the range of transmission planning and permitting activities that have been advanced since 2023 to help bring resources online and really what lies ahead. And then the next panel will focus on interconnection specifically as there has been a lot happening there, as well, and some more to do.

The Energy Commission has broad statewide perspective and the state’s energy infrastructure planning activities are really geared towards attaining our climate goals while maintaining reliability and managing costs. My MOU colleagues will cover the MOU in much more detail, but just at the highest level in terms of responsibility, the CEC forecasts long-term electricity demand, incorporating the state’s goals for 100 percent clean electricity and economy-wide GHG emission reductions. And that demand forecast informs the PEC’s integrated resource planning process, which in turn informs the ISO’s transmission planning.

But in practice, the MOU goes much further. Our staff coordinate on all aspects of the resource and transmission development to assure policy is executed well, as well as process changes, all the way to revamping reporting activities and then engagement with the energy resource community in various venues.

One is the Tracking Energy Development Task Force, the TED Task Force, which is led by the Governor’s Office of Business and Economic Development. It’s a new concept over a couple of years, but it’s a good example of how we’re continually thinking about how to improve processes to then get to better outcomes down the line.

So as you’ll hear, there’s been significant process made in reform since 2023. Not all of the fruits are borne out yet from these reforms, but today's discussion can help create that shared understanding of what progress has been made and where the state needs to continue to focus in looking ahead. And, you know, today's focus will be on the ISO territory, which is, you know, roughly 80 percent of the state. It's really important to highlight the role of the publicly owned utilities as state partners in ensuring infrastructure across the board is available where and when we need it.

We can go to the next slide, please.

So as Hannah covered, California has brought on an unprecedented amount of new clean energy and storage resources to meet our climate and reliability goals and to keep pace with increasing electrification and other sectors. Successful policy technological developments and economic shifts are driving increases in electric load after a long period of relatively flat demand. This rapid growth of resource development put pressure on the existing interconnection processes and were very front and center at the time of the 2023 IEPR, as Hannah covered.

And these increases in the interconnection queue and needs for transmission with increased costs affected the complexity related to network upgrades and kind of across the board. My MOU colleagues will go into this in more detail, but this image is one of many that really amplifies the message that managing the increased pace and scale has required and will continue to require coordinated and strategic approaches.

Next slide, please. Thank you.

So before handing it off, I just wanted to touch on some maybe less visible activities that the Energy Commission has been leaning into since 2023.

The first, you know, we, really, we think broad in California, we think big and bold. And the MOU parties and the Energy Commission are really participating wherever these conversations are happening.

And the first two on the right are really collaborative west-wide discussions that were happening. The first on the cost allocation piece of transmission development from a regional perspective, which has been a tough nut to crack and thought to be one area that can ease development going forward, and then the second bullet is really looking at regional planning with what would that look like to meet the needs of individual states.

And then on the federal side, the Energy Commission participated in the proceedings that were being led both on long-term planning, as well as permitting, which Hannah touched on being such a sticking point in building at a quicker pace than we’ve done in the past. And then knowing that we need to do more and manage the costs, you know, we have participated in some of the federal funding activities and, you know, those are still playing out. But that's an important -- there's no question the federal government can be an important partner in all of this.

So with that, I'm very happy to hand it off to Molly Sterkel at the PUC's Interim Director of the Office of Electric Supply Planning and Costs.

MS. STERKEL: Hi. Good afternoon, everybody. Thank you very much for hosting this workshop today. It is always a little bit of work to get ready for a presentation, but it's also a moment to reflect on all of the activities that we have been able to undertake and kind of synthesize our progress to date.

Next slide. Thanks.

I'm just going to mention, before I head into my handful of slides here, that the CPUC wears a few different hats, so with respect to interconnection. So we have an interest in planning, of course, for the bulk grid. We also have an interest in interconnection tariffs themselves. Of course, we also are interested in procurement of new resources. We play a role in permitting, especially of transmission lines, and we also play a role at the Federal Energy Regulatory Commission in terms of advocating for affordability and ratepayer protections at FERC, so we also play a ratepayer advocacy role.

So we wear a number of different hats, so this is a brief presentation that covers a number of different roles that we play. My slides are going to touch on the themes that Hannah mentioned, both the coordination that we're doing, already introduced by Sean. I'm going to touch on the themes of data and data transparency. And I'm also going to touch on a theme of ratepayer impact.

So let's, without further ado, let's switch to the next slide.

So I'm going to talk about a few of the things that we've been doing specifically with respect to interconnection, but I also want to ground us in where we are today.

Where we are is that we are at a point where we have seen record-breaking new resource additions in California in the past five years. This is an incredible accomplishment that has taken intense coordination across the development landscape. So developers proposed these projects, going back, some of them, well over a decade ago. They worked diligently to permit the projects with state, local, and federal authorities. They worked tirelessly to market their projects, and load-serving entities procured the projects, contracted for those projects. The projects were then sent into the supply chain and constructed, and once the projects were constructed, they had to safely interconnect to the grid.

I think I may have omitted, they also needed to be studied for interconnection, and in many cases, interconnection network upgrades, both project-specific as well as grid-wide upgrades, were built to support these projects. So it is a very complex undertaking.

Having said that, we've brought 25,000-plus nameplate new resources onto the grid as -- with the CAISO as the first point of interconnection. An additional 2,000 megawatts of dedicated imports have been brought onto the grid. There have been over 400 individual new projects that have achieved CAISO interconnection. These are 400 individual resource IDs that are now bidding into the CAISO market and providing energy services to the grid.

These new resources provide over 18,000 megawatts of net qualifying capacity to serve reliability because, of course, not all of these nameplate resources are available every day, all day. And an important note, as you can see from the giant purple swath on this chart, is that over 200 of the new projects are storage. Those storage projects are providing about 69 percent of the reliability capacity, although you can see that they are not 69 percent of the chart.

So even just in 2025, we’ve had over 50 new projects achieve commercialization, come online, reach COD. That’s over 2,800 megawatts so far this year.

2024 was the largest addition of clean energy capacity in the history of California, with just about 7,000 megawatts connected to the CAISO and additionally, you know, additional megawatts outside of the CAISO. I believe we are now at the point where we can say we have achieved over 67 percent clean energy on the California grid, and there was a recent press release about that.

All of that is amazing news, and we should all celebrate it. The remainder of this presentation and the workshop today will be about how hard it is to continue this trend, how hard it is to get here, all of the pain and agony that is represented in these numbers. And I think it’s important for us to talk about those challenges and always work to improve them, but I do want to start us with this piece of happy news.

Okay, next slide.

I always have to start with good news. Okay, so the CPUC, CEC, and CAISO signed a Memorandum of Understanding in December 2022. This was an update to a long-standing Memorandum of Understanding that had gone back for more than a decade. It commits the three organizations to work together on all things related to procurement and resource planning. I'm going to let my colleague Neil Millar talk about the CAISO side of the equation. And I appreciate the fact that Sean already mentioned the CEC forecast related to electricity demand. It was nice to see that load forecast from Sean, because when you looked at it, it showed this inflection point, and it looks like that inflection point is just about where we are today. Right about in 2025, you suddenly see demand start to grow, and that is likely the case.

However, I do want to highlight that the CEC has been forecasting load growth for some time, and the CPUC side of the MOU has been planning for those future resources, and that's why you've seen some of the megawatts that I mentioned in the prior slide coming online, because we are anticipating some amount of load growth and also providing for some amount of retirements.

So the main thing that the CPUC does for our portion of responsibility within the MOU is that we identify the future resource mix through our integrated resource planning process. We develop a portfolio of expected resources, wind and solar and storage and offshore wind and out-of-state wind, geothermal, natural gas, what have you. We look at where those resources are likely to be developed.

We take into account where those serving entities have expressed an interest in developing resources, we take a look at where developers have entered the queue, and we put together two portfolios. One is usually a reliability and policy-driven base case that the CAISO uses in their transmission planning process, and we also look at a policy-driven sensitivity to ask ourselves some what-if questions. Those portfolios feed into the transmission planning process and we -- and then the CAISO authorizes transmission as a result of those portfolios.

In addition, we also work with our load-serving entities, and we ask them where they have contracted for resources. We also have, in the past six years, established a number of CPUC planning orders for resource procurement. And those resource procurement orders have resulted in the procurement that you saw the prior slide, as well as the expectation of probably more than 20 gigawatts of additional resources that are under contract for load-serving entities today.

So this is all I’m going to say about the MOU, but I know Neil will cover it more.

Next slide.

So the second major topic I wanted to touch on today is something that we’ve done recently to improve the permitting for transmission. As I just mentioned, transmission is an important part of interconnection. When there are network transmission upgrades needed, it can provide for the additional interconnection of new resources onto the grid. We also need transmission just to maintain reliability and things like that, but in particular to allow for the interconnection of generation. That's what we're focused on here today.

The CPUC has a general order, which we refer to as General Order 131. We updated it in January 2025. It's no longer called GO 131-D. It is now called GO 131-E because we have a very complex numbering system, naming convention -- I'm joking -- where we go through the letters of the alphabet when we do an update. So this is the general order that establishes our agency's roles for permitting. So an electric transmission company wants to apply for a permit to build a large transmission facility in the state, and they have to come to the CPUC and ask for a permit. The general order establishes the rules of the game. This general order had not been updated in over 20 years, and it was time for a refresh.

These new rules are expected to accelerate transmission permitting timelines. An important reason why it will do that is because this permit -- this general order establishes the interaction between the permitting process and the environmental review process. So the state -- sorry.

So as most of you probably are aware, the state has the CEQA law, the California Environmental Quality Act, which requires state and local governments, including, of course, the CPUC, to inform decision-makers and the public about the potential environmental impacts of any proposed project, as well as minimize the environmental impacts of that project. So since the CPUC needs to issue permits for transmission lines, we have to disclose to the public the environmental impacts. We are the lead agency under CEQA for many transmission projects. And so this general order updates many of the detailed rules related to that.

And one of the key things noted here on the slide is it includes shifting the environmental review earlier in the process and also eliminating some permitting requirements for smaller projects. It allows for applicant-prepared administrative draft versions of CEQA documents, and it clarifies many of the permit exemptions.

It also establishes a pilot program to investigate ways to accelerate the existing timelines for our CEQA review. We have an upcoming workshop on August 21st to cover proposed metrics to be tracked in the pilot program, so I invite all of you to join for that. And we will report results of the pilot program every two years, starting at the end of next year.

Moving now to another aspect of the CPUC's involvement with interconnection and transmission, I want to highlight the CPUC's transmission project review process. The CPUC is the California state agency that represents California ratepayer interests in Federal Energy Regulatory Commission transmission owner rate cases.

And since 2020, California's transmission stakeholder processes and our involvement in the review of transmission have yielded over $1 billion in long-term ratepayer savings. What that means is that the CPUC has participated as intervenors in the FERC regulatory cases that establish the rates for the transmission owners, and we have advocated for reductions in rates.

The only way you can do that is if you literally dig into the details of all of these rate case filings. These filings are analogous to what we do in our general rate cases at the CPUC for distribution-level investments for the investor-owned utilities, but these are the rate cases that take place at FERC.

So under a resolution that we refer to as E-5252, we established something called the transmission project review process. It's a single unified transmission stakeholder process for the three investor-owned utilities under the CPUC authority. And what it does is it requires our investor-owned utilities to file twice per year and provide significant quantities of data on all of the transmission projects that are under development in their purview.

So these projects, transmission projects, take a very long time to go from planning to authorization through construction and commissioning. It is not unusual for them to take more than a decade to go through that process. And so all along that process, the transmission project review process allows us to monitor cost and progress and timelines for those projects.

And so there are these three data requests -- there are these two data request periods for each of the utilities, and each of them has an associated comment period and question period, and that allows stakeholders to ask questions about the projects. So this gives us insight and transparency into which projects are on progress, which projects are being pulled back for redesign, which projects maybe have increased in cost due to a routing change or a technology change, and it allows us to keep all of that information available transparently.

If you’re interested in this process, I sincerely invite you to visit our TPR website. There’s also an email address here on the website.

So to give you an idea, these data requests yield, you know, thousands of rows of data about all of the transmission elements. Now not all of the transmission elements under development by our investor-owned utilities are generator interconnection related. However, there is a field that identifies which ones are generator interconnection related.

Next slide.

Okay, so stepping back for a minute, I mentioned that we have a permitting reform that we've undertaken. I mentioned that we have this TPR process to track all the projects. When we look at that TPR data, we can use that data to give you a snapshot for projects that have expected in-service dates between 2025 and 2033. So this is like an eight-year period of projects. These are projects that have, let's say, online dates expected between now and 2033.

Of those total projects, there are about 715 of them across the three investor-owned utilities. These are just the projects that have a cost of $1 million or greater. And there are a number of projects. The vast majority of the projects, 575 of them, are not approved by the CAISO. These projects are self-approved by the utility to maintain the transmission grid. A smaller number, 140 of them, are CAISO-approved projects. And then the projects, you know, using this Sankey chart, you can see that many of the projects, both CAISO and non-CAISO approved, are exempt from permitting. So that's the top lightish green.

There are a number of projects in this pile that the permitting project -- the permitting status of those is TBD. It's not yet determined. That's in the darker green.

There are a number of projects in the red that will require an advice letter at the CPUC of Notice of Construction but not a full permitting process, so think of that as a ministerial review.

And there are a small number of projects, the 17 next to the letters PTC and the 7 next to the CPCN, I'll try to do math while I'm talking and, you know, I hope that I come up correctly with 24. Did I do that correctly? Hopefully. Don't do math during a webinar. Anyway, the Permit to Construct and the Certificate of Public Convenience and Necessity projects, those projects at the very bottom in yellow and purple will be permitted through the general order 131E process at the CPUC.

So this gives you an idea of how many projects are underway in the California grid to support reliability, to support generator interconnection, and to keep the lights on in California.

Next slide.

So digging a little bit into the transmission projects that are specifically needed for generator interconnection. In response to a state law that passed a few years ago called SB 1174, the CPUC has undertaken a process as part of the renewable portfolio standard proceeding to review the transmission delays and impacts on generator interconnection specifically. So that prior slide showed you the entire universe of transmission projects. We decided to dive a little bit deeper just into those that are required for generator interconnection and look at which of those projects are delayed and for what reasons and link them up to which generation queue positions are impacted by that transmission delay.

So we've undertaken this assessment now two times. We've finished the assessment twice and we're undertaking the third assessment. We're getting smarter with each round of it. So jumping to the -- jumping ahead to -- the bottom line is that we release our assessment results in the annual RPS report, and so we will do that again in 2025.

So the assessment objectives were just simply to identify how many gigawatts of generation and storage resources are projected to be delayed or at risk of becoming delayed due to transmission projects that these resources depend on. It sounds quite simple. It's right there in the first bullet. It is a complex undertaking. And many generator interconnection projects are dependent on many transmission projects, and then many transmission projects have many -- you know, are likewise associated with many different generation projects. So trying to ask questions and get meaningful data about the reasons for delay is a complex undertaking.

Nonetheless, what we identified in the 2024 assessment, and I believe we can talk about this more later in the webinar, is that we did identify several high-impact transmission projects that are putting multiple gigawatts of in-development renewables at risk. And we also, as you can see in the chart to the right, we categorized the projects by those that are at risk, delayed, and not delayed.

So I think this adds up to a total of about, if I recall correctly, 29 gigawatts of resources. So there were about 29 gigawatts worth of resources in this data set, and a small percentage of them somewhere about 3 gigawatts are at risk, about 12 gigawatts of them are potentially delayed, and another 12-ish gigawatts are not delayed. The orange and the blue distinguishes between storage and RPS-eligible resources.

So we're going to continue to undertake this assessment. We're going to refine our methodology. We did that for this year. We've just received the data for this year, and we're analyzing it now, and there are some links on the slide to additional information that we've provided previously, as well as where you'll find the future releases.

Next slide.

I'm just going to conclude by noting this resource link page has links to each of the major items that I discussed in my presentation, and with that, I think I'm going to turn it to Neil Millar.

Thank you.

MR. MILLAR: Good afternoon, and thanks for having the opportunity to speak today, and I also appreciate the comments Sean and Molly made before.

I will be putting a particular transmission emphasis on these slides. I'll try to avoid duplication as best I can, but I also have to note that the interconnection issue more specifically, Danielle Mills from the ISO will be speaking to that in a later panel about the things we've been doing on the interconnection process side.

I also have to applaud Molly Sterkel for her courage in doing math in public, which is something that I do not have the courage to undertake, so there won't be any math here.

Let's see. If I could move to the next slide, please?

So touching on the same Memorandum of

Understanding that was mentioned before, I just wanted to put the point that this really has been the tightening of the linkages between the resource planning, transmission, interconnection, and procurement, it has really been fundamental to our success in advancing new transmission to meet the state's clean energy goals, and also setting us up within the ISO for the interconnection process changes that were also necessary to align with procurement needs.

Next slide, please.

As Sean mentioned, there had been a ramp up in activity a few years ago. So after about 10 years of averaging around $650 million a year in new capital in our transmission planning process, through the years, through the plans approved in 2022, '23, and '24, we averaged about $5.8 billion in new approvals in each of those years, primarily on policy-driven transmission that were directly the result of the coordination with the resource planning process.

The plan approved this spring in 2025 was a bit smaller at $4.8 billion, but there was a very interesting shift to primarily reliability-driven capital as opposed to policy-driven, recognizing the gains that had already been made in advancing projects to meet policy-driven needs, at least over the next 10 years.

And I also wanted to mention that in 2024, we updated our 20-year outlook document. And we do recognize that the bulk of the transmission identified in the first 20-year outlook, while there were different alternatives perhaps selected, those corridors, those transmission corridors were largely now addressed through the past approvals within our transmission plan. The 2024 outlook, of course, is reaching further out and identifying additional needs, but the linkages have really been successful there.

If I could move to the next slide, please?

The 2025-26 plan that is currently under development is also building on that same level of coordination. I won’t go through the material here, but this slide does set out the resources that are being included in that planning process with a bit of a particular emphasis on some of the out-of-state wind resources that will need more attention over the next few years in this plan and in future plans to come to terms with not only how to get those additional resources to our border, but perhaps additional reinforcements inside our footprint once they get to the border.

Next slide, please.

Also, as Sean had indicated, we do see that we’re actually entering a bit of another inflection point in driving up the requirements. The load forecasts that we’re receiving, the most recent forecasts are showing another increase in the rate of growth that we will be dealing with, and that will require some revisiting of the renewable portfolios we've been using for our approval process in the 10-15-year timeframe, as well as in our 20-year outlook framework. So we do see another shift coming as we recognize a pretty significant increase in the rate of growth now being projected over the next number of years.

That also reflects a change in some characteristics, as we're also dealing with new types of load that have higher load factors, such as data centers in particular.

Next slide, please.

The TED Task Force course had been referred to earlier, but I also wanted to mention one of the other forums that's a bit more tactical for interconnections, and that's the Transmission Development Forum that is also run in conjunction with the help from the Public Utilities Commission. It's also run twice a year. It is focusing primarily on targeted in-service dates, and it focuses on ISO-approved projects, as well as projects that have been initiated or triggered through the interconnection process itself.

