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CALIFORNIA ENERGY COMMISSION

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LEAD COMMISSIONER WORKSHOP

INCREMENTAL EFFICIENCY IMPROVEMENTS TO THE NATURAL GAS POWERPLANT FLEET FOR ELECTRIC SYSTEM RELIABILITY AND RESILIENCY

REMOTE VIA ZOOM

WEDNESDAY, DECEMBER 2, 2020

9:00 A.M.

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P R O C E E D I N G S

9:01 A.M.

WEDNESDAY, DECEMBER 2, 2020

MR. BARTRIDGE: Good morning everyone and thank you for joining us this morning. I'm Jim Bartridge with the Energy Commission's Siting, Transmission, and Environmental Protection Division. Thank you for participating today in our Lead Commissioner Workshop focused on Incremental Improvements to the Natural Gas Power Plant Fleet for Electric System Reliability and Resiliency.

Before we get started I'll turn to our Public Advisor, Noemi Gallardo, for some background and housekeeping logistical items.

Noemi, let me turn it over to you.

MS. GALLARDO: Hello everybody. Good morning. I am Noemi Gallardo, the Public Advisor at the Energy Commission.

Today's workshop is being recorded and being held remotely without a physical location consistent with Executive Orders N-25-20 and N-29-20, and the recommendations from the California Department of Public Health, to encourage physical distancing to slow the spread

of COVID-19.

The public may participate and/or observe the meeting consistent with the direction in these executive orders. Instructions for remote participation can be found in the notice for this workshop. If you have any trouble with the Zoom online platform during the meeting, you can also call in at (669) 219-2599 or (877) 853-5257 and enter the morning session I.D. 927 7901 5365. I know that's a lot of numbers. We also have them posted on the slide there.

Additionally, please note that the master deck of PowerPoint slides being shown today will be posted very shortly to the Energy Commission's website at energy.ca.gov. And on the home page, you would scroll down to events and you can find the link to the workshop and related material there.

So the COVID-19 pandemic continues, unfortunately, and California now has over 1 million confirmed corona cases, and it is expected that numbers will rise through December. So we encourage everyone to stay safe and take the following steps, wash your hands, wear a face mask, clean frequently, and maintain at least six

feet of distance from others, and visit covid19.ca.gov for more information.

Next slide.

Zoom is the Energy Commission's online platform of preference. I'll provide some quick instructions to improve your experience.

For those who can see on this slide, we included images of the various icons you can use during the workshop. We suggest clicking on gallery view in the upper right corner of your screen to see all speakers simultaneously, or if you prefer you could click speaker view to see one speaker at a time.

At the bottom of your screen you'll see a black bar with a raise-hand icon that looks like a high five that you can use during the public comment period. For those who are panelists you can use the icon that looks like a microphone to mute and un-mute when appropriate.

Please note that the chat and Q&A features are disabled for this workshop for attendees.

Next slide.

There are two periods of time dedicated for public comment during today's workshop, one

this morning following the panelists' presentations, and another following the afternoon panelists' presentations. Due to time constraints, today's speakers will not respond to questions asked during the public comment period.

Each person will have up to three minutes to speak. And organizations are limited to one representative. If you would like to make a comment in Zoom, click on the raise-hand icon to let us know you'd like to make a comment, and we'll let you know once we've opened your line to speak.

For those who have phoned in, press star nine to raise your hand and star six to un-mute. We will open your line during the public comment period. When you are called upon, please spell your first and last names, also, state your affiliation, if any, for the record, then begin your comments.

Alternatively, we welcome written comments which are due by 5:00 p.m. on December 16th. The meeting notice provides detailed instructions on how to submit comments. On this slide we included links to where you can visit to file comments electronically and where to click

to view all documents filed in this docket.

With that, I'll turn it back to Jim.

MR. BARTRIDGE: Thanks Noemi.

I'll review the agenda for today's workshop. And then we'll move to opening comments from Commissioner Douglas and others.

This morning, we'll have two panels. The first panel will discuss various incremental technology improvements that could be made to existing natural gas power plants, and the benefits they could provide. The second panel will discuss opportunities, challenges, and process modifications that may be needed to realize these incremental improvements.

This afternoon a third panel will explore how the incremental improvements identified in the morning could potentially be procured.

With that, let me turn it over to Commissioner Douglas and other Commissioners for any opening remarks.

COMMISSIONER DOUGLAS: All right. Well, good morning everybody. Oh, let me see if I can get my video on. All right. Well, here we go. So good morning everybody and thank you for organizing and participating in and taking part

in this workshop this morning to everyone who's joined us.

As Jim Bartridge said, this workshop focuses on looking at the natural gas fleet in California and how we can bring forth incremental improvements to the efficiency and reliability of that fleet.

As I think we all know, California is moving very quickly towards a much more aggressive set of goals for reducing greenhouse gas emissions in our system and transitioning our electricity system increasingly to a zero-carbon emission system. And as that transition occurs, pursuant to our SB 100 goals and other policy goals in the state, we will see the gas fleet and gas plants operate less, and we're already seeing gas plants operating less. However, they play a very critical reliability role and are likely to continue to do so for a significant period of time, as we've seen in a number of analyses, but most recently the work being done with the Energy Commission, the Public Utilities Commission, and the California Independent System Operator, looking at our SB 100 goals.

So the focus of this workshop, as Jim has

noted, is what we can do in terms of incremental energy efficiency or efficiency, process efficiency improvements, or other types of investments at the gas plants that -- or at certain gas plants that could enhance and increase their ability to provide this important reliability function. And of course, we're doing this with an eye towards Summer 2021 but, also, with a potential longer-term perspective, as well, depending on what we hear and what the potential benefits and costs can be.

Certainly, we know that in the events we had this summer, it was -- the gas plants did play an important role in preserving electricity services and producing electricity that we needed. We did see, in some cases, de-rates, in other words, plants producing less than they are capable of, largely due to the heat. And I know that one of the approaches we'll be looking at today just looks at how to improve the productivity or the generation during high heat events.

So in any case, I'm