So this is primarily of interest to the

development community looking to line up the dates of their interconnections with the transmission projects that they are dependent on. So there is a heavy focus on the dates in that process and giving an opportunity for all of the participating transmission owners to present on changes in schedules since the last meeting and for them to give answers about what has driven some of those delays or changes in their schedules.

Next slide, please.

There are also changes coming our way through the implementation of FERC Order 1920 and the associated orders that did some minor adjustments. This does require the ISO to restructure some of our transmission planning process, focusing on the regional needs.

And what we did see driving FERC's interest in developing this order was, to some extent, the dearth of regional transmission projects outside of the ISO. There really haven't been any regional transmission projects identified under the FERC Order 1000 framework. All of the other upgrades that have taken place inside the Western region have been classed as local facilities, which raises concerns about the level of regional coordination across the West.

So the order was issued in 2024. We are driving to our compliance filing that is due by the end of this year.

I should also mention that that order, largely, the 19-A largely sustained the Order 1920 requirements, but an interesting point is it did further enhance the role of relevant state entities. And I think that just puts a finer point on the recognized importance of the coordination that we have always had in place with our state agencies in which we tightened through the Memorandum of Understanding.

Next slide, please.

I also wanted to mention that the FERC orders will significantly increase the amount of analysis that is necessary, and that also requires supporting input from our state agencies. It does not actually introduce any new concepts for the ISO where we’ve already been implementing for a number of years many of the directional changes that FERC is now requiring on a national level, which I think also bodes well for how well our past practices have been received. These included requirements to conduct longer-term planning, such as the 20-year horizon that we’ve implemented a number of years ago. It enhances the role of state regulators and long-term regional transmission processes, reflecting as well the coordination that we’ve had in place. It requires local transmission and planning inputs into the regional transmission planning process.

We at the ISO, within California, the ISO's role has been to be to lead the transmission planning process both for local and regional facilities within our footprint. And it also requires addressing generation interconnection-related needs that have shown up in the past, and we've already gone far beyond that in the level of integration with our transmission planning and generation interconnection process.

Lastly, it also requires consideration of the use of grid-enhancing technologies, which we have been using, documenting their use in our transmission plan, and actually most recently have also now been providing a report to the legislature about the use of grid-enhancing technologies.

Last slide, please.

So while I totally agree with the comments that Molly and Sean made about the progress that's been made to date, we do recognize that there's a lot of work ahead of us, so we do see three areas of always needing the continued attention to make sure we stay on track. That includes timely procurement of resources so that those resources can give notice to proceed where they're driving local upgrades, as well as their interconnections. We do see a focus needed to be maintained on ensuring the transmission projects are driving to their in-service states. And we do see needing to maintain that level of coordination between the transmission planning with the state forecasting and resource planning activities in order to be successful.

So with that, I'll look forward to any questions and turn it back to the panel, so thank you very much.

MS. NAKAGAWA: Thank you, Neil. Thank you, Molly. Thank you, Sean.

We're now going to go to the dais. Vice Chair Gunda, if you want to start us off with any questions from the dais.

VICE CHAIR GUNDA: Yeah, thank you, Sandra.

I think first I want to just begin by saying, Molly, thank you, Sean and Neil. Just thanks to all three of you for setting the stage really, really well. I think, you know, first of all, I benefit incredibly from all the conversations we're all on, and then also just learning from the three of you constantly.

So, Molly, I'm also not going to try and do math. I tried to do that in an oversight hearing, and it did not go well. I had an order of magnitude mistake I've made. So thanks for braving that.

I think, you know, just, you know, from each, you know, I'm tracking this, but for the record and for the opportunity for everybody to hear, can each of you speak, and I think, Sean, you were kind of, you know, when you were in Commissioner Rechtschaffen's office, you were kind of leading the MOU work from there, you know, at the POU. So can each of you just provide the importance of the MOU? Like, what did the state actually gain from the MOU? What was different before? What's different today?

Neil, you came off mute first, so --

MR. MILLAR: Oh, okay. I thought we were going in order, but I'm happy to take a first shot.

Well, I should admit, for someone who's also been at times tasked with defending some of these transmission projects in the various permitting processes, it's been absolutely critical that we've been able to demonstrate the alignment that the transmission that we're advancing under a FERC tariff-based process, that those transmission projects have been fully thought out in terms of the resources that they're accessing and that they align with state policy goals also reflected through the Energy Commission's forecast. That coordination really addresses the bulk of any stakeholder concerns around our transmission projects in terms of what's driving them.

So we see the integration with the very well thought out Energy Commission forecasts coupled with the Public Utilities Commission's resource planning being absolutely critical to identifying the right transmission and being able to move forward confidently knowing that it will be properly supported in future permitting processes, that it really does reflect the state policy goals overall.

And, you know, good teamwork also means playing your position well, but also not butting into your other team members' positions. And in that role, it's also critical that we occasionally have stakeholders encouraging us to make tweaks here or there to the forecast or the portfolios.

But the level of coordination has been absolutely critical at moving on an integrated, coordinated fashion given the pace of the development that we're moving on. If things are moving slower, we have more time to take a more relaxed cyclical approach, but with the pace of development that's required, we need to ensure that we're as coordinated as possible so that we can move forward effectively and also not move on transmission that is not needed or move on transmission before it's needed.

So that to me is the absolutely critical part, and that's where the Memorandum of Understanding has really helped tighten those linkages.

MR. SIMON: Why don't you go ahead, Molly. I'll clean up.

MS. STERKEL: Perfect. Well, I'll just go back in time a little bit. So in addition to braving math, I'll also brave history here.

So prior to the Memorandum of Understanding, generators were -- there was a chicken and egg problem. Generators knew that they could build resources places, but they lacked the network transmission in order to deliver them to load. And so there wasn't an organized process to identify what those big transmission projects were to -- in order to facilitate and sort of unlock the access to those resources.

So in the early days of the RPS program, we had two major transmission lines, the Tehachapi Transmission Project, as well as Sunrise Transmission Project, which were brought to the state and brought into existence because, you know, the -- don't quote me on this version, but kind of sort of everybody knew we needed this transmission but nobody was willing, no one generator could afford to front the total cost of the transmission in order to bring it to fruition. Likewise, no one who was in a local government wanted to support the authorization of a new transmission line if they didn't know it was part of a coordinated statewide policy driven process.

So the experience that we gained as a state through the authorization of those two projects, as well as some other blood, sweat and tears, that led to this original MOU, which of course we've revised more recently.

And the idea here is to use the best analytical resources we have, put all the data together about where we think the new resources are going to develop and then proactively plan for that transmission. And unless the state is going to stand behind its planning processes, you know, we won't be able to move forward. People will always be second guessing ourselves. Is the process going to be perfect? No, but it is absolutely a required process so that we can have some semblance of order. We can get some transmission built and developers can try to identify projects that can then interconnect to those new lines.

So I don't know, hopefully that little bit of history works.

Sean, you want to close it out?

MR. SIMON: Yeah. No, that's great. I think everything Molly and Neil said on the mechanics is right. And it's sort of, it comes from a -- not that, oh, now we have to coordinate to really leaning into it together with our -- with the independent sort of processes and linking them to really from more of a reflective, continuous improvement mindset, which is a balance actually, because markets want stability, but they're also calling for change. And we hear that call for change.

And then it's just the intangibles of being in conversation together, bringing questions to one another about things, and then extending that relationship into ancillary things like coming in together on a grant with the federal government or looking at a stakeholder process that could have just stayed a normal course, but getting together and asking, are we really meeting the needs of what people are asking?

VICE CHAIR GUNDA: Yeah. Thanks Sean. I think, you know, I just have to say, I mean, I've been in this for eight years, I know, three as staff and about four in this role, four and a half in this role. And over the time, I've really learned to appreciate the complexity of our roles and complexity of, you know, the work that we do, but also the need for working together and how well that's kind of coming forward. So just wanted to say thanks to the three of you and the teams that you represent.

I have a very quick question for Neil, then I'll pass it to Commissioner McAllister. And, Sean and Molly, if you want to add to it, please do.

Neil, just a 30,000-foot level, one of the things we're dealing with across demand forecast, you know, whether it's distribution planning, you know, IRP, is the uncertainty, the vast uncertainty in the demand because of electrification, climate impacts, new loads that may come, may not come. And that, you know, that starting point is translating at different levels to, you know, IRP, DRP, TPP, and then 20-year transmission planning.

Can you give us a little bit on how CAISO is thinking about ensuring both, you know, that rates are protected, you know, but at the same time, we are future-proofing the investments and not caught off guard?

MR. MILLAR: I'd be happy to. I think the most important part there is about the sensitivity work that goes into considering options. And part of that includes picking options that are always a good first step, not necessarily always, I'll say going for the fences with a transmission project, but picking scalable options that we recognize that once you get down a few years down the path, there's always a risk that the load growth softens and that you need to be comfortable that what you've moved on is a defensible plan, that it's useful in the long run, and you're not dependent on some next step in order to achieve the actual benefit of the plan.

So considering what you would do both if the pace accelerates, what are your options, as well as what if the pace of load growth slows, that might mean that some project you're moving on, you can also -- it's one thing to delay a project, it's another different to try to advance it.

So our focus has normally been to try to achieve the required in-service state, monitor the load growth, make adjustments if necessary, but also in the sequencing of transmission projects, consider, well, this is the right first step, how does that leave us positioned if that's where the load growth started to soften? Or what is the next step that you would take assuming the load growth continues? And that's where we think things like the 20-year outlook are also very important to consider about demonstrating what the long-term plan is. And we know that 20-year outlook timing will shift, of course, but that kind of consideration is what we see as being absolutely critical.

I think the other thing I should mention is that, well, it looks like about half of the total dollars approved are on a small number of greenfield projects, and those tend to be the ones that go out for competitive procurement. The other half is spent on upgrades to existing facilities that are much more incremental bites, upgrading existing substations, reconductoring, and so on. And that's also where we need to make sure we're getting the absolute best value out of the upgrades we build, and that includes looking at grid enhancing technologies.

And in that front, you know, we have been using flow controllers more than some of the other grid enhancing technologies. The utilities did need to get through a bit of an entry hurdle, a price hurdle, on starting to use some of the advanced conductors. It required new training, new tools, new practices, also sparing equipment and everything that goes with it. But once they're adopting some of those advanced conductors, it does make it more economic to continue using them in more applications.

So it's also critical that we stay on top of emerging technologies that we can take advantage of to keep the costs as low as possible. And that is a critical component to us in our planning. We know we're spending ratepayer dollars, that these facilities do have rate consequences, and we take that very seriously.

VICE CHAIR GUNDA: Thank you, Neil.

Commissioner McAllister, go ahead.

CO0MMISSIONER MCALLISTER: Yeah, sure. Well, you covered some of what I was going to ask, but I guess I'll sort of distill my questions if I can.

But thanks so much to all three of you. This is just the complementarity and the clear iteration, the clear collegiality and sort of constant communication I think comes across in the presentations, and also just from first-hand experience, I see it happening.

And I guess I remember back to the days when the MOU was kind of being developed under former Chair Weisenmiller, and then with the staff kind of going back and forth, and at the time, it really did seem like something new, but it also was sort of like a course, you know? And, you know, we needed to be doing that all along. Sorry, I’ve got a little companion here.

So anyway, it’s amazing to see just the fruits of all this labor, and just the professionalization and the just intentionality that the MOU has nurtured and brought into reality. So just kudos to everybody, including Vice Chair Gunda. I mean, you know, you were a really key part of that back when, you know, in the early days of MOU and sort of bringing all the juice out of it and operationally making it happen.

So I guess, again, I guess mostly a question for Neil, but all three of you would have some good perspective, I think. And Sean, I think, you know, you were at the PUC during much of this. So you, Molly, I think also. I guess it’s sort of a two-part question.

I mean, so I guess I’m wondering sort of how the -- what we’re talking about today and the Q reform that the CAISO did and how those are sort of matching up, you know, how does this conversation about sort of distilling the need for transmission, how does that sort of map on to managing all the applications you’re getting for interconnection and in different places and, you know, with all sorts of different you know, characteristics and qualities, you know, the hundreds of qualities of each individual project and sort of how you sift through all that and sort of, you know, create the special sauce that says, okay, we're going to do these transmission projects because it matches up to sort of this universe of likely developments?

And then I'll just go ahead and ask the second part. Are you -- so you, I think all of you, mentioned 1920. Are there concerns about sort of FERC going in a direction or sort of what might happen in this realm and the messaging might sort of not support the California, anyway, risks associated with just, okay, how will FERC be paying attention to this area going forward?

MR. MILLAR: Sure, I'd be happy to, and I think just going through the two different questions in turn.

First, when it came to the interconnection process, and, yes, Danielle will speak to the details of those changes in a bit more detail later --

COMMISSIONER MCALLISTER: Right.

MR. MILLAR: -- but I did want to just point out that our interconnection process as it was, was actually relatively successful. And in terms of managing, you know, the original batch cluster study process that was implemented going back now to what 2010 was highly effective, but it was managing tied to the number of applications. It was reasonable for the number of applications we were receiving each year.

The changes we had to make were largely because it became, I don't want to say easy to submit applications, but the sheer number of applications skyrocketed in response to what was seen as more opportunity for competition. But it was really about managing the intake. And the fundamental analysis process has actually been very robust behind it.

But we also had to make changes because we could not afford to have -- as opposed to what people call the backlog, we were dealing with more of a logjam. So many applications coming in at the same time, it stopped anybody from getting through, and that was just not acceptable. So while the transmission planning, the resource planning, and even the procurement was going well, we did get faced with this logjam of an extreme number of applications, partly because it was also comparatively easy to develop and file an interconnection application for storage projects compared to the amount of work that went into developing a much larger footprint project, like a major solar farm.

So that's where we had to make some changes to keep everything else moving. And like I said, Danielle can speak to that.

On the FERC Order 1920 side, the interesting part there is many of the changes that FERC is now requiring on a national level are largely things that we have already been doing. Now, they did add a lot of additional detail behind it, additional compliance requirements, thou shalt do this and this and this, as opposed to where we chose and created options. And that’s where we do see a significant increase in the amount of analytical workload.

But the idea of effective -- you know, the equivalent of a 20-year outlook document, looking out more broadly, better coordination between local and transmission, many of these aspects are things that, I’ll be blunt, we are already doing. They’re not actually -- the sequencing will be changing. The amount of analysis that is required to be done to develop a certain number of scenarios each year, a certain benefit cost analysis is more prescriptive, but the fundamental concepts are things that we were already doing.

COMMISSIONER MCALLISTER: Thanks, Neil, and just kudos to your leadership there. I partnered with Commissioner Rechtschaffen on some comments during the process of the development of 1920 and gained a lot of understanding working with him on that, and with the other states, right, who were sort of like a little bit deer in the headlights, and we weren’t, you know, we had a lot to work with.

So I guess, kind of wondering, well, I’m inviting speculation, so you don't have to answer, but, you know, there's no way to know really, but I think with the changes at FERC, I wonder if this will continue to be a priority or if there'll be consistency, you know? No way to know until we sort of see them make some decisions, I guess, but was kind of wanting to hear any sort of, you know, how we can maintain a high level of immunity to any of those sorts of changes?

MR. MILLAR: Well, I would say that when it came to our FERC, the 2023 compliance would underpin the interconnection process enhancements, that was a bit delicate because we were proposing some major changes, but then the foundation got moved out from what we had to this new order. And it was a deliberate strategy recognizing we had to have that filing to be successful and quickly successful. We really aligned our requirements, our compliance filing with the order in as great a detail as possible.

With FERC Order 1920, we have a bit more latitude there where there are invitations that if you're doing something that's already considered superior to the process they've laid out to tweak but explain why you're doing it differently, and we think that the emphasis on regional planning is recognized as being a priority regardless of what other issues are going on. There are certainly concerns around how perhaps administration concerns about renewable generation and so on are being handled. But on the fundamental intent that the transmission grid needs to be reinforced and needs to keep up with the emerging requirements, I think we're more comfortable there that we're seeing strong alignment and not expecting, at this point, not expecting any changes on that side.

COMMISSIONER MCALLISTER: Great. Thanks. I see we're a few minutes over, so I'll stop there and pass it back to Vice Chair Gunda and --

VICE CHAIR GUNDA: Yeah, thank you.

COMMISSIONER MCALLISTER: -- I want to say thanks to the panelists. Thanks.

VICE CHAIR GUNDA: Thank you, Commissioner.

I think we have one question in the Q&A, so let's have that answered and we can go to the next panel.

Yeah, do you want to, Sandra, can you --

MS. NAKAGAWA: Kelsey's going to jump in here, yeah.

MS. CHOING: Okay, I'll read it. So it's from Tatiana Brennan from the County of Santa Cruz, and the question is, "Who can counties contact to learn more about their role in the MOU and the role of CCAs? "

VICE CHAIR GUNDA: Go for it, Molly.

MS. STERKEL: Yeah, maybe I'll take that.

So CCAs are one of the types of load serving entities that participate in the CPUC's integrated resource planning process. And so the CCAs are feeding their information into the CPUC's integrated resource planning process, which happens iteratively. So while there is uncertainty, I'll just mention that the process happens every two years, and so, you know, that gives us an opportunity to adjust as a CCA adjusts.

And in terms of counties, so depending on whether or not you're looking at the resource planning side or the resource procurement side, you know, counties can participate as interveners in the integrated resource planning process. They also can interact with both the CPUC and the CPUC -- CEC and the CPUC in our permitting roles and our roles as permitting agencies. Certainly, we work with counties all the time on issues related to permitting.

So I would just say that one of the things I hear from counties a lot through the Tracking Energy Development Task Force is just how hard it is that there are so many projects out there. And I thought maybe this is just a little perspective we could end on here.

So Neil mentioned it was we had this log jam. There were just so many projects in the queue. Certainly, those projects are knocking on the doors of county officials, which is overwhelming. And so trying to narrow that down to the projects that are more viable is a useful outcome of the interconnection process enhancement initiative.

But from a ratepayer perspective, we do like to see competition because we want to have some choice among projects, and hopefully ratepayers benefit from there being multiple projects in the development pipeline so that we don’t have to choose only from one project, that we have a number of projects that we can choose so that we can find the most cost-effective project for ratepayers, and so hopefully ratepayers can benefit from that.

So I just wanted to mention that I know counties often struggle with the number of projects that they’re interested in developing in their area and knowing which one of those are going to actually move forward given all the uncertainties we’ve already talked about.

So anyway, I would -- long story short, I would also direct folks to the Tracking Energy link that’s on my last slide at cpuc.ca.gov/trackingenergy, and there are a number of contact names and information there, that’s a great place to start, so thanks.

MR. SIMON: Thanks, Molly.

Kelsey, is that the last question?

MS. CHOING: There’s one more question from Kanya

Dorland at Cal Advocates.

"So there is a trend of -- or there's a trend in the U.S. of data centers interconnecting with existing generation or retired generation. Will the joint agencies need to develop a policy to respond to this type of interconnection in California?"

MR. SIMON: Who wants to take that, or do we hold it for after the next panel?

MS. STERKEL: It's a very interesting question. I was going to say, Kanya, it's a very interesting question. I think your question is kind of getting specifically about generators supporting sort of on a behind-the-meter role. So perhaps that's a more complex question than we have time for in brief time here, unless Neil wants to jump in.

MR. MILLAR: Well, it's Neil. The only thing I would just add, though, is that whether it's load connecting behind an existing generator or connecting first and then wanting to have behind-the-meter generation join later, we do see fundamentally that the role of managing load interconnections is first and foremost with the incumbent utility, and that's where they apply and deal with. So I just wanted to get that out in front, because that does require, then, the coordination across those entities to ensure that we have consistent policies. But that is, first and foremost, a load interconnection is still first and center, dealing with the utility in their area.

MS. STERKEL: Yeah. It is also worth mentioning that when Sean showed that inflection point in the load growth, I do want to mention that there were a lot of things that went into that inflection point, and we know that load is growing. Perhaps some of the things that the CEC was expecting 6 or 10 years ago have not happened, but then we have AI data centers happening, but that's a completely normal part of the load forecasting process.

So I would say that we are well-situated as a state in terms of we have been getting ready and gearing up for load growth, and we're not being caught flat-footed. That it's actually happening.

So that's just a point. A question we get a lot, is, you know, are we going to be able to serve some amount of data center load? And I think that there's -- you can save that for the IEPR workshop on load forecasting and ask that question there, but I do think on a very high level, we have been planning for some amount of load growth.

MR. SIMON: Okay. Great. Thank you very much.

Okay, I'm going to invite our next panel up. And panelists, I think what I'll do is I'll introduce all five of them. We are a little bit behind time, and we can introduce again if needed, if the handoffs are -- don't go as early as we need.

So, first, Danielle Mills, who's the Principal of Infrastructure Policy Development at the California ISO. Then Jens Nedrud, Director of Transmission Planning at Pacific Gas & Electric Company, followed by Manuel Avendano, who's the Senior Manager of Central System Planning at Southern California Edison Company. And then from LADWP, Ashkan Nassiri, Assistant Director of Power System Planning Division, and Brian Biering, representing American Clean Power California to represent the development community.

So, Danielle, if you are ready.

MS. MILLS: Thank you, Sean, and good afternoon, Vice Chair Gunda and Commissioner McAllister. It's great to see everyone and all this interest in interconnection and energization in California.

So I'm Danielle Mills. I'm the Principal for Infrastructure Policy Development. And I'm just going to focus on, primarily, on the ISO's interconnection reform efforts for getting projects interconnected to the transmission grid.

So I'll start on the next slide by just walking you through what the ISO considers to be a part of its resource interconnection standards. There are multiple sort of steps in the interconnection process, but it’s all designed to ensure safe connection of generating and storage facilities to the grid. So we want to make sure that as a project is developed, we can safely deliver that power on the grid when it’s needed and during times of stress system conditions in some cases as well.

So the first step of this process is the interconnection request and the study process. This is really where interconnection customers have to apply to have a space in the ISO interconnection queue. And that’s where -- this is really where I would say the bulk of our reform efforts have taken place over the last several years.

The study process is also very important in this. It’s, you know, how we provide some degree of certainty to the developers of what their costs will likely be and what the timeline is for development of network upgrades or infrastructure that will be required for them to bring those projects online.

The next step of the process is the allocation or retention of transmission plan deliverability. Deliverability is sort of the thing that allows a resource some assurance that it will be able to provide power during times of stress system conditions. So it needs to be studied very specifically by resource to make sure that it will be able to count on that resource for resource adequacy at times when we need it most.

Then, kind of in parallel with the transmission plan deliverability allocation process, projects move through contract development and sign interconnection agreements. And then once interconnection agreements are signed, it moves through to the queue management phase, which is where the ISO really tracks and monitors projects that have been in the queue, have signed GIAs, may have obtained deliverability allocations, and are just kind of hitting milestones. And there's a series of milestones that projects have to demonstrate their ability to meet in order to remain in the queue.

And then finally, we have new resource implementation, which is kind of the final step where projects enter and compete to -- enter and complete a series of steps to ensure deliverability and, you know, safe operations so that we can sort of test these projects before they are actually incorporated and interconnected to the grid. So that involves the steps of syncing and running trial operations, and then ultimately results in that project coming online and participating in the market.

Next slide, please.

So here is the requisite MOU slide. I do think while it has been maybe somewhat redundant to stakeholders today, I think that's a good thing. I think, as Sean said, this is really a lot more in practice than some of these simplified graphics may suggest.

But the pieces that I want to highlight in the MOU process for the interconnection process at the ISO in particular really fall after transmission. So I think previous panel did a great job of highlighting particularly the planning connections that happen and the handoffs from the CEC's demand forecast to the Public Utilities Commission's resource plans in the IRP and how that factors into the ISO's transmission planning process. But then there are additional linkages to the procurement process with load serving entities and the interconnection process embedded in this MOU as well.

So when the transmission plan is approved every year, the ISO identifies zones and looks at areas where there will be then planned and available transmission capacity. Those zones then suggest to load serving entities the best locations for new procurement and new project development. And so interconnection customers can look at our transmission plan, look at some of the data that we provide, and get a better sense and more clarity and certainty of the best areas for resource development based on these great planning inputs from the agencies and then know that they'll have a higher likelihood of success or potentially prioritized projects because of the interconnection reform that we've implemented. So the zones are really important from the transmission planning.

And then we're also -- we now include an opportunity for load serving entities to actually participate in the interconnection review process and sort of put support behind individual projects that LSEs think they may have some interest in building and -- or contracting with, rather than building. And so that can help those projects then move into the study process so that the products that the LSEs are interested in have a higher likelihood of success in achieving commercial operation, which helps for procurement and contracting on the other side of the interconnection study process.

I also want to mention here that while this slide doesn't expressly mention local regulatory authorities, we also have a process in our transmission plan where we incorporate the needs of different local regulatory authorities as well, so that we're making sure that we're getting kind of an ISO system wide perspective of the needs for transmission and we allow -- you know, we participate with LRAs in the interconnection process as well and allow non-CPUC jurisdictional LSEs to participate in the interconnection process and the supporting as well. So just wanted to make sure we didn't miss that.

Next slide, please.

So some of our changes were really the highlighted, the need for these changes were really highlighted in 2022 and 2023. At that time, CPUC had just put out a couple of new procurement orders, quite large procurement orders compared to what we had seen in the years prior to that. And, you know, there was a SB 100 study report that indicated that we might need to see something like seven gigawatts of new nameplate capacity coming online every year to achieve our policy objectives.

So there was this significant rush of interest into the ISO interconnection queue, which resulted in Cluster 14, which was the ISO's first, what we called super cluster, where we had, you know, more than double the amount of projects than we had received in previous clusters, which really not only was time consuming for the ISO to look through, but I think more importantly, when you study that many projects, the results of those studies lost meaning to individual -- (clears throat) excuse me -- individual interconnection customers who were interested in getting information and trying to get some more certainty about their projects.

So the goal here -- and when we saw that this trend was exacerbated in Cluster 15, we really came to realize that we needed to get study volumes back down to meaningful levels and manageable levels. And when I say meaningful, we definitely didn't want to just pick a number because we wanted to ensure that we were going to be studying sufficient projects to allow for competition after the studies were complete, competition for procurement, as well as to account for some degree of project failure. If projects decided to withdraw or companies shifted priorities elsewhere, we wanted to account for those. So we focused on trying to reduce studies to a level that aligned with the system need, and the system need was also focused on the transmission plan availability and the availability of existing transmission.

So, from there -- we can go to the next slide -- we implemented a series of reforms that were really focused on not only reducing study volumes to more manageable levels, but also on queue management, alignment with the state resource portfolios in terms of the types of technologies and the locations of technologies, and the amounts of different types of resources that we would need, and really also focused on project viability.

And so, those reforms primarily were packaged in Track 2 of the interconnection process enhancements, which we completed last year in 2024 and was approved by FERC in September of 2024, and then the next day it was implemented with the reopening of Cluster 15 for resubmissions. And

I'll share a little bit of the results from that on a future slide.

We also, as Neil mentioned, had to comply with a FERC order that came out that we complied with last year, starting in spring of 2024, and was recently approved by FERC in May of 2025. And this was really establishing sort of baseline requirements throughout the country for all transmission providers for interconnection reform. And so, as Neil said, we decided we would just adopt the order 2023 requirements pretty much whole cloth, and then build all of our additional reforms on top of that.

And then Track 3 of the interconnection process enhancements initiative we completed last, earlier this year and was approved by FERC in June of 2025. That process was more focused on the deliverability allocation process, as well as establishment of a new type of process that we're calling the intra-cluster prioritization. The intra-cluster prioritization was largely driven by Cluster 14.

Now that we've completed Cluster 14 studies, and you'll recall, Cluster 14 was the first super cluster that we had, so we studied a lot of projects, and as a result, a lot of projects received very long lead times for their infrastructure needs and very high costs. So there was a lot of movement and change within Cluster 14 as a result of those studies. And I think a real desire to get as many projects from Cluster 14 online as quickly as possible, while the others wait for any associated infrastructure upgrades.

So that's a process that FERC has recently approved and that the ISO is moving forward with right now, so that we can take, you know, the best projects that are best situated from Cluster 14 and start to move on those as we wait and try to, you know, advance all of the additional infrastructure needs that we are facing in the next 5 to 10 years.

And then finally, we still have yet to file our deliverability allocation process modifications. We plan to file those in early 2026. They were less urgent with FERC because we don't plan to have another deliverability cycle until 2027. We're going through one right now for Cluster 14, and then we'll skip 2026. So we have some time to present that FERC.

Next slide, please. Thanks.

And so the reformed interconnection process that I mentioned, the focus was on interconnection request intake to really get to more -- get the best projects forward into the study process, so that we knew we were studying the best of the projects that we were going to need.

So we established a cap for the study process at 150 percent of the transmission capacity at each zone, and we used the zones from the Transmission Plan. This 150 percent value, as I mentioned, was really important to ensuring that we had enough resources coming through the study process to allow for additional competition and potentially project attrition as well. But to get to that cap, we had to filter these projects down. So we started with the order 2023 requirements.

In particular, order 2023 requires site control for a certain facility, for all facilities, and so that was a new baseline requirement for projects coming into our queue. Then we released a lot of information from the Transmission Plan and from our deliverability process to interconnection customers so that they could look at the different zones and look at the various locations available for interconnection and identify where they wanted to submit their request.

We also prioritized development in areas with available transmission while still allowing for development outside of those areas through the merchant pathway. So we did want to ensure open access here. That’s very important and feel that we were able to provide that in the revised process.

And then from there, we scored process -- or scored projects based on commercial interest. And this is where load serving entities participated in that process and actually awarded points to individual projects that they were interested in ultimately contracting with. We also looked at project viability and system need indicators for scoring.

And then if projects were scored within a zone to get into the study process, we had two tiebreakers that we were ready to lean on to determine which project would advance. The first that we leaned on was the distribution factor analysis and that basically measures the project's impact on the grid at a certain POI, a point of interconnection. We did have a few projects that were tied and the ties were resolved by the distribution factor. We also had a plan to go to an auction if there was still a tie at that point, but we did not have to go to an auction for Cluster 15.

So we did manage to get study volumes down to that manageable amount. We still probably need a couple of years to look at this class of projects as they come through to assess the viability and whether these indicators did actually identify the best and most viable projects.

Next slide, please.

We have some data from Cluster 15 that does suggest that when you look at initial interconnection requests in 2023 for Cluster 15 versus the resubmissions in 2024, right after these changes were implemented, we saw a 73 percent reduction in the number of individual interconnection requests and an 80 percent reduction in the capacity of the cluster. But we still have 68 gigawatts in Cluster 15, and so we do feel confident that there are sufficient resources, not only in the queue but really in Cluster 15 alone, to make sure that we’re able to meet our near-term reliability needs and our long-term policy objectives.

Next slide, please.

So we are implementing a new -- or we’re initiating a new stakeholder process that we’re calling Interconnection Process Enhancements 5.0 because it’s the fifth Interconnection Process Enhancements initiative that the ISO has held. This is really focused on just revisiting topics that we were asked by stakeholders to look at and to monitor as these changes took effect.

You know, these are big changes that the ISO has made, really unlike changes that have been made in other parts of the country or other parts of the world. And there was some anxiety, I think, on all sides about implementing this scale of change. And so we did want to really make sure that we were giving space to look at these issues year by year as we go through each cluster and making sure that we are taking care of any challenges or any new issues that may be emerging as we move through this process.

So this is just a sampling of some of the concepts that we’re exploring. We actually had a workshop this morning, so I may not believe it because I think we’re also running low on time. But some of these do -- I do want to highlight that some of these do include the need for continued coordination and alignment with the state agencies and local regulatory authorities as well, particularly everywhere where there’s an interaction with procurement.

You know, I think what Neil said is very true in this case. We want to play our positions the best we can, but we don’t want to step on anyone’s toes. And so we have to respect, you know, jurisdictional roles here and just support one another as best we can as we move through these processes.

Next slide, please.

And just to emphasize, you know, where we’re going, we’ve seen the need for I think roughly 100 gigawatts by 2040 was in the portfolios that Molly showed. We have more than sufficient resources in the queue to meet those. In fact, we still worry sometimes and wonder sometimes that we have too many projects in the queue that are lingering, that we need to find some alternative pathway for either withdrawal or transitioning those resources to some other type of resources or something because there is really still a very large volume of projects in the queue.

We would like to see as many of these projects reach commercial operation as possible to satisfy all of California's, you know, policy and reliability needs. But if projects become a hindrance to other projects behind it, then we do need to do something to move those projects out. And so we will be focusing on that in a continued way as well.

And then finally on the next slide, I'll just walk through some near-term milestones too. I'll show this slide for two reasons.

One, to encourage people to participate in our Interconnection Process Enhancements 5.0, which is in the early stages and that means it's really the best time to get stakeholder feedback on how the process is working and whether there are any changes. We always like to hear those ideas early in the process rather than later because we have more flexibility to actually address them really in the process.

And two, I also want to highlight the TPD, the

Transmission Plan Deliverability Affidavit deadline of August 29, 2025. We had a market notice go out on this the other day. But I think this is the kind of deadline and the type of process alignment that we've all been trying to emphasize here. I know there's been a lot of focus on, you know, near-term procurement and procurement to meet various commercial milestones and policy and reliability needs. And this TPD affidavit deadline is one opportunity for projects to seek and retain deliverability, which is going to be critical going forward. So I want to make sure that there's just clear awareness of that as we move forward.

And with that, I'll stop and see if there are any questions after the other panelists go and just express my appreciation to everyone here today for being part of this and holding on as we go through these changes.

MR. SIMON: Thanks so much, Danielle.

And there are some questions coming in, in the Q&A. Some of them are probably answerable in writing, so the team can work together offline and get written responses. And then we'll circle back to questions that are coming in and address them again.

And I see Jens Nedrud has joined from PG&E, so I'll hand it over to you.

MR. NEDRUD: Sounds great. Thank you. I hope everybody can hear me correctly. I'm happy to be here and have the conversation with everyone today. I'm Jens Nedrud, Director of Transmission Planning for Pacific Gas & Electric.

And I'll just start by giving an overview of, on the next slide, there we go, an overview of where we're at from a company perspective. I think we've heard today; right? There's a lot of increased need for how we interconnect generation along the way. PG&E is definitely a supporter of ensuring California can meet our energy goals. So we'll talk a little bit about the status of generating interconnection at PG&E, things we are doing right now and implementing to help improve that, as well as some items for continuous improvement along the way.

We've heard it a few different times from Neil and Danielle about the really dramatic increase in size that we saw for generator interconnections in the last couple cycles. We've done cluster studies for a long time, but really, Cluster 14 was a tremendous increase in the amount of generators that want to get connected, which is a good thing on one hand and really reflected, I think, a low barrier to entry for a lot of resources. But improvements recently and improvements that we hope continue in the future, try to pare those down within prioritized projects that are really most ready to interconnect.

As we continue to see over past clusters, a really high withdrawal rate, a little over 70 percent of the generators that want to interconnect actually follow through that process and get interconnected over time. So the question is: How can we really clean that backlog as we move forward so we can put both the resources, time and energy, as well as the materials towards getting generators connected that are ready to go?

If we move to the next slide, PG&E's made a lot of strides this year and last year and improvements to help ensure we can meet the generation interconnection requirements that are needed of customers in a timely fashion. They really fall into four big picture buckets.

One of those is some new tools and process enhancements. We've been working with GridUnity to pilot that to help streamline the CAISO intake process in partnership with CAISO and are incorporating that in the new cluster, and I'm pleased with the results. There's always speed bumps along the way with any improvement, but I think we're getting in a really good direction there.

The other two pieces I'll highlight is we've had to ensure that we get out of our own way and streamline some of the agreements that we make as we move forward implementing these. So we developed some pro forma contracts for some of our engineering procurement agreements, and also worked through ensuring that projects, once they're started, continue to move forward, even if some of the procedural contractual parts delay, because stopping and starting a project wastes more time than really is beneficial. So those have been helpful to keep things on schedule as we move forward.

The other big area has been long-lead materials. It's not only a problem for us, it's a problem across the country and really globally. The demand for transmission materials has skyrocketed, and so we have been really revamping how we both authorize and bulk order materials and broadening our supply chain. Circuit breakers, in addition, and transformers, lead times have dramatically increased, so you need to buy more of those sooner, and we've been working through that.

The other, I think, gem that's been found is working with developers along the way that have already pre-negotiated manufacturing slots, and how can we take advantage of those along the way through our process. So that's helped at least reduce some of the lead time for materials.

As I mentioned earlier, the high amount of analytics required to develop solutions, not only solutions that are, so to speak, plug and play new infrastructure, but also those that might rely on grid-enhancing technology, it takes a lot more analytical power to make that happen. So we have broadened our resources to support the increase in demand, starting up a dedicated engineering team to support some of the substation interconnection engineering, as well as broaden our generation and load interconnection planning teams to be able to more nimbly support the work and the studies that are needed to get this out in a timely fashion and identify the right solutions for customers, and then be as cost-effective as we can with the right infrastructure upgrades.

The fourth one is the capacity delivery center. If we move to the next slide, that has really been an opportunity for us to really help facilitate getting projects done for customers in a timely fashion across our entire portfolio, but a lot of emphasis on the customer-driven programs around the generation and large load area.

It has started and is withstood up at the PG&E's Oakland general office, and it really brings together all the stakeholders from across the company to make sure we've got visibility of this portfolio of work. It looks like a massive control center with boards everywhere highlighting the entire process from end to end on what's happening with the different delivery projects, what's going well, what's falling behind, how can we work together to catch up on those that are falling behind and produce the right mitigation plans in place to help move forward with that.

It’s also held as a great lean operations hub, so we can visualize that process from end to end and work on ways to improve efficiencies. And it has really helped us transition and accelerate a lot of projects, helping to beat those in-service dates promised to customers in previous clusters.

Moving to the next slide, there’s also been a number of other improvements that we’ve made, and many of these in partnership with CAISO, as well as ourselves. One of those is really in bringing transparency to site selection. So that starts with heat maps that CAISO has implemented as part of the FERC Order 2023, and also as part of their interconnection process enhancements to help drive generators to places where the transmission capacity is available to support them.

I think the other big -- we’ve gotten a lot of positive feedback from it, it’s been a win-win for both PG&E and customers, really developers, has been a Developer Forum where we provide updates on what are the in-service dates and what are the projects we’re moving forward with, how are we making the right improvements and driving towards on-time delivery for those in-service dates, or explaining why things have slipped and are delaying in a very transparent way. I think that’s really helped to gain trust on both sides so everything’s moving forward as quickly as possible within the confines of what we can all control.

The second big bucket is how do we mitigate short-circuit duty; right? As we are investing in a much more robust 500 kV network, we have a lot of challenges on how can we make sure the equipment continues to support that moving forward.

One of the pieces we have put into place is really ramping up and are really only buying breakers that handle high short-circuit duty and are able to meet that standard. That's specific across our 500 kV circuit breakers. And in a time when long lead items like breakers are difficult to come by, ensuring that we are thinking about the future and ensuring they're ready and robust enough to deliver what's needed is really important to making sure we can deliver in the meantime.

In terms of advanced technologies, right, there's, of course, GETs, but those alternative transmission technologies are important to us, both to find the right solution for customers and to make sure we're using costs to be as cost-effective as possible. We, of course, continue to value advanced conductors, and it definitely has a sweet spot that we have identified to help increase capacity on existing lines where possible.

Power flow controllers are another great technology that we are investing, investigating, and in process with the project now, as well as some tower raises to try to identify. When you're looking at incremental capacity, there's some great cost-effective tools to do that while making sure you've got the analytical power to be able to study that in the time frame required to make sure we get back to customers on these cluster timelines.

The other two buckets, and these are really, in some ways, cutting-edge and technology and tools, we're partnering with a number of different, I think, developing partners to figure out how we can automate some of the generator model validation, some of those pre-study work and get simulations visualized in a quicker fashion, as well as ramping up to cloud-based platforms so that our turn times on studies, again, ways to make that analytical process more efficient so we can spend more time developing the right solutions for our customers in a cost-effective way, which is really what generating customers are going to want, lower the cost to entry, and that helps everyone get more resources online.

So those are some of the ways we're streamlining things.

If we go to the next slide, I touched base on this already a little bit in terms of advanced technologies, but just to -- one of the really important pieces to making this more efficient is how can we scale this up? I think there’s still a gap that we are exploring ourselves as we’re piloting projects. What’s the real true cost of advanced conductor upgrades across the system and as well as power flow controllers? How can we pilot that to look at other technologies like dynamic line ratings? It all gets great incremental capacity. Of course, what’s the real true cost and where’s the sweet spot for is that just greenfield projects, or are those also on rebuilds and upgrades? And when is the right time to make that kind of investment on behalf of customers looking for both reliable service, but also to get generators interconnected as quickly as possible?

Let’s move to the last slide that I’ve got to touch base on, at least my portion of the panel, looking forward on what are some of the key improvements that we need to make to streamline the process as existing queuing and beyond. I think we’ve heard from Daniel and others at CAISO. They’ve made great strides, and I really applaud their efforts in their interconnection process enhance improvement. I think it’s helped with Cluster 15, and I’m hoping future clusters, to streamline that and bring the most ready projects to the forefront so they can really be evaluated and move forward.

What we’re seeing as part of the bigger

longstanding issue is how do we clean up the backlog that's already been approved in Cluster 14 and previously? There's about 30 gigawatts in PG&E's cluster that's in that state. And so some of those, how can we eliminate those that are parking in the queue, those that have been sitting there for one to two years without moving forward incrementally? And part of the concern is if those projects drop out or decide not to continue for some reason, it has a ripple effect to future projects, both from a study standpoint and how you fill up those upgrades or spread those costs to others. So that's a really important piece of clearing it up.

We're also very supportive of any enforcing any additional financial commitments requirements that we have on today and future clusters to try to make sure that commercial past projects are really ready to implement and ready to get interconnected. And that also includes financial security postings to ensure that projects that are really ready to commit can move forward.

We've talked already a little bit about how we streamline study timelines. I think there's been great improvements, but there's more work to do on those past projects to ensure that that backlog is cleared up. I'd really like, and great to Danielle, to talk about how they've looked at narrowing down the scoring system along the way. So we're excited about that piece and really bringing through projects that are ready, but the right amount of ready projects to the forefront on planned transmission capacity per zone, so that's been a great enhancement along the way.

I think the last piece that we'll highlight, we've noticed and it's been a big thing for our developer customers along the way, that continuous communication to make sure they are up to speed on what they really need, what their flexibility is or isn't on their projects, and how we can both work together to meet their timelines and resolve issues practically has been a really important piece of the partnership we've had with customers to ensure we can continue to support California's clean energy goals and get these resources online as quick as possible.

With that, I'll wrap up my portion, and I'll hand it back to you, Sean. Thanks.

MR. SIMON: That's great, Jens. Fantastic job covering that and love ending on the communication piece.

Manuel, if you're with us, please turn on your screen.

MR. AVENDANO: Hello, everyone. Thank you for the opportunity to speak today on behalf of Southern California Edison.

Next slide, please.

So at SCE, we've been working on several initiatives to make grid interconnection smoother, faster, and more resilient. There are five key efforts listed on this slide, but in the interest of time, I'm going to focus on the first two. I think these are where we have made some of the most impactful recent progress.

The first is our commissioning procedure for inverter-based resources. This is all about consistency, making sure every project goes through the same rigorous checks so we can verify compliance, confirm that the models match reality, and address any issues before projects come online.

The second one is a recently established intra-cluster reliability network upgrade authorization process. In simple terms, it lets the most ready-to-go projects use the grid capacity we already have, so instead of waiting years for long-lived reliability upgrades. That means getting clean energy connected faster and without compromising reliability.

The other three items, work order improvements, advanced procurement, centralized remedial action schemes enhancements, those were discussed in detail at April's Transmission Development Forum, so I won't revisit them today.

So let's dive into the commissioning procedure.

Next slide, please.

The purpose of the commissioning procedure is straightforward. We want to give interconnection customers clear, consistent instructions for how to test their projects before interconnection. This way, everyone’s working from the same playbook, right, whether the project is connecting to our transmission or our sub-transmission system. The objective is to make sure two things happen before a project goes live. First, that the plan settings meet all of SCE’s performance requirements, and second, the models the customer has provided match the equipment installed in the field. That’s critical because accurate models are the foundation for reliable planning and grid operations.

In terms of scope, this applies to any inverter-based resource project that’s 20 megawatt or larger and seeking to interconnect at voltages above 50 kilovolts. Ultimately, this procedure is about avoiding surprises, so when a project is energized, we know it will perform exactly as expected. That's right.

Next slide, please.

So once a project enters our commissioning process, we make sure it goes through a set of key performance tests. The goal of all this is to verify that the facility can operate exactly as required under real-world conditions.

We start with the voltage reference step and the system voltage step test which checks how the automatic voltage regulator responds both to changes in its own set point and to actual changes in system voltage. So that's where we confirm the plant can meet our voltage and reactive power requirements.

We also look at run rate to verify that the plant can adjust its output up and down within the required time frame.

We also look at reactive power capability to ensure it can supply reactive power within the required power factor range while maintaining rated active power.

Primary frequency response is another critical one. This measures how quickly the plant senses frequency changes and adjusts output to help stabilize the grid.

And lastly, for battery storage projects, there is a restricted charging/discharging test which confirms if the system can limit charging or discharging to the levels identifying interconnection studies.

So why does this matter?

We've seen that inconsistent or incomplete commissioning can lead to delays, retesting, and post-energization performance problems, so we're trying to help everyone with standardizing the process so connection customers know exactly what's expected or teams can plan resources more efficiently, and the CAISO can count on, you know, accurate operational performance from day one.

Next slide, please.

We view these not as just one-time improvement, but it's a living procedure updated as technologies evolve, as we gain operational experience, as we continue to coordinate with the CAISO and, you know, the other utilities to establish regional consistency. Version 1 of this document was published last year, and version two should be posted within the next few weeks, so this is a publicly-available document in case people want to, you know, start looking at it, and obviously available to all of interconnection customers.

Next slide, please.

So our second focus area addresses a different bottleneck, how to let the most ready projects move forward sooner, even when the network upgrades are still pending.

So with a little bit of background, within a CAISO interconnection cluster, multiple projects often depend on the same reliability network upgrade. So traditionally, these projects will have to wait until the upgrade is complete, even if the grid could temporarily accommodate some of them without violating any reliability criteria. So the intra-cluster prioritization process is changing that.

So working with a CAISO scoring framework, we are conducting studies to identify which projects have eligible reliability network upgrades, can use existing available capacity for alert interconnection, and which ones, as well, are most development ready and can be safely integrated ahead of long lead upgrades.

For example, as you can see summarized in this table, in Q-Cluster 14, we've identified multiple projects in areas like Devers, Serrano, Pardee, where earlier energization may be possible. So this is not a blanket first-come, first-served approach. I think this is -- we see this as a structured prioritization that balances a couple of things, developer readiness, available system headroom, right, and our obligation to maintain reliability for all customers.

This is an ongoing opportunity, right, an opportunity to refine our technical screening criteria to coordinate closely with a CAISO on identifying temporary operating limits or mitigations, and to work with interconnection customers so they can align project schedules with some realistic prioritization outcomes.

So in closing, both efforts, the IEPR commissioning procedure and the intra-cluster prioritization, both have the same auxiliary interconnections without confirmation of safety and reliability. We know that all these interconnection challenges cannot be solved by one utility or regulator or the CAISO alone. I think we all agree that the key is coordinated, transparent, adaptive processes, right, that evolve with technology, policy, and the aggregates themselves; right?

So, we are committed to continue this work, sharing lessons learned, collaborating with CAISO, PG&E, SDG&E, other utilities, all the stakeholders here today, so to ensure that clean energy resources can connect to the grid as quickly and as reliable as possible.

With that, I thank you. Thanks, everyone, and I look forward to the discussion. Thank you.

MR. SIMON: Thank you, Manuel.

Ashkan Nassiri will join us next from LADWP.

MR. NASSIRI: Thank you, Simon.

Good afternoon. Happy to be here. Ashkan Nassiri, Assistant Director of Power Planning for LADWP.

Next slide, please.

So before I dive into today’s topic from the perspective of I think, the only publicly owned utility here, I’d like to start with a quick overview of our power system. DWP is a vertically integrated utility. We serve over 4 million customers in Los Angeles and Owens Valley.

We are also a balancing authority, and the City of Burbank and Glendale are part of our BA.

We own and operate our generation, transmission, and distribution system. We have about 10,000 megawatts of generation, a little bit over 4,100 miles of transmission system, and about 11,000 miles of distribution system. And to put things in perspective as our size in terms of capacity, we hit our all-time peak demand of about 6.5 gigawatt back in 2017.

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Our story is a little different here. Unlike the others that presented here today, our generator interconnection requests are processed in a serial fashion at this time. With the sheer number of interconnections requests that are coming in, especially with every utility pushing hard to meet RPS goals, the traditional serial process isn't cutting it anymore, and the projects are stuck in queues for years before they're even studied. And when one dropout, one project drops out, it triggers a whole chain of restudies, which slows down everything even more.

On the technical side we have run into some challenges. Sometimes some of the models that we have received from customers are incomplete or inaccurate, and sometimes they show up late, and that makes the process even less efficient. But LA is transitioning to cluster study this year, by end of this year. Frankly, we are very excited about it as we move to cluster study, but we are expecting some of these issues to stick around. We saw earlier presentation from a Daniel CalISO and PG&E. I think they're on the fifth round of cluster improvement.

Next slide, please.

So as I mentioned we are working on shifting our current serial interconnection process to a cluster-based approach. As we do this transition, we are looking at dividing our system into two or three key areas. And all these areas, as you know, will be studied at the same time, all concurrently.

One thing to mention: whenever we need to make a change to our open access transmission tariff, like this case, moving forward to the cluster-based approach, we have to go through a series of approval, which includes our Board and the city council. And that can -- as you can imagine can slow things down a little bit.

Next slide, please.

So we are really excited about improving both efficiency and transparency of our interconnection process. There are a few key features that we are hoping will make this transition smoother and more effective for our customers. Some are lessons learned from the years of experience that CalISO and some other BAs and utilities have with cluster studies.

First we are moving towards a single annual application window for both small and large generator projects. That should help streamline how we intake and plan for new projects. Instead of advancing projects based on when they apply, we are prioritizing based on readiness, things like technical completeness, site control, permitting status, things that are tangible and can ensure a higher chance for a project to go forward.

We are also raising the bar at the submission stage. Applicants need to meet stricter criteria upfront, and we are hoping that should help improve the quality of our study and cut down on the speculative projects, which usually don’t move forward.

Another service that we are offering is informational studies. This is designed for early-stage non-binding studies. It’s meant to help customers and developers assess feasibility of their projects before they commit. The ultimate goal is to reduce late-stage dropouts. We’ll see how that works out in practice, but this is something that we have in our cluster.

And finally, we are introducing some financial incentives, basically for dropping out after the study has started. Again, we are hoping that enforces the better use of our resources.

Now while the cluster study approach is designed to improve efficiency and reduce repetitive work, it does come with its own set of challenges, as we heard earlier, for both us, the utility, and the interconnecting customer.

Next slide, please.

So even though -- the one down here -- so even though DWP isn't under FERC jurisdiction, we still follow FERC pro forma process for large interconnection process, and we adhere to FERC's timeline for this process. Now, with our revised cluster process, we have added some extra layers of accountability, which include new posting requirements to our OASIS and reporting obligation to our board, especially around study completion time and if there's any delays.

It's worth noting that we have been handling interconnection using serial process for over 20 years. So moving to cluster-based approach is a big shift for us. It's going to take training and additional resources to make this transition work for us, and right now we are facing a very steep learning curve and our staff are still building expertise. And we are also planning to fully transition to FERC order 2023 cluster process within the next two to three years.

One of the biggest challenges that we have faced, I mentioned, is -- and I’m sure that we will continue to face is complex grid modeling. A lot of time models that we have received, they were incomplete, inaccurate, or they arrived late. Some of them can be addressed with the new cluster, but the accuracy of the models and some other issues might still linger. That really slows down our study process, and that really shines when you study large number of projects at once, especially newer technologies, hybrid storage, advanced inverters that can create a lot of challenge.

Another major issue is availability of capacity. We heard from other panelists. They talked about short-circuit duty, raising towers. We are seeing some of those in our transmission systems. With high level of distributed or renewable generation, we are running out of headroom on our transmission systems in the area that are basically congested. That means we are looking at building new lines, upgrading existing lines, and replacing long-lived equipment like breakers, disconnect switches, transformers.

And the other problem that we are seeing and our customers are seeing is this type of work, it requires outages, and sometimes long-term -- long-time outages. Most of the time, especially during summertime, is really hard to schedule, and in some cases is not feasible, and that really contributes to the delays for getting renewable projects to commercial operation dates.

And finally there is affected system studies. We get these from neighboring utilities and balancing authorities, from NVE, APS, CalISO, SRP. We have vast a transmission system, and we have multiple neighboring utilities. And with this transition, we don't expect that to go away. In fact, because of the recent changes in ITC and PTC, we are expecting to see even more interest in moving those projects forward in a shorter period of time, which requires even more resources from us.

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I wrap up my presentation. I know we are running out of time. These are some of the links for our OASIS for transmission tariffs on our queue posting.

Thank you.

MR. SIMON: Thank you very much.

Brian Biering.

MR. BIERING: Thank you, Sean. Am I coming through okay?

MR. SIMON: Perfectly clear. Thank you.

MR. BIERING: I'm Brian Biering with the American Clean Power Association of California. We represent the interests of utility-scale solar, wind, geothermal storage, and independent transmission developers. I'd like to thank you, Sean, and the rest of the IEPR team, as well as Vice Chair Gunda and Commissioner McAllister for having us today and attempting to account for the perspective of generation storage developers in this iteration of the IEPR.

I'm not going to belabor all of the improvements in the process, but I do want to acknowledge them. Molly's presentation hit on a number of these. The memorandum of understanding and a number of the improvements in the context of creating greater transparency really have been extremely helpful to the generation and storage community since the last iteration of the IEPR. There were -- you know, several years ago, there was a point in time when we were seen being surprised by massive delays in network upgrade development timelines that were jeopardizing projects, and at least at this point I think we have a much better understanding, but as you'll see in my presentation, there is still quite a bit of work to do, particularly on the transmission development and execution side of the equation to really move this forward.

The reason I wanted to make this presentation today was really to flag how network upgrade delays can affect the development of clean energy and storage projects. They can -- you know, for resource adequacy compliance, that's a key demand of the state. It can completely derail a project. You can't sell resource adequacy if you don't have deliverability.

There's also a need to get a handle on maximum import capability. And so these are projects that are outside of the CAISO, they're trying to import into CAISO, and they're completely reliant on network upgrades being developed on time in order to get their maximum import capability allocations and in turn sell resource adequacy.

Network upgrades can also affect the delivery of renewable energy. Even when a project has met its interconnection timelines, it can still face significant hurdles with respect to curtailment on the system. Without those network upgrades, we see that curtailment rise in certain parts of the transmission system.

So really getting a handle on making sure that we're doing everything we possibly can to mitigate transmission delays is really what we wanted to try to focus in on today and provide a few recommendations for the CEC's consideration of this part of the IEPR.

Next slide, please.

So I'm not going to -- I know we're short on time, so I'm not going to spend a lot of time reiterating Molly's slide. This came from the SB 1174 report, which basically was a requirement for the investor-owned utilities report on transmission delays in the context of their RPS plans. This was from the second iteration of those reports, and as you can see in the graph in the far right, the majority of projects are still facing delays or are at least at risk of facing significant delays.

Next slide, please.

We see a lot of different reasons for delays. This slide basically categorizes a number of the reasons that at least PG&E and Edison offered for why they were seeing delays in transmission development.

I do want to highlight one in particular that is in Edison's presentation, which is on the far left, and that is customer action. When we saw this, we were trying to say, was it really the interconnection customers that drove all of these delays? And, you know, while this reporting category as we understand it did account for customer actions -- for example, an interconnection customer can submit a material modification assessment and that can delay network upgrade development when they try to change their project -- what was also accounted for in this category were other actions by, for example, other transmission owners. So for example, Ashkan just flagged that affected systems issues are a key challenge in their private planning process, and that is true across, you know, all of the different balancing authorities that the CAISO has to work with in terms of trying to make sure that when interconnection customers are coming online, that they’re not adversely affecting other systems.

And in that category in particular, there was a significant project that we thought was a good example of this issue. It was the Lugo-Victorville project, which was originally approved in the 2016-17 TPP, and has basically been subject to about 10 years of delays beyond the original in-service development timelines, the most recent of which were largely driven by, as we understand it, the affected systems issues with LADWP. There’s 17 projects behind that affected system, approximately 6.5 gigawatts of nameplate capacity that is being delayed, and roughly 8.8 gigawatts of total generation projects when you account for the projects that are relying on that particular transmission project for reinforcement.

So the point of this slide is really to show that there are a lot of different reasons for delays. There’s not one reason, but really understanding it, creating more transparency in the process, as you’ll see in some of our recommendations, really creating more accountability in the actual construction development part of the process is key for future development.

Next slide, please.

One of the other developments that was implemented since the last IPA was the Transmission Development Forum, I think Neil touched on this a little bit, and Jens did as well, and we agree it is a very helpful process, but what we can see here -- and I'm not going to go through every single project that we've tried to account for -- but what we do see here is that each cycle we're continuing to see delays basically kind of building up on themselves. And so while it's great to get data, more frequent data, regarding the scope of delays, that does help generation and storage developers really kind of account for where their projects are and what risks they may face in terms of actually executing on their power purchase agreements, we really need more in terms of actually getting behind those delays and understanding what's driving those delays, making sure that as between transmission development forum cycles, we're really taking a look at whether there were delays reported in the last cycle and whether those causes of delays have actually been rectified or if we're just continuing to report on more delays.

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So I'm going to touch on a few of these recommendations. I did coordinate with a few of our other panelists and had a few others which we'll put into written comment, but I think that first and foremost -- and I think one of the participants asked a question about this, about data centers and other massive load growth. We are seeing massive load growth, but at the same time, as hopefully you've seen from my previous slides, there's still a lot of work to be done, and we really need to focus on making sure that the utilities are able to prioritize the projects that have already been approved before we're taking on massive new endeavors to, you know, interconnect new load or, you know, even improve new transmission projects, that we're getting on top of the ones that have already been approved.

I think in the context of implementing the memorandum of understanding, that certainly has provided a lot more transparency into the process and has made it easier for developers to identify where on the grid they're more likely to, you know, be able to interconnect or timely interconnect. We are still seeing these ongoing delays, and we believe that it's important in the context of that process of implementing the memorandum of understanding to really start to make more conservative assumptions about in-service deadlines and start to account for the reality that we are still seeing those delays.

As Molly's slide showed earlier, there's still a massive amount of work to be done, and it's our belief that we're not going to see -- you know, we're going to continue to see these delays going forward, and so we really need to be proactive in how we're accounting for those delays in the context of the planning process.

We're also recommending that the CEC and CPUC work together to consider basically the assignment of an independent transmission construction monitor to really focus on the biggest projects, projects that are serving more than a gigawatt of interconnection need. We think that, you know, while there's been great progress in terms of creating more transparency in the system and accounting for delays, we really need to have someone, you know, going through all those lists of causes of delays and really, you know, making sure that someone is watching that and really, you know, holding the transmission developers accountable to dealing with all those different delays.

The other issues that we've noticed is that I think, you know, that PG&E's reports highlighted this -- and I know Edison and San Diego have challenges with it too -- is getting materials online. And this is not at all their fault. You know, here are supply chain issues globally. We are competing -- as someone noted prior, we are competing with other transmission owners across, you know, the United States, globally for major transformers, but we do think that there is opportunity for the state to get ahead of some of those delays and evaluate whether or not, you know, common standards for transmission equipment could be used by all of the investor-owned utilities. So it's not just one standard for each investor-owned utility, but rather all the investor-owned utilities are basically planning their systems with the same type of equipment that perhaps could be purchased, you know, in bulk by the state. So we've encourage the CPUC to look into that.

The other item that we would encourage the transmission owners in particular to do in the context, those that are subject to General Order 131E, so the, you know, investor-owned utilities, is when the project is approved in the transmission planning process, there is often -- years that can go by before permits are filed for that project. And we'd really like to see that timeline shortened so that at least we know what's coming when the utility is planning to file their permit.

I'm going to stop there. I know that was a lot in a short amount of time, and I'll defer to questions. I know we're short on time. Thank you.

MS. NAKAGAWA: Thank you so much, Brian, and all the panelists. We're now going to go to Commissioner McAllister to see if there are any questions from the dais.

COMMISSIONER MCALLISTER: I really want to thank all of you. That was great. Danielle, and John, and Manuel, and Ashkan, and Brian. Those were just really great complimentary presentations.

A lot of complexity here, and we don't have time to dig into it all, but I want to just say thanks and, you know, just make sure that -- well, we know this conversation will continue, and just that we always -- you know, communication is our kind of best weapon here to make progress. And along those lines, you know, we talked earlier about all the collaboration across the agencies and the evolution of that and the sort of deepening acceleration of the iteration amongst the agencies on our various planning and forecasting efforts.

I'm wondering -- I mean, we cannot have, you know, transmission or other balance-of-system issues or process get in the way of accelerated deployment. I think Molly's, you know, message at the beginning of her -- the outset of her presentation is an incredible story, just the accelerated deployment of renewables and storage, and that we've managed to, you know, keep the balance of systems conversation and the availability conversation sort of supporting the build out of supply. Our -- so, you know, in some sense, the more we get the sort of -- the more complexity and sort of the more we try to accelerate, you know, the more little issues or just issues that we're talking about can become bottlenecks.

And I'm wondering, sort of, are there other entities, agencies, you know, local regional governments, other -- you know, Brian, you mentioned some of the collaboration that's happening out there in the industry and with the agencies proposing some independent monitoring, for example. Are there any particular relationships that we could do better sort of deploying or, you know, improving, enhancing, developing, that the agencies could help create some of that accountability you're talking about?

And let's start with Brian.

MR. BIERING: Well, I think that what I would flag is the effective systems issues. And we've seen that across, you know, a number of different projects. I flagged the Lugo-Victorville line as sort of the biggest example. But I think, you know, because the CEC is in a unique position of overseeing both, you know, investor-owned utilities and publicly-owned utilities that operate their own balancing authorities, the CEC, I think, could play an important role in that regard. You know, the effected systems issues from our perspective are really important to grapple with and oftentimes come up very late in the interconnection process, which can lead to material delays, so --

COMMISSIONER MCALLISTER: Are these fundamentally jurisdictional or sort of just left-hand, right-hand, or kind of what are the relationships that could sort of solve that, create more fluidity or more synergy?

MR. BIERING: I think, you know, I mean, from my perspective, it's getting more information earlier in the process about when -- you know, when there are potential affected systems issues. I think every time I've seen it come up and, you know, delay a project, it's always been at the end of the process. So I think the CEC, while it doesn't, you know, directly oversee balancing authorities, it is nevertheless responsible, for example, taking in integrated resources plans and creating more of that holistic view of the system.

COMMISSIONER MCALLISTER: Okay. I'm interested in, Manuel, your perspective on that as -- or actually both IOU and POU, sort of Manuel on the IOU side and Ashkan on the DWP side, sort of maybe start with DWP, sort of how does -- what is it -- how do you react to what Brian's saying in terms of just challenges of deliverability and your surrounding -- your neighbors as balancing authorities?

MR. NASSIRI: Yeah. That's a really good point that Brian brought up, Commissioner. Unfortunately, a lot of developers, they come to us very late, so even that they know that they have the LGI in hand few years in advance before the COD, last thing on their checklist is, oh, check with the affected system, you know, the neighboring utility to see if they have any issue.

As you know, these studies, they take a long time, and we have a number of those. So when they start reaching out to us one by one towards the end, it creates this bottleneck, unfortunately. And because of the sheer number of these requests, we won't be able to respond quickly. And --

COMMISSIONER MCALLISTER: And --

MR. NASSIRI: -- in some cases --

COMMISSIONER MCALLISTER: Sorry. Go ahead. Finish your thought.

MR. NASSIRI: Yeah. I'm sorry.

In some cases, if we can determine that there is no negative impact, we would not even do a study and we move forward. But in cases that we anticipate a negative impact or a loop flow or some other issues, then we do move to a study and that can potentially lead to delays for the projects.

COMMISSIONER MCALLISTER: Okay. Interesting.

MR. AVENDANO: Hello. Can you still hear me?

COMMISSIONER MCALLISTER: Yes. Go ahead, Manuel

MR. AVENDANO: Yes. Yeah. I think from my perspective, I think with that particular project, I think the lack of oversight or central agency overseeing the collaboration has not been the biggest challenge. I think the biggest challenge with this particular project has been its complexity involving two utilities, right? I think there’s opportunities to harmonize the effective systems of both balancing authorities, DWPs and the CAISOs as well. But when it comes to project execution, there has been, you know, a multitude of challenges as well, right? It’s coordinating, scheduling the audits necessary to do work on both sides, right? It is a shift in our priorities as well. We have transformer failures that our partners in DWP have to, you know, reprioritize and impact their ability to work on these as well.

So there’s been -- yeah, this is not an excuse, right? It’s been taking a long time. But I think in this particular instance, there has been more challenges on the execution phase. And yeah, if I think about it, it’s us, it’s SE working with a utility that happens to be as well its own balancing authority, right? So yeah, can the CAISO get more involved from a balancing authority to another balancing authority? Sure. There’s I think always room for improvement.

COMMISSIONER MCALLISTER: Okay. Interesting. But I guess just to be clear, this is not a question of sort of one developer sort of -- I don’t know, I guess I just want to make sure there’s no gaming going on. Like, if we can connect some dots and sort of improve transparency to, you know, speed things up, happy to try to do that, or, you know, working with CAISO and what that would look like. Anyway I really appreciate y'all bringing it up.

Does anybody else want to comment on that? Probably Danielle, taking the CAISO's name in vain.

MR. NASSIRI: If I can add one more. So my first response was pretty generic about the affected system as a whole and the timing as when they come to us.

Regarding this particular issue, Manuel mentioned it's a failure of a bank at Sylmar, and that makes the taking outage on Victor Villalobos line pretty much impossible. We are trying to find work-arounds and see how we can improve that line. There are several towers that needs to be raised, there are a number of 500 KV breakers that needs to be replaced, and that requires outage. So we are trying to figure out ways around that outage when we have that bank out and the tie is already overloaded so we can't really take additional outage on the tie between CalISO and DWP.

COMMISSIONER MCALLISTER: Okay. I understand. Great. Well, I could ask a few more questions, but I'm going to say, Sean, we should probably end it there because we're already pretty far behind.

But yeah, really appreciate everyone's insight. You know, Vice Chair Gunda would also emphasize that. And we appreciate all your effort there and all of your expertise. So thanks a lot.

MR. BIERING: Thank you.

MR. AVEDANDO: Thank you.

Great. Back to you, Sean. Thanks.

MS. NAKAGAWA: All right. Well, we normally get audience Q&A. It looks like the one question we have is a holdover from our first panel, and we also just have a comment, so we are going to go on to our last panel.

So I'm happy to introduce Matt Coldwell. He'll be leading our panel discussion on distribution level interconnection and energization. Matt is the Manager of the Distribution Planning Branch within the California Public Utilities Commission. Over to you, Matt.

MR. COLDWELL: All right. Thank you. So yeah, as Sandra said, my name is Matt Coldwell. I work in the Energy Division at the CPUC. Specifically I oversee the Distribution Planning Branch, where a lot of the efforts -- well, actually all the efforts that I'm going to talk about today are conducted, so I just want a quick thanks to Vice Chair Gunda and Commissioner McAllister, and of course the CEC staff for having the CPUC here today.

I provided a presentation back in a 2023 IEPR workshop that was also on energization and interconnection, and so my goal today is really to provide a high-level overview and update of the numerous efforts that the CPUC has undertaken and continues to undertake to make improvements to both the energization and interconnection process -- the distribution energization interconnection processes. So really over the last couple of years, energization has been more of our focus, and there are reasons for that that I'll get into.

So I do have several slides, and given the time crunch I'm going to try to move through them as quickly as I possibly can.

So next slide.

So I was glad to hear Hannah actually touch on this early this morning -- or I guess, no, early this afternoon -- really just differentiating between the interconnection and the energization process. I feel like this has been my mantra for the past few years is, you know, these terms can be used interchangeably, but from a -- you know, from a kind of process regulatory standpoint, they are very different.

So interconnection is a term used for connecting generation and energy storage to the distribution system, and there are specific tariffs that govern that. So Rule 21 is the CPUC jurisdictional tariff, and then the Wholesale Distribution Access Tariff, or WDAT for short, is FERC jurisdictional. These are still projects that are connecting at the distribution system but are wholesale projects.

The energization process specifically refers to the connection of customer loans, and so that could be any type of customer load-building, EV charging station, et cetera, and there are a variety of rules that govern energization here. And I’m actually going to get to that on the next slide.

So next slide, please.

So here are sort of the different rules that apply to different energization projects, and depending on the project, it’ll trigger some of these rules, or a few of these rules. So really Rules 15 and 16 are the primary energization rules that are within CPUC’s jurisdiction. So Rule 16 are service extensions, and that basically covers the equipment that’s connecting the customer to the nearest utility distribution line. The costs are covered by ratepayers through an allowance. Depending on the project, there could be some customer-associated costs there too.

Rule 15 is an extension kind of Rule 16. It covers, you know, from the service connection up to the distribution system, and those costs can also be covered by ratepayers through an allowance, and then partly by the customer. It just really kind of depends on the project.

Rule 2 is special facilities. These are sort of non-standard equipment installs that a customer is requesting, and these are costs that are covered directly by the customer.

And then Rules 29 and 45 are specific EV infrastructure rules that CPUC established a few years ago. This covers utility side-of-the-meter service and distribution service or distribution facilities, and those costs are mostly covered by ratepayers.

Next slide.

Okay. So this is -- sorry. My computer is having a hard time loading up here.

So the Rule 21, the interconnection process, is a much more -- has a much longer history at least of improvements to the process than on the energization side. I'm not going to walk through all this, but you can see over the last few decades there's been quite a bit of effort to the stakeholder process of making improvements to distribution interconnection.

And I'll just note these green boxes here at the far right indicating that the proceeding that oversaw a lot of this work, this R170707, just recently closed late in 2024, and we do have a new interconnection OIR actually on the CPUC voting meeting this week, and I'll talk a little bit more about that in a second.

So next slide.

Okay.

As I mentioned, a lot of our focus has been on energization over the last couple of years. In large part that’s due to a couple of pieces of legislation that were signed into law back in 2023. So these bills came in response to reported significant energization delays by several customers throughout the state, and so this is a high-level summary of the bill. There’s lots of components to each of these, you know, that would take up presentation in and of itself, but generally this is called the Powering Up California Act, and it directed the CPUC and the large investor-owned utilities to make various improvements to existing energization and distribution planning processes.

And so SB 410 directed the CPUC to define and establish energization -- target energization time periods and develop various reporting requirements to the CPUC that the large IOUs need to, you know, report to us. It also directed the CPUC and the IOUs to make a variety of improvements to the existing distribution planning process, and also provided large IOUs an option if they so choose to use it to request the use of a rate-making mechanism for energization-related costs above their existing authorization, and SB50 was a complementary bill that required us to determine criteria for timely electric service as well as establishing annual reporting requirements.

Next slide.

So in response to that, we had existing proceedings but also launched new proceedings. That's really put us in a position, you know, to ensure that needed infrastructure is available in the future for customer energization needs. And so across these four -- well actually across the three on the left is really the implementation of the SB 410 and AB 50. So distribution planning process improvements have been handled in our high DER proceeding. We've launched a new energization process improvement proceeding that established the timelines and the reporting requirements. And then on the cost recovery mechanism, both PG&E and SDGE filed applications to develop a rate-making mechanism to record and recover energization-related costs. I'm not going to talk too much about that today.

And then I've just added this large load energization proceeding here, so -- and I'm going to talk briefly about this at the end of the presentation. It's not specific to distribution. It's actually a new closed role at PG&E service territory for retail transmission consumers. So I'll talk a little bit more about that at the end of the presentation.

So moving on. Next slide.

I'm going to get into distribution energization first.

And so next slide.

So timely energization. Why is this important? Well it's important for a lot of reasons, but it's really critical to California's economy and policy achievement. And so there are -- have been over the last few years significant and legitimate concerns about energization delays across all of California's major economic sectors, and so it hasn't been specific to, you know, large EV charging stations or building electrification. I think there's been a lot of concern, you know, across these sectors. We've heard from stakeholders about, you know, the need to satisfy California's policies -- decarbonization policies through electrification and their ability to do that, you know, with these types of energization delays, as well as just the presidential projects that have experienced long lead time and capacity -- infrastructure and capacity needs and just creating a delayed energization.

Go to the next slide.

So as I mentioned, we launched energization OIR in early 2024. And, you know, the primary directives from the two bills were addressed in phase one of this proceeding. We're developing the energization timelines and reporting requirements so we have, you know, in --

we'll get to the decision here in a second.

So we have completed some of that work. There are a couple of ongoing efforts. We're working on a -- what's referred to as a bridging solution specifically flexible service connections, and that's ongoing work that we're hoping to be able to make some movement on here in the near-future.

And then PG&E's SB 410 cost cap increase. So it's a reference to the ratemaking mechanism that they requested for energization-related costs that was part of their -- part of their GRC originally, and then they filed a motion to increase the caps that were set, and that's being handled within the energization OIR as well.

Next slide.

Okay. So the energization timelines decision.

So in September 2024, the CPUC approved decision 24-09-020. So there's several elements. So this decision implemented several elements of the Powering Up Californians Act.

I could spend a lot of time on this slide, but for the sake of time I'm going to try to move through this pretty quickly. So essentially the decision aims to expedite the process for connecting customers to the electric grid. It provides some level of transparency to the energization process. It adopts timelines based on the utility's historic energization data, and it's intended to support early -- so I've heard this a couple of times today -- so early engagement between the customer and the utility to coordinate project development. And so that's kind of a key component here.

And then just to be clear here the timelines apply to the large IOU. So Edison, San Diego Gas and Electric and PG&E.

Next slide.

So part of the decision established what the energization process actually is. So it identified eight steps and identified, you know, what those steps are, and then who shares responsibility for each of those steps.

So you can see each of these steps aren't specific to the utility. There is dependencies on the customers to be able to provide appropriate information documentation to the utility so they can process their energization application. I think some of these steps have some co-dependencies, but this is a high-level description of what the energization process looks like, what each step is, and who sort of has responsibility for each step.

Next slide.

As I mentioned, the decision established timelines for energization timelines. And so what we have here are -- we established average and maximum timelines.

So these are in calendar days, right? Yes.

So essentially it's 125 business days which is consistent with the EV charging energization rules. Those are business days, so what we're seeing here are calendar days.

So essentially for rules 15 and 16 projects and projects that utilize both rules as well as the EV infrastructure rules, the average timeline for utilities to meet or beat is about 182 days, and then the maximum timelines as you can see what they are there for each of those. And as I mentioned, it's consistent with what was adopted previously in electric rules 29/45, but it is based on historical data. So these are achievable timelines on an average.

So next slide.

Okay. So we also established -- these aren't -- I mean, these are timelines but for upstream capacity projects, so you can have an energization project that's requesting, you know, a significant amount of load and those projects can trigger upstream capacity projects that are beyond what's covered in the energization rules. These are really -- you know, some of the long lead time projects that we've heard about are typically because they do trigger one of these types of capacity upgrades.

So we've also established the maximum timelines for these. These are -- you know, we're not holding the utilities to these numbers yet because we had kind of a lack of data to be able to establish firm timelines, but as we go forward and we get -- we collect more data from the utilities, you know, we intend to change them.

Next slide.

As I mentioned, you know, one thing that we're doing now is flexible service connections, and so we consider this a bridge-to-wire solution for customers who cannot currently receive their fully requested capacity in a timely manner.

Just in short, you know, the IOs would be able -- they are already able are already able to offer a service we're calling limited load profiles. It essentially outlines certain load limits that a customer must adhere to during certain times of the day in the year when the local distribution infrastructure is constrained. So in other words, if a customer is triggering a capacity need because, you know, during the peak times of the year the system's constrained, if they can throttle their energy demands during those specific times, they can -- they're able to be able to get connected to the system earlier until such time their full load request is able to be served through future capacity investments.

And so that's being -- so we're considering this in two proceedings. So the energization OIR is having a discussion about firm capacity load profiles and then the high DER proceeding is building a record on kind of the next evolution of that being able to develop more dynamic load profiles to customers.

And so speaking of the high DER proceeding, why don’t we move to the next slide -- the next one after this -- into distribution planning improvements.

And so the primary directives of SB 410 and AB 50 that were addressed in the high DER proceeding focused on improvements to the existing distribution planning process. So essentially the existing process -- it’s, you know, it’s taking a historic change in load growth so a lot of new load through electrification policies and economically -- and economic development and trying to, you know, build for that using a fairly reactive and conservative distribution planning process, meaning that distribution planning typically is handled by utility, knowing they’re seeing the service requests from their customers and being able to plan that, as opposed to being able to anticipate future service requests based on policies or otherwise. And so this can lead to long time -- long lead time energization delays.

The improved process that we’re trying to work our way to is to still take that historical change in load growth but utilize a more proactive and transparent and flexible distribution planning process that plans for loads a bit more proactively with the goal, of course, of having available capacity online for timely energization in the future.

So next slide.

So in October of 2024, within the high DER proceeding D24-10-03 was approved, and directs the large IUs to make a variety of different improvements to the existing distribution planning process.

So just at a high level, I'm not going to really -- I won't walk through these, but you can see here some of the categories of improvement that we identified in decision and the IOUs are currently implementing. So, you know, enhanced forecasting so using more scenarios within distribution planning. I think I just do want to highlight this new and improved data one here with pending loads.

And so as I mentioned, utilities generally plan, you know, rightfully to their known loads so they, you know, the customers that they know they have to serve, and they are working on developing a new pending loads category that tries to anticipate where load growth and what type of load growth may be happening in the future throughout their service territory and to be able to plan for that more proactively. So that's an ongoing -- it's ongoing work that's currently happening within the proceeding.

Next slide.

This is illustrative. I'm certainly not going to talk through this, but I just wanted to highlight, you know, from the previous slide, you know, what all of the actions actually are that were directed within the -- in the decision from October of last year. So these are all things that we've required the utilities to do in the name of improving the distribution planning process.

So next slide.

All right. So let's move from distribution energization to interconnection.

So next slide.

So as I mentioned, there's a new interconnection OIR that mailed last week I guess, and is on the mission voting meeting agenda for this week. So I'll caveat that this hasn't been approved yet. You know, if it is approved it would, you know, be on Thursday this week, which I can't say too much about it at this point. I'm just going to talk just a little bit about it.

And then actually let me just go ahead and jump to the next slide.

So here's some of the preliminary topics that we want to address, you know, within this new proceeding. These are based on, you know, ongoing stakeholder discussions that we have and -- you know, so there's still quite a few issues out there that weren't addressed in the previous proceeding. And so I just wanted to give folks a flavor of what we'll be talking about in this -- or some of the issues that we'll be discussing in the new proceeding.

So next slide.

One thing we have done that was directed from a decision in the previous decision, and this has been over the last couple of years, is developing limited generation profiles, that limited generation profile option in the rule 21 process. So this allows export-limited interconnection without time and cost of distribution upgrades where the, you know, the local system does have capacity constraints. That's similar to what I was talking about earlier on the load side. This is just for generation. So if the customer is willing to throttle back their generation during certain times of the day in the year, they can avoid certain distribution upgrade costs with the goal of also trying to speed along the interconnection process.

And so the export limits are based on the ICA values at a specific interconnection location. So this was developed through a stakeholder working group and workshop process through -- over 2021 through 2023, and then adopted in a resolution in March of last year, and then implementation actually just became effective last month in July.

Next slide.

Okay. So transmission energization. So this is going to be quick.

Next slide.

So yeah. So this isn't -- you know, the panel here is talking about distribution-related issues, but I went into this and this is energization related.

And so back in November of 2024, PG&E submitted an application proposing this new Electric Rule 30 tariff. The goal is creating a standardized process essentially to connect transmission level customers seeking retail service.

And so this table is intended to show where Rule 30 sort of fits in both jurisdictionally as well as, you know, at which voltage level.

So as you can see, on the transmission side there currently exists no rule that governs retail transmission customers, such as there is on the distribution side with rules 15 and 16. So this is that -- this is the gap that this application is seeking to fill.

So next slide.

PG&E submitted a motion for interim implementation of the rule back in January, and then last month the CPUC approved a decision that partly grants PG&E's motion for interim implementation of Rule 30. Just the key points of the PD is it authorizes PG&E to begin processing transmission level requests using the approved form agreements, and requires the transmission level customer to provide the entire costs of certain facilities and provide PG&E a pre-funded loan for some of the Type 4 facilities which are the networked facilities, it did decline to approve any repayments of the pre-funded loan for facility Type 4s and it doesn't guarantee any repayment of 100 percent of the loan.

Essentially here what we did is we, you know, we didn't -- through the interim implementation didn't establish any rate recovery authorization, and that will be further considered as part of the application, which is ongoing. So this just grants some limited ability for PG&E to use the Rule 30 in the interim basis until we produce a decision on the application itself.

So next slide.

Oh. And that was it. So hopefully I moved quickly enough and now happy to stick around and answer any questions.

MS. NAKAGAWA: All right. Thank you so much, Matt.

We're going to turn it over to Philip Kobernick.

Philip is the Associate Director of Energy Programs of Peninsula Clean Energy.

MR. KOBERNICK: Hi everyone. Am I coming through all right?

MS. NAKAGAWA: I can hear you loud and clear. Yep.

MR. KOBERNICK: Wonderful. Thank you. Great presentation so far. Good afternoon, everybody. Thanks for having me.

I'm Philip Kobernick with Peninsula Clean Energy. If you're not familiar with us we are a community choice aggregator, or CCA, for San Mateo County and the town of Los Panos, the City of Los Panos in Merced County.

So we heard a lot about challenges of service upgrades today, and to quickly really achieve deep decarbonization on an accelerated time scale for buildings and transportations, we're really going to need to minimize the impact of service upgrades.

And so the way that we do that while serving our customers and their efforts to decarbonize is to heavily focus on right-sized strategies, and so I'm going to be talking about that with my few minutes today and how we're implementing it across our programs.

Okay. Next slide, please.

All right. So if you are a homeowner and you've electrified your home yourself or if you've worked with folks who have done this, there's a lot of social encouragement let's just say to, you know, first start by doing a service upgrade. Before you do anything, else get your house up to 200 amps if you're at 100 amps or maybe go to 400 amps if you're at 200 amps. There's a lot of encouragement and also a lot of misinformation frankly on how much load residential customers really need to fully electrify their homes.

And so there's a few snippets here from all across -- you know, headlines from all across the space about what it means to really to upgrade your panel and why lots of folks think that that's where they need to start. But what I'll be talking about today are lots of strategies that show you do not need to do a service upgrade if you're electrifying, you know, a single-family home for -- to go to electrify.

All right. Next slide, please.

So instead of pulling the we need to service upgrade everywhere lever, an alternative approach would be to implement right-sizing or right-sized strategies across the board. And so what that means is you first identify what you actually need. And so what I'm mostly going to be talking about today is single family electrification, but it's also relative for other sectors like EV charging and multi-family segments and other commercial segments. I'll touch on kind of all those, but generally speaking what do you need? Like, what is the actual energy usage that electrification will be required of you? And then start with what you already got, with let's use the grid we already have first essentially. And so for most folks that -- well, I'll get into this in a moment, but that's using what you already have in your home. 100 amps is sufficient for most people. And then you only really upsize when you need to. So that's, you know, of course back-of-the-meter stuff but then, you know, upgrades down the line too, because all this sort of cascades upward.

And so not everybody can avoid service upgrades there's certainly a lot of scenarios in which service upgrades are going to be needed. In my mind, I'm thinking right now of a lot of fleet facilities too where you mostly have very limited power and you're having to kind of significantly increase power to handle fleet electrification, but even in those instances where you are going to have to do a service upgrade, when you right-size your infrastructure -- in this case the EV charging needs -- you're minimizing the impact significantly upstream for what kind of front-of-the-meter resources would be needed to be upgraded to handle those types of projects.

So it's really important to avoid service upgrades, of course, but then also minimize impacts for distribution utilities and ratepayers across the board when these major systems need to get upgraded.

Okay. Next slide, please.

Now, right-sizing as a strategy is really important for saving money. I mean, there's a lot of folks that focus on the big kind of behind-the-meter upgrades that need to happen -- I'm sorry, the big front-of-the-meter upgrades that need to happen, and that's really important too. But it also saves directly customers when they're upgrading in their properties too. So by using more affordable solutions, right-sized technologies, that not only helps the distribution utility, but it also helps just everyday customers in their homes or for properties that are doing lots of EV charging upgrades to electrify more affordably.

And these are some kind of roundabout PCE numbers that we looked at across the state for the real dollars that we've seen by taking our savings from our programs either as single families or a multifamily, and then thinking about how that can cascade across the state through a right-sized approach.

Okay. Next slide, please.

And the good news is that there is a lot of tools at our disposal to do this. So electrification is becoming easier and easier and easier, and there's a lot of ways to again use the power that we have now while fully moving off of fossil fuels.

So these include circuit controllers, pausers, throttlers, things like that. I've included a few examples here. The one on the top-right is like a -- the top two and actually are like dryer splitters kind of. So imagine you have your electric car and your dryer -- your electric dryer in this case plugged in. They'll know to only turn on one at the same time, right, so that you're not overloading a circuit there. These are really affordable little widgets to help you do that.

I've included some other examples. Simple switch, the one on the bottom left is a load controller from RVE called a DCC9 unit. These are all just ways of pausing things to use, you know, the capacity that you have.

Smart panels and breakers, like span up above. These are also really, you know, interesting opportunities to isolate loads, really stretch power capacity. And then a big area that we focus on at Peninsula Clean Energy across our multiple programs are using 120-volt equipment. So these are low power or low voltage equipment that can handle customers' needs especially in, you know, again single family homes being a fine candidate for a lot of these solutions. And they help folks electrify more quickly and easily. Again, you're using the plugs that you already have to electrify.

And so I have a few examples here. Our gradient on the top left there is an HVAC -- a heat pump HVAC unit that runs on 120-volt. There's on the top right Channing Street, which has a battery integrated 120-volt range. So again, you're plugging in not to a 240-volt in your kitchen but a 120-volt, which a lot of people already have. And then boom, you've got an electrified induction range with just the -- you know, a regular plug.

120-volt EV charging on the bottom left is another major area of focus that we look at. We've studied this extensively in our program, and think that this is actually a really great solution for nearly everybody. We've done commute studies that show that over 90 percent of regular drivers can meet their everyday needs if they have a place to plug in every day. That overnight charging provides 50 miles of recharge, and is a great solution for everybody. And in fact, the CEC recently added a level one charging into its Communities in Charge Program. Part of the flagship state incentives to get EV charging into multifamily. So great solutions there.

And then I'm now belaboring the 120 voltage point a lot here, but also great for heat pump water heaters. There's a number of solutions in which low voltage equipment like this or 120-volt equipment really, really helps people electrify quickly with what the capacity that they already have.

And I'll also add one thing I didn't include in this slide also, but PCE is also getting started a lot on virtual power plants. It's not really like a service upgrade kind of avoidance strategy strictly like we're talking about here, but what we're doing on, you know, VPPs and load shaping just generally speaking helps the larger grid, right? You know, freeing up capacity constraints and kind of being better stewards of our larger grid which is another big area of focus that we're working on. Okay next slide please.

So we've done a lot of challenges. I'm an optimist and I like to also reframe the question: what would it look like if we got it right? So if we're going to achieve rapid decarbonization of buildings and transportation mostly with the grid we have now, what does that look like?

And fortunately we have some good examples from our own PCE programs that I'll call out here.

So next slide, please.

All right. Right-sizing in action. So I know some of this is a little abstract. Here are some real data points.

So a few years ago we fully electrified nine low-income homes in San Mateo County, and here's an example of one of them. Actually none of these homes did service upgrades. So all nine homes we electrified fully with zero service upgrades, and a few of them, five of them in total, had 100-amp service. So comprehensive electrification on the service capacity that folks already have significant avoided cost on a per home basis.

And on the right is a rental apartment in San Mateo where we helped install 63 level one smart outlets without a service upgrade. So 63 folks now have a reliable place to plug in in their assigned parking there so they know that their next car can be an EV because we were able to do that with no service upgrade. So it happened within weeks, not within months, and significant avoided costs compared to what they would have spent if they were looking at more expensive commercial level two charging and if that required a service upgrade with larger distribution upgrade assets.

Okay. Next slide.

So hot off the presses is a new report that we are just releasing today on that whole home study that I mentioned. So we fully electrified again nine homes with zero service upgrades. Most of those have 100-amp service, and there's a lot of great takeaways from this report but one of the major ones is that all -- you know, these customers on average had about 20 percent bill savings. So most people are saving money after they electrify, which is really critical. And then we're taking these reports and then utilizing them in our direct install program as well.

Okay. I think I've got one or two more slides.

Next slide, please.

The other thing about right sizing is it helps you go really, really big. So in our EV charging program, we've installed over 2,000 chargers in the community. A lot of them are level one, and right now we have some of the largest multi-family EV charging projects in the country that are happening right now, and a lot of that is because we're using level one smart outlets which are more affordable again and quicker to install.

And one of these is a 200 plus charging project happening at the rental apartment in south San Francisco. It's going to be one for every single parking lot, so -- or every single parking space rather. So once that project is done all these renters are going to have access to EV charging, and they never have to do it again. So that's kind of what this strategy helps us do, is by getting the costs down, reducing the impact overall, it lets people go really big for these types of decarbonization projects.

Okay. Last slide, and I think that might be it for me.

Thank you. We have lots of great resources on our website. I'm also happy to answer questions. Thanks so much.

MS. NAKAGAWA: Okay. Thanks, Philip. We're now going to bring on Bill. Bill is the senior manager of electric planning modernization with PG&E, and I just do want to note we are running a bit behind schedule so if we are able to move a bit quicker through these presentations that'll help us make up some time.

Over to you, Bill.

MR. PETER: Okay. Yes. So I'm going to talk about accelerating distribution interconnection and energization. I'm going to focus just given time mostly on the energization aspects of it and some of the things we're doing to really accelerate loads.

So if we move on to the next slide.

So really we view this as, like, really an opportunity here, where we're having a lot of a need to accelerate our energization of load for a high-electrification future and if we can bring that load, and we can scale up our delivery of customer energizations, that's going to help transition the California economy, but it’s also going to, like, improve affordability if done right for our customers because now we’re bringing on a lot more load to the system.

So thinking kind of from the perspective of like where were we, what are we working on now, and where are we going forward. I think, you know, a lot of the foundation work was actually about transparency, right? So we first had to kind of share with customers what’s happening on the distribution grid? Where is their hosting capacity? Where is their grid needs? Where are we doing our distribution investments?

Then we kind of moved towards how do we accelerate those customer interconnections? How are we doing in terms of actually delivering on those projects that we have planned? How do we bring customer input in earlier some of that proactive planning that we heard Matt Coldwell mention before to bring that into our planning and into our energization planning?

And then looking forward, right, how do we start to leverage customer flexibility as we see, you know, more and more both on the generation and the load side, more flexibility from distributed energy resources and other sources, how do we make sure we leverage that to both accelerate customer timelines and also drive improved affordability by reducing the need for infrastructure upgrades?

And so with all that lens, kind of moving from a deferral to more of an acceleration and scaling up mindset, as well as making sure we really stay focused on the customer outcomes, which is really about timeliness and affordability.

Okay. So next slide.

So first on that, you know, transparency slide one of the big things we've done is we have a Grid Resource Integration Portal, which is where we provide customers really visibility into our distribution system. This is where we provide that host ICA, that hosting capacity data. It's where we provide what our plans are for the system, where the needs are. And we've done a lot of investments that we can actually build this platform for future use cases, and to handle the fact that we're seeing increased use of this portal. We've had over a 600 percent increase in customer usage. So it's clear that customers want this type of information, and we're working to improve that provision of that information for our customers.

Next slide.

Then we talked a little bit about, like, that need to do proactive. So we improved, you know, our transparency in terms of providing information outwards, but we also need to collect information and start using it.

So we filed a community engagement plan which will do outreach to customers and cities and communities to collect their kind of pro -- you know, their future plans for electrification. So, you know, this is before they're ready to submit actual load applications. You know, what are you going to do a few years out, five years out. Start to get ahead of that, collect that information, and then bring that into our actual planning process. So by the time you submit that load application, we're already well aware of it and we've already started to think because a lot of this capacity work is multi-year in nature. So we really need to get ahead of this growing electrification need that's coming.

Next slide.

So then that's that medium term trying to get ahead, that proactive planning, but we also want to look long term, right? So we're undertaking an electrification impact study where we're going to look at really how to achieve a high-electrification future all the way out through 2040.

A couple things to call out here. You know, first we're going to we're going to look at the secondary system and the primary distribution system. We just kind of heard talk about how the importance of that secondary system and actually thinking through what the impacts and how to best do that affordably and quickly for customers on the electrification side. We're also going to do scenarios, right? So like how to look at that future under a variety of different scenarios and plan with more flexibility in the future.

We're also going to look at how to improve, you know, the equity and make sure we're considering that we're having equitable outcomes for customers as well as, you know, again that load flexibility. How can we we're able to, you know, bring more load flexibility and leverage that load flexibility? How can we leverage that to both accelerate and make more affordable the infrastructure investments we need?

And then, you know distinguishing here a little bit between, like, how the distribution system, you know, that secondary and that customer individual planning works versus, you know, our top system bounds approach. So kind of building from the bottoms up, and really think through how can we leverage that to be more efficient with our investments and what's really needed for our customers.

So next slide.

So this was touched on earlier, so I'll keep this short, but yes we've launched -- I do want to bring up, like, a generation aspect. We have launched our limited generation profile where we're basically empowering DERs to leverage their flexibility to operate within grid constraints, really to minimize the need for distribution grid upgrades. That way they can accelerate their interconnection and reduce the amount of costs associated with that. And again, that GRIP portal I mentioned before is where customers can get that information and then use that in the your projects portal, it's called, as they submit their interconnection requests.

And then next slide.

So that's on the generation side. On the load side, so actually what we're really focused on is on that intake process. We've done a lot of work to make work on that iterative part with customers to make more efficient back and forth on that initial intake part of when customers want to get the energized. What we're also looking to do is start using our ICA data to basically allow it to flag for customers very early on if they have capacity issues. What we don't want is customers submitting requests and then finding out, you know, after engineering review a couple months later that there's actually an upstream capacity issue. So we want to bring that early on and let them know.

And usually -- or often, I should say -- if we work iteratively with the customers we can find solutions. We can find some of those bridging solutions we discussed about. So it’s about being able to iterate, but doing it early and being able to really provide a customer oriented solution.

And then I think the last slide -- if you can go to the next slide.

So those are a lot of the ongoing efforts we have. Stepping back for a second, like, what’s the key challenge ahead? It’s really about this need to scale up the delivery of our capacity for our customers. For a high-electrification future, we’re going to have to start delivering on an accelerated scale but also a much broader scale just the amount of demand that we see.

And so for that, this is talked a little bit earlier, we’ve set up a capacity delivery center to really get a sense of how do we prepare for that scaling up. A big part of that is readiness work. So these are multi-year projects. So in order for us to be ready for that increased energization needs that are three, four years out, we really need to be getting these projects, the sourcing, the permitting, the design work done on these projects now. So it’s about monitoring that and accelerating wherever we see bottlenecks, and really starting to really have a long -- like, a lean production system model that we can take a project from that initial stage where we identify that need as proactively as possible, and then be efficient and drive that through, thinking through multi-years ahead to deliver for those customers. And if we can do that, we'll help facilitate that transition for the California economy in a timely manner, and then also as we bring that load on improve affordability.

So thank you for the opportunity to speak. That was -- that's it on my end. Thank you.

MS. NAKAGAWA: Thank you so much, Bill.

We're going to turn it over to Jigar Shah. Jigar is the Director of Energy Services at Electrify America.

MR. SHAH: Good afternoon and thank you for an opportunity to speak here. I'm the Director of Energy Services -- next slide -- at Electrify America.

And so Electrify America operates one of the largest DC fast charging networks in North America. We have over a thousand locations across over 250 distinct utilities and around 4,700 DC -- individual DC fast chargers. They're all rated at 150 kilowatts or above. The majority are 350-kilowatts-plus capable in terms of power delivery to capable EVs.

Next slide.

And in addition to of course our DC fast-charging infrastructure rollout, we also have the largest rollout of on-site behind-the-meter energy storage coupled with DC fast charging across the nation with over 170 locations having again behind-the-meter coupled energy storage for a peak load management perspective as well as a capacity perspective. And that's going to be a big focus of my talk today, and thinking about how, you know, the IEPR program and the various rules can work cohesively to enable DERs to improve energization timelines in a more cohesive manner.

Next slide.

And I thought I'd start with actually kind of a design of how one of our charging stations looks, and this is a conceptual design of course. As you see here, kind of starting out from the left-hand side, a battery energy storage system that can be rated around two megawatts or so. Of course, a switchboard, a transformer where a 480-volt or secondary voltages come in followed by the EV chargers. And so you what you see there is 12 individual power cabinets that are rated at 360 kilowatts DC output each that are shared across two chargers, and that's around 24 chargers total there.

And so from an interconnected load perspective, this can deliver around 4.3 megawatts of peak demand from a DC perspective, and an interconnected basis 4.6 megawatts AC, which would exceed the secondary voltage capabilities of most of the California utilities in a single service. And so the energy storage of two megawatts there would be critical to bring this down into the secondary voltage level. And this is an example of how smart DER deployment can cost-effectively avoid for example medium voltage service and deploy more charging infrastructure now.

Next slide, please.

In thinking about the various rules that we've discussed so far in a panel, right, how do they all kind of interact? And kind of bottom line up front is that, you know, there's opportunities for synergies when you're thinking about energization timelines, the role of energy storage and solar, in terms of meeting the challenges that we have as a state and a nation to have synergies between all these different rules and how they interact.

Specifically kind of starting out here from the from the top line 15 for line extensions, these often ignore the impact of separate Rule 21 energy storage or solar projects even if they're all being built at once. We've had cases where, you know, we'll get capacity results that don't account for the DER side because different departments are not talking to each other, and that requires additional handholding as well as delays.

And similarly, under the Rule 15 side of things projects may be stalled because non-EV related Rule 15 projects actually get priority in a sense because Rule 15 and Rule 16 are so to speak standard and don't require special treatment for Rule 29 and 45. And so we've run into quite a few projects where we're being told in order for those to move forward you might want to forfeit your 29/45 prioritization, if you will, because of those resources are being deployed within the IOUs and other priorities for a larger development. And so these are some of the nuances that happen despite, so to speak, the prioritization of Rule 29/45, which we appreciate given the various Senate bills that enabled this to take place, to actually come into practice.

And again, we do appreciate that the structure of Rule 29/45 does accelerate investment and gives us more confidence. From an actual deployment perspective, our design duration right now in California working with the IOUs is around 148 days, and our construction timeline is 133 days. And so around total project timeline from a utility relationship standpoint is around 285 to 300 days per project, which is still quite a bit far away from the 125-business-day goal that were set up within the energization timelines. And again, going back to the first presentation in this panel from Matt, right, a lot of those are customer responsibilities within those timelines, but there's a lot of nuance on where actually things are held up when these practices are put into effect.

One other point on Rule 29 that I'd like to make is, again, in the implementation, from an implementation perspective, there can be a lot of back-and-forth discussion on implementation with respect to minor ancillary load that wasn't fully thought through from a rule perspective that still needs the spirit of what those rules are meant for. An example is if you want to put a 100-watt security camera at the site, we've heard that we need to do a separate Rule 15 and Rule 16 line extension for a security camera before we escalate because we don't -- want, you know, there's a high rate of cable theft in a given area.

And so we've been working cross-collaboratively from a policy standpoint with many of the IOUs to clarify some of these languages so that from a procedural perspective when we're trying to build as fast as we can within the state those type of nuances don't hold us -- hold anyone up, really, and there's a shared kind of, you know, understanding of, okay, this is in good faith working within these rules. And certainly there's going to be some minor load that is related to charging infrastructure in order to make these projects viable.

And finally kind of ending on the energy storage and Rule 21 front that I already alluded to, Rule 21, you know, is really treated as a separate process from our experience combined to that kind of parallel or combined nature, especially for a new build, when that's so critical to enable energization, especially in a world with capacity constraints that are becoming more and more common. And so we appreciate kind of a lot of the other, you know, procedural rulings that are kind of coming there with respect to flexible interconnection in -- you all know that in 31/41 and all those different processes that exist. But, you know, there's a lot of technology that's deployed today where there's opportunity for more synergies and more uniformity in implementation rules.

And that's actually my next slide here, if we can please move on.

And I think, you know, kind of building on what I was just talking about with respect to various rules, what this slide really shows is how the same exact language can be very -- implemented very differently across the individual IOUs. And what's interesting about the slide, which before I kind of get into it is that each one of these examples represents a practice that's deployed uniformly by that IOU that is not deployed at all by the other two. And so all three IOUs are represented here, which is the interesting part. And so one of the IOUs always asks -- you know, always considers energy storage as an added load, even if you're certifying for example that the producer storage system will not cause the host load to exceed its normal peak demand even if the controls are there, because it's meant to reduce peak demand to solve a capacity issue. We still have to go through a separate load study process in addition to a Rule 21. That is not the case within the other two IOUs.

Similarly kind of the second example here, there's a single IOU that will go through the fast track process for behind-the-meter energy storage and say that because there's too much solar on the circuit, even though this is a non-export energy storage interconnection request, it fails the fast track process and requires supplemental review, which can take two to three months by the time the payment and additional reviews are done.

Now technically, according to the Rule 21 language, yes, the fast track process can be failed because there's too much solar on the system for an energy storage non-export project. The other two IOUs say this is the only screen that fails, that solar is not relevant from a safety or system perspective so we're going to pass the fast-track process. And so what's very interesting is that it can takes us consistently three months longer with additional fees to get energy storage in one of the IOUs through versus the other two.

And finally last example here is a totalized metering. And so from a developer standpoint, of course utility rates are critical, and economics are critical for us to continue to invest in accelerator investments from an ROI perspective, and this is an example where quite a few of the IOUs have discretionary language in their tariffs with respect to allowing totalized metering at their discretion. And what totalized metering means is there's multiple secondary services. You can combine the meters from a demand charge perspective.

And what was interesting in a recent case that happened to Electrify America, we had an understanding with the utilities' representatives that we could totalize a site after energization, and we were told afterwards that the utility exercised their discretion to not allow it, which meant a one million-dollar-plus operational cost hit to us that would have potentially made a site economically unviable from an investment perspective to begin with, and we reoriented our investments in that utility accordingly moving forward.

And so these are all examples where even the same exact language can result in very different actual practices that have real business ROI implications and timeline implications when companies like Electrify America try to expedite interconnection and line extension processes as much as possible working collaboratively with IOUs. And, you know, there's substantially certainly a lot of room for improvement, but we are also thankful for a lot of the policies that are in place. For example, California is the fastest state to get energy storage interconnection by far because of Rule 21. So I want to make sure that I keep that in -- you know, when we’re talking about this in this light, you know, there’s a lot of progress that’s been made, and there’s a lot of progress that can be made of course.

And with that I think next slide.

And that’s all I have. Thank you.

MS. NAKAGAWA: Great. Thank you so much, Jigar.

We’re now going to go to our last panelist. Josh Simmons is president and principal consultant of Prosper Sustainably.

Over to you, Josh.

I’m sorry. I’m not getting your audio on my side. Is anyone else hearing Josh’s audio?

MR. SIMMONS: Oh, sorry.

MS. NAKAGAWA: There we go.

MR. SIMMONS: I wasn’t unmuted on my phone.

So yes. Thank you to the Commission for having me here today to speak to some of the challenges and opportunities with respect to tribes and with respect to energization interconnection and other distribution-related topics.

So my name is Josh Simmons. I am the president and founder, also an attorney with Prosper Sustainably. I've been working with tribes for over 25 years now.

One of my roles is as owner -- lead owners' representative on behalf of many tribes on clean energy projects, whether that's solar storage, microgrids, long-duration energy storage projects, PV charging infrastructure, and a number of other projects. So that's kind of one area that I'm sharing perspective from.

I think the other one is my role as co-director of the Southern California Tribal Chairman's Association Tribal Clean Energy and Climate Collaborative.

Go to the next slide, please.

So the Tribal Energy and Climate Collaborative has been in existence for about two years now under the Southern California Tribal Chairman's Association and its 25 member tribes. We have three program areas. One program is focused on capacity building and technical assistance where the collaborative or TECC is seeking to advance the clean energy climate goals of tribes and fulfilling their priorities including economic and workforce development. There is a program focused on economic and workforce development specifically, where we're supporting tribes and conducting due diligence and developing businesses and accelerating tribally led clean energy technologies, climate technologies, and ventures. And then finally the policy regulatory advocacy programming that mostly right now is focusing on engaging in California Public Utilities Commission regulatory proceedings, but also with CEC proceedings and others as well. And ultimately the overall goal of tech is to identify and advance the climate energy and economic workforce development goals of all of the 25 member tribes.

Next slide, please.

So SCTCA's tribes are spread throughout Southern California in four counties in San Bernardino, Riverside, Imperial, and San Diego counties.

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And I really want to appreciate the opportunity to be here, and really just talk about some of the challenges in particular that tribes are facing in this area. So, you know, first and foremost there are probably at least a half dozen of the just the 25 member tribes that have unenergized homes, like, homes that have been sitting there for a significant period of time without power, in some cases homes that have been without energy for years. We've had tribes that have gotten homes brought to the site, you know, through fed funding other resources, and those homes have sat there for so long without power they've had to ship them out, store them at -- you know, at pretty significant cost to avoid infestation from rodents and other pests. So, you know, tribes are experiencing significant challenges in just getting homes in their communities powered.

So unique to tribes that many other communities don't face, there's some other requirements. So tribes lands are held in federal trust administered by the Bureau of Indian Affairs. And so for certain projects -- a lot of projects, actually, requiring new service and service upgrades -- tribes need to get BIA approval for easements. That process in of itself is time -- takes time and is challenging, but it seems to -- it's kind of known what that process and that timing takes and it ends up taking the utilities a lot longer. So things end up lagging for a significant amount of time in the utility court, and there ends up being a lot of finger pointing that is going on, which is leading to tribes -- tribal members' homes sitting there de-energized without power, with in some cases people paying, making home payments for the home they had supposed to be on the reservation.

The cost of new service seems to continue to increase, making that a barrier too, and some of these homes sit there without power. They find that initially it was one cost, and that cost is even that much higher when maybe they're finally in a position where they've gone through all of the approvals.

Some tribal communities lack three-phase power so, you know, in addition to them tribes wanting to energize and expand their community and at homes, they also are seeking to expand tribal enterprises. Many tribes are dependent -- pretty much all tribes are dependent upon economic development activities and enterprises to be able to fund the revenues for their community and their government. They don't have a tax base that they're collecting revenues from their community members, so without these enterprises they don't have the revenue streams to support their governments.

Tribes and other communities -- other rural communities are facing excessive public safety power shutoff events that seem to shift the cost of prospective risks and impacts to utility and utility infrastructure to tribes and other communities, meaning they're without power for days and longer. You know, it's at the level where we have, you know, food spoiling in refrigerators and entire governments and communities being shut down and not able to operate and to generate the type of revenue streams that keep their governments functioning.

Eligibility for funding for a lot of programs that support the clean energy projects that tribes and others want to see advanced are based on grid connections.

So those tribes are -- there are some homes that are not close enough to even have a grid connection, or if they're not grid-connected they can't for example use the Residential Solar plus Storage Equity Program right now for the homes and then there's a number of those programs too that are only available for to IOU customers.

Related to this, DER incentives of program timelines and requirements can be -- don't really match the reality of projects for tribes and others. So there's a number of tribal solar storage projects that were proceeded under the earlier STF residential -- or, sorry, equity resilience programs during the non-residential side of things, and then there were certain timelines and a lot's happened in the world since then that have led to impacts that have extended those timelines, but the actual program timelines have not been extended.

And then another I think related challenge is that even with the new Residential Solar and Storage Equity program the information that was available on it was not really -- there wasn't enough outreach out there to help tribal communities understand the program and how to take advantage of it, and at this point in almost all territories the funding's exhausted. So, you know, the specific timeline requirements are not matching or not working for tribal communities.

The micro-incentive program that seeks to bring grid resilience capacity to tribal communities to alleviate some of these outages are from in-front-of-the-meter systems only that aren't a good fit for many tribes. They're intended to be tribally owned in-front-of-the-meter systems, meaning their only potential revenue streams are from exporting resources and capacity versus behind-the-meter systems that can actually provide retail cost savings and direct resilience that are completely within the tribes' control.

The incentives and investments and rates that are out there don't seem to align with these behind-the-meter Distributed Energy Resource investments that tribes need that are going to provide them the resiliency the cost savings and the sovereignty control over their own energy resources. So, you know, be that the switch from NEM 2.0 to NEM 3.0 funding going toward undergrounding, which actually now there's apparently less available -- the ratepayers do not now -- ratepayer funding does not fund undergrounding anymore. So it seems to be more incentivizing grid infrastructure investments now, or decreasing the ability of tribes and other -- tribes and communities to invest in resources that ultimately are going to give them the savings and resources they need.

So a lot of the processes for energization interconnection are, you know, somewhat black box processes. Sometimes, you know, we see them out there at a high level. I saw an earlier presentation that kind of went through some of the steps. As owners represented on this project, there are usually a number -- usually a half dozen sub-steps and dependencies within each of those steps. And, you know, it really for tribes that don't have the resources and don't have those working on their behalf to, you know, press upon the utilities have difficulty navigating these processes and progressing. They don't -- there's no set timelines and they don't really know what this next step is and whose court what the next step is in.

Tribes have limited support for them in advancing these things within the utilities, within agencies, where they really need more, and they need that to be support on their side helping represent their interests. There's inconsistent among tribes, so those that do have more resources available to them can be the squeaky wheel and press really hard to push these things -- these types of delays and these types of barriers forward, and then there's the tribes that don't have those resources, that have homes sitting there unelectrified for years and don't really have any clear line of sight of when whatever challenges they're facing can be resolved.

We have encroachment of California regulations upon tribal jurisdiction and sovereignty. One example is CPUC’s rule or Public Utilities Code 769.2 that imposes prevailing wages for projects that are greater than 10 kilowatts, and requiring prevailing wages for those projects. And they end up paying up the developers that are -- and contractors that are doing these projects for others off tribal lands, and that actually holds up projects on tribal lands even though state does not have the jurisdiction or authority to impose prevailing wages or make that call where it’s the tribe’s decision whether or not they decide to proceed with prevailing wages and other types of requirements for projects within their jurisdiction.

And ultimately tribes, you know, are lacking voice and lacking leverage in these situations. You know, through the collaborative we are working to engage in CPUC proceedings and on a more systematic basis but, you know, there’s a lot out there, and we’re finding challenges in navigating this, and even when we identify specific issues and solutions and we are trying to go through the proper channels, we’re finding we’re making, you know, little to no progress, and that -- and then having to be creative in how and how we can have tribal voices heard and kind of exert some sort of leverage in addressing some of these challenges.

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So, sorry, I'm a little bit over time, so I will try to blast through these solutions. So ultimately we're hoping to see a more fully revealed and, you know, increasing the streamlining of the energization interconnection processes, down to -- you know, I think the next step down or even two steps down in the level of, as I mentioned, there can be, you know, a half dozen below each of the ones that were listed in a prior presentation. But there also needs to be -- more importantly, there needs to be tracking reporting accountability for energization interconnection timelines that's visible to tribes and visible to others. So you know, they can't, you know, just be told one thing and another tribe be told something and, you know, they can, you know, point to that when they go to the CPUC and others.

Tribes with respect to easements could use support in proceeding with bridge easements that allow tribes -- that only require tribal approval. So tribes actually can issue easements for less than seven years, but we're finding with one facility in particular, they're not willing to accept that as a bridge for pending DEI-approved easements.

We need better, more accessible distribution capacity information data. I heard that talked about earlier about, you know, PG&E territory, there's an increase in the usage of that data, but we don't know any, you know, better access to that, making sure the data actually is up to date, but training on how to use it, training specific to tribes and, you know, recurring training so that they can understand and access it easily. We want to see more and better TSPS data for tribes themselves on what the TSPS impacts are in their community, but also a greater understanding of utilities and CPUC and CEC on the limits and hopefully limiting the cost-shifting and impacts to tribes in rural communities.

We want to see, you know, greater incentivizing and promotion of behind-the-meter clean energy, Distributed Energy Resources and investments. Again, you know, going back to the days of the California solar initiative, where, you know, less of a specification of less -- of decreasing the benefits of solar, because ultimately if we see more greater investments in grid infrastructure and less investments in community infrastructure, that should lead to lower need for local or grid investments. But costs are going to continue to rise, and it's not going to be the incentive programs for distributed energy resources that are ultimately causing those costs to rise, it's the investments in grid infrastructure.

You know, funding and resources need to be provided for off-grid homes and facilities. There should be more dedicated staff at agencies, IOUs, and one of our team members suggested even utility and regulatory fellowships for tribal members.

We would like to see third-party technical assistance be made available to tribes to evaluate potential projects and distribution capacity, as well as the same third-party TA to support tribes and disadvantaged communities in navigating these energization, interconnection, and other processes, and helping them get through them to successful projects.

We're hoping to see more encouraging of support of tribal collaboration on matters of shared interest, like what the Tribal Energy and Climate Collaborative is doing right now. That would include consistent and meaningful resources for tribes to participate and advocate with IOUs, agencies, and others. So we actually appreciate the CPUC's equity and access program that's funding some of our initial policy and regulatory advocacy programming right now, but the funding that is available for it has a sunset period and, you know, we know we're doing what we can to ensure that there's continuity with this program.

And then ultimately seeing more support for tribal energy sovereignty and tribal and intertribal utility authority formation to help tribes gain greater control over their resources, and I will do one last plug that even though it's kind of outside the realm of distribution for the tribes we're working with, you know, on the transmission side, we want to better work with CAISO and working with tribes as -- with their utility authorities and as well as serving entities, and when they're seeking to be load-serving entities, that they're not treated as generators, and ultimately there's better processes in place for working with tribes.

And that's all I have for today, so thank you so much for considering our feedback.

MS. NAKAGAWA: And thank you, Josh, and thank you to all of our panelists.

We're going to go over to Commissioner McAllister for questions from the dais.

COMMISSIONER MCALLISTER: Great. Well, thanks to the five of you. Sorry, thanks, Sandra, as well.

I know we're quite a bit over time, but I think that's really a function of how interesting the topic is and how much content there is, and so I really want to appreciate everybody for their patience and sort of sticking with us a little bit after the planned time.

I'll try to be quick with questions, just have a couple, and we also want to get to public comment as well. So I really love the growing emphasis on dialing in the distribution grid and optimizing the distribution grid before -- well, sort of alongside all the other things we've been talking about this afternoon. But certainly I think over the last few decades that's kind of been an underappreciated element of the optimization and sort of affordability and incorporation of renewables and, you know, load-based resources and sort of distributed generation -- distributed resources generally. So really happy to see the focus on the distribution grid and also, you know, not only on the sort of planning side, but on the technology side, and I think several of you brought up some solutions that really do help take advantage of the grid we have, right?

In particular, Philip, I really enjoyed all of your solutions and your glass-half-full approach to taking advantage of this incredible investment that we've already made. So not to minimize challenges -- there's tons of challenges -- but the other day we had -- well, a couple of months ago we had a LoadFlex workshop that I think was hugely successful, and really we're starting to deepen that conversation much more broadly, and I think it's been kind of a specialty conversation up to now. How we can actually take advantage of the digital age to manage loads in a way that does fill valleys and clip peaks and really manage the grid for optimal sort of cap-ex and affordability generally.

So anyway, really excited about that, and I think all of your presentations were sort of in line with that general kind of realization and approach.

I guess maybe I'll just ask a question. I think all five of you will have some views on this, but what -- so kicking off, Philip, your presentation, I think, more, but really all of you. You know, appreciate all of what you're doing in your seats to really unlock solutions.

And I guess I'm wondering, you know, what are your views of the best solutions that are available for deployment today, sort of in a pragmatic way, right? So I do a lot of talking about, okay, we need all of our loads to respond, you know, prices to devices, and we need programs, you know, that sort of leverage technology, but those technologies aren't pervasive yet. And so I guess even though they're not rocket science, they exist, but they need to be, you know, maybe there are cost barriers, lots of barriers, but sort of they need to get scale.

And so what are your sort of views of the best technologies implementable today, right? But what beyond that are you most excited about in terms of, you know, on the load side, particularly that's kind of my, you know, area, but also, you know, sort of managing the dance between supply and demand and sort of that optimization at the distribution level. What are some of the things that get you excited as well?

So maybe start with Philip and go on to the others.

MR. KOBERNICK: Thank you, Commissioner McAllister.

I'll give you two quick examples here, but generally the theme is I like things that are simple. Simple, but work great. And, you know, for where we are with decarbonization, we have a long road ahead of us, and frankly I think we all agree that we were hoping to be further down the road than we are now. So things that are simple and can be done quickly and effectively are what I'm really inclined to be pushing here.

So my first answer to your question is level one charging for EVs. It's about how a third of EV drivers for residential drive now. Let's forget fleet for a second, there's tens of millions of cars in California that are owned by individuals that need to electrify in the next decade or so, and for a lot of people that live in multi-family housing are essentially starting from zero, right? There's very little places to charge. And so we really like level one charging as a ubiquitous solution that is extremely affordable -- about $2,000, $2,500 each to install, and now the state, you know, through the

Communities in Charge program is taking that idea and running with it. So hoping to see great results. This is actually the first time level one has been in that program, so we're hoping -- and it's focused exclusively on multi-family. So I think there's a lot of great potential there, and that's an area that we just need to keep pushing and pushing to get lots of progress on very quickly.

My second part of your answer is I'm really excited about lower-power heat pump HVAC systems. HVAC, for single-family home folks, that is the biggest part of the pie when you're electrifying your home. If anyone here has done it themselves, it's generally the hardest part of that equation. So things that can reduce that cost from $20,000 plus project to something smaller I think will make a long difference in terms of reducing those costs and getting ubiquity. Things like the gradient or other similar units I talked about could be part of that solution, but there's a lot of I think interesting innovation to come on that.

COMMISSIONER MCALLISTER: Great. Thanks a lot. Appreciate that.

Anybody else?

MR. SIMMONS: I'll be happy to jump in here.

From an Electrify America perspective, I think from a technology perspective, there's a lot of hardware out there that can solve a lot of the constraint issues, utility capacity constraint issues, but there's a lot of trust issues around that. And so to the extent where the state can identify collaboratively values, say, hey, if you install this relay from one of these three manufacturers and the utility will confirm XYZ settings, you just skipped six months of processes. You're good to go.

And I think UL 3141 is kind of headed in that direction, but that's a general UL standard. I think that it’s, you know, identifying these are the things we're comfortable with. Here's what protects the system. There's no more need for studies and all this other stuff. Let's speed up timelines. I think that's from a technology standpoint.

In terms of what I'm most excited about, one thing I didn't mention in my presentation is that all of our behind-the-meter energy storage within the state actually participates on a daily basis as a virtual power plant, participating in the CAISO system there on a demand response basis. And, you know, we didn't really hear much about V2G and that kind of buzzword frame here today but, you know, I always think of energy storage to grid as the first step before we hit V2G. And we have tons of energy storage assets that if there's more, again, maybe trust around relays or reforming interconnection processes, those could be enabled today to really support the grid in a more cohesive manner. It's really a matter of policy and the wholesale distribution access tariff and all the complexities around that, that those assets can't be used today.

COMMISSIONER MCALLISTER: Thanks a lot.

I'm interested in, Bill, your view. PG&E, I know you subsidized, you provided some subsidies or rebates -- not subsidies, rebates -- for a certain subset of the EV charger market for homeowners, say, for the residential market. And, you know, kudos on the test where you mobilized a bunch of batteries last week. That was great.

Anything to add sort of about what you're most excited about and sort of near-term prospects?

MR. PETER: Yeah. Yeah.

So kind of building on what we were just talking about, thinking that the near term, it is that visibility and the ability to, like, rely and kind of working through how can -- when we're talking about, you know, improving and reducing infrastructure investments, a big key for the utilities is to really be able to see what the customer behavior actually is. So that's the near term for us, is that visibility. That's going to go a long ways.

And then the other thing is the technology is obviously super important, but what we found is that often it's about just working with the customer. Like there are often engineering solutions when there are issues with projects. A lot of the ways we're seeing like easements, all these other things that aren't necessarily about technology. It's about upfront, getting the data, getting that information, getting that communication, and really searching for an engineering solution for the customer.

But looking forward, I would agree that, like, the thing I'm most excited about is kind of that customer-oriented flexibility. So, you know, having that flexibility at the customer site where they're thinking about their own service panel upgrades and things, how to reduce that. I think that'll flow upwards and we'll actually see that then also improving on the bulk scale. But getting down to that individual granular level, we're actually seeing that kind of flexibility that's really customer-driven flexibility and leveraging that for the bulk system.

COMMISSIONER MCALLISTER: Great. That's super helpful. And I don't recall -- I might have missed it -- but mentioning like smart panels, say, and sort of doing more with less. I know there's a lot of interest in that with utilities and much more broadly with the Commission as well. So partnerships there seem like they can do a lot.

Interested in -- so Josh, I really appreciated your perspective, your tribal perspective, and that experience just really came across sort of -- lots of barriers at all sorts of different levels with their -- I guess, are there any tribes where things really are working well and feel like they could be held up as an example of how sort of a process and sort of technology application works in a way that we can learn from and key off of?

MR. SIMMONS: Yeah. I mean, I think tribes are leading the way with a lot of clean energy systems. I mean, we have Viejas, which is one of the largest --

COMMISSIONER MCALLISTER: Yeah. Exactly.

MR. NEDRUD: -- bar none.

Rincon, we have another CEC deployment, some long-duration energy storage. It's just, like, you know, it works well. Some of these programs that are enabling those types of successes work well for some tribes that are located in a certain area, have a certain type of operation, have certain resources. And ultimately, like, we are having success in breaking down some barriers and stuff like that. But how do we create that type of success across the board?

You know, when you asked the earlier question, I was thinking, well, you know, it's challenging for tribes in going to decarbonization because, like, you know, it's hard for them to go away from going from propane or gas or even wood, like, you know, electrifying their homes when they can't even get power or they're limited to single-phase, unreliable power. Like, you know, going to an EV -- going to an electric vehicle is just really not an option for them.

o, how do we, I guess, you know, tribes if -- I found that tribes can move quickly and have success using, you know, previously like DAC-SASH. I mean, you know, the multifamily ones don't work for most tribes. So, there just aren't multi -- you know, the new rounds of community in charge were multifamily. So, you know, how do we help tribes in deploying some -- I think, more solar and storage capacity for homes and facilities that can be paired with -- you know, if you're going to say, okay, well, install community charging infrastructure, do some decarbonization, electrification type of efforts. Well, okay. Well, how do you put the resources right there that don't require the grid upgrades that are just huge barriers, way too costly for them to actually proceed with?

COMMISSIONER MCALLISTER: Okay. That all makes a lot of sense.

And my question -- I didn't frame it sort of tightly enough, but I was really thinking about sort of that customer-utility relationship. And you started to get to that just now with respect to like, okay, what programs really are actionable for tribes that also have benefits to the grid? And I think that sort of behind-the-meter reliability support in remote places to improve, you know, service quality, but also potentially defer costs. It seems like an area where at least a number of tribes could probably work really productively with their respective utility to sort of figure out where those wins-wins are. But that would take, that would take, you know, a concerted effort, which I would absolutely encourage.

MR. SIMMONS: Yeah. I just -- sorry, just to touch upon that too. Like, I mean, I think that's what the collaborative that was recently formed is kind of trying to do. It's like, how do we create greater visibility and access to those programs?

It's just like -- there’s a trust factor there. And then there's also -- at one point there was a fire hose of all this funding and resources coming out. And just like, you know, you have somebody from your tribe that has so many different hats, but I think if you can -- if programs can be queued up in a way that do meet tribal needs, brought from a trusted voice that are analyzed in a way and, you know, curated in a way that actually works for the community members, you can get a lot of uptake and a lot of success. And then if one tribe sees success from another tribe, that ends up leading to more tribes taking advantage of programs across the state.

So with that, some of the -- you know, some earlier engagement in ways that kind of work for tribes -- work for tribes’ trusted partners too, because just, like, ultimately they are relying upon others to better understand and access some of these programs.

COMMISSIONER MCALLISTER: Great. Thanks a lot. That's really a great vision. And I'm glad that collaborative is starting to push in that direction.

So then wrapping up, Matt, you know, all this -- you know, everything that touches the distribution grid, right, is both a potential opportunity and a potential problem for you.

I wonder, you know, if you could sort of comment on, you know, all of this beehive of activity, you know, all over the distribution grid. Is there anything that makes you sort of either nervous or optimistic or both probably?

MR. COLDWELL: Yeah. I think so, Commissioner.

COMMISSIONER MCALLISTER: Sort of complexity, right? I mean, that's kind of the name of the game.

MR. COLDWELL: Yeah. Yeah.

And my apologies. My computer slows down just like me as the day moves on. So if my video is freezing a little bit, I apologize.

Yeah. I mean, as I highlighted earlier, I mean, we have so many different -- and, you know, actually, some of my fellow panelists sort of alluded to this too, is that, you know, we have so many different regulatory proceedings that are covering all of these various topics.

And to the extent that we can start dealing really with them a little bit more holistically, I think it does make a lot of sense. I think Jared kind of keyed on the, you know, some projects requiring Rule 21 and the energization process and, you know, that introduces a lot of complexity and time to a project. And I fully, you know, appreciate that -- you know, that historically, these things have been done separately, and now we're entering a world where, you know, we should be thinking about these things a little bit more holistically as we get projects that require that insight. So I think that's a challenge, but I also find it -- you know, some optimism in the fact that, you know, we are currently, like, identifying a lot of these challenges, and I think we can start to take up a lot of these issues in some of the proceedings.

I'd mentioned the new interconnection OIR that, you know, hopefully is voted out on Thursday. And so, you know, there's an opportunity there to raise these types of issues, as well as, you know, within our energization proceeding, we'll eventually have a phase two to that proceeding. And so, you know, these are very much issues that could be in play in, you know, one or both of those.

And, you know, the benefit is we just, we have -- you know, all of this is done under my purview of my responsibilities. And so our teams work together really closely and collaboratively. And I think that's a big, big first step towards ensuring that we're thinking about these things together is, you know, having the teams that are actually working on it talking to each other, you know, and breaking down those silos.

So I think just, you know, maybe to more directly answer your question that you teed up is, you know, all these things being part of distribution planning and being on the distribution system that, you know, how do we break away from the way things have previously been done in silos, and move forward in more of a way that's, you know, really looking at the system, you know, and how it operates, how it's planned for, and incorporates all of, you know, these new devices and new types of customer loads. So I'm not sure if that was more of a challenge or optimism, but that's --

COMMISSIONER MCALLISTER: Well, I mean.

MR. COLDWELL: -- I mean, those are some things we're thinking about.

COMMISSIONER MCALLISTER: I really appreciate it. And I mean, we heard early in the afternoon when the first panel -- you know, heard the sort of bulk grid and interconnection status from the agency perspective, but then, you know, from a bunch of different folks, the second panel about the bulk grid, and, you know, now we're talking about the distribution level. And so there's, you know, that challenge to not just laterally communicate with all the stakeholders in any given level, but also up and down the chain. So the customer doesn't get crazily confused with, you know, what's going on as a result of maybe, you know, a FERC tariff or something. So I think that, you know, then relating that down to the retail level.

So I think we have a lot of things going on at once, and I think today has been a really beautiful kind of status report on all of it. So I really appreciate you five and all the previous presenters today for your expertise and thoughtfulness and being with us and sticking it out a little bit over time, so -- and that did not help just now. So thanks a lot. All right. Appreciate it.

So I think I'll wrap it up there. I don't know if we have any public Q&A, but I'd like to pass it off to Brian McCullough to manage that if we do. Thanks, everyone.

MR. MCCULLOUGH: Hi. I'm Brian McCullough.

And we did have one quick question from the audience. There was a question, could PG&E tell how a customer could find the status of a transformer upgrade they committed to 16 months ago for a school solar project?

MR. PETER: Sure. I can -- yeah.

So just generally, you know, with regards to sources of information, there's obviously the GRIP portal we mentioned before. There's a Rule 21 interconnection reporting, and then also the energization timelines reporting that my colleague mentioned earlier. So there is, but I think really when we're talking about like individual requests like this, that obviously there's, you know, talking to if you have a service representative or something like that.

I don't know this particular solar project, so I'll take this back and we'll follow up with Claire on this particular project to provide information, but just for the broad answers, those are like the general approaches to find out the information on either your energization or interconnection requests.

MR. MCCULLOUGH: Thank you.

MS. NAKAGAWA: Thank you, Brian.

We're now going to move over to the public comment period. As a reminder, one person per organization may comment and comments are limited to three minutes per speaker. While we welcome your comments, we will not be able to respond to them during the public comment period. The workshop notice does provide information about how you can contact us with any follow up questions you might have on the workshop content.

So we'll be using the raise hand feature today on Zoom. Please use that now if you'd like to make a comment. We will then call on you and open your mic to allow you -- to open your line, rather -- to allow you to make comments at the beginning of the comment. Please state and spell your name for the record and state your affiliation if you're speaking behalf of an organization.

For those on the phone, we will have you dial star nine to raise your hand and then star six to mute or unmute.

We're first going to go to the Zoom raised hands. I'm going to give it a minute, see if anyone wants to make public comment on Zoom. Please raise your hand now.

All right. Not seeing any.

We are going to go over to the phone lines. You can do star nine to raise your hand if you are calling in via phone and want to make public comments. And those on Zoom, you can also still use the raise hand function.

Okay. Well, with that, we're going to turn it back to Vice Chair -- sorry, Commissioner McAllister.

If you do want to make written comments in the docket, you have until 5 p.m. on August 25th. You can submit written comments to the docket.

Commissioner McAllister, over to you for closing remarks.

COMMISSIONER MCALLISTER: Thank you so much, Sandra.

I just want to thank you and the whole IEPR team for helping -- well, it's really for wrangling this really rich discussion today and everything you do in all aspects of IEPR. A lot of challenging topics we're working through, lots of stakeholders, lots of -- I mean, we're so blessed to have so many smart, engaged folks doing vital work in the state. And today was a huge example of that.

So I really appreciate you and the whole team and all the speakers and folks who stuck it out after close of business today. I really appreciate it. I was riveted and I'm sure a lot of you were as well.

So we absolutely encourage comments, written comments. I think the written comments sort of give stakeholders the opportunity to deepen their comments and sort of provide data and sort of structure input in a way that sometimes isn't available or isn't sort of doable in real-time live at a workshop like this, so we really appreciate your providing that rich background in the written comments on the docket.

I'll just speak for both the Vice Chair and myself that today's been great, and thanks again to the moderators. I want to -- thanks to Sean and the whole IEPR team and Molly for being here with the -- I'm sorry, Sean and the whole staff side of it. Subject matter experts, Molly from CPUC and Neil Millar, all three of you are always so great to listen to. And all the presenters from CAISO and the utilities and advocates really appreciate all of you as well.

Much more to come through this IEPR cycle, and this will be really important to feed into the various aspects of the work we do together across the agencies, our forecasting work and SB 100 planning and just all the various project work that's going on across the state.

The slide that Molly presented at the beginning of her talk just looking at the huge wedges of resources, you know, storage and solar and all the rest of it, we're seeing different storage technologies, we're seeing different geographies. You know, we're really seeing challenges emerge with this massive build-out, but also the results that the build-out is giving us as a state, and I think that will be clear even across the West, actually, as California's infrastructure build-out helps budget reliability across the West as we go forward in the coming, you know, months and years. So that was -- that's an incredible narrative, really.

And not to minimize the challenges that we talked about this afternoon, but I think it is worth highlighting the fact that we are really leaning in. We're walking the walk and we're putting in place -- we, the royal we, across the state, finance community, technology, cities and counties across the country, you know, a lot of people doing a lot of heavy lifting to get this build-out accomplished. So I'm really optimistic for the future, and especially just hearing all the collaboration that's going on during the course of the afternoon.

So with that, I'll stop and just say thanks again to Sandra and the team for opening this conversation and providing the platform to have it.

And back to you, Sandra.

MS. NAKAGAWA: Great. Thank you, everyone.

We are adjourned for today.

(The workshop adjourned at 5:19 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 17th day of September, 2025.

Martha L. Nelson

MARTHA L. NELSON, CERT**367

CERTIFICATE OF TRANSCRIBER

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

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

I certify that the foregoing is a correct transcript, to the best of my ability, from the electronic sound recording of the proceedings in the above-entitled matter.

Martha L. Nelson

MARTHA L. NELSON, CERT**367

September 17, 2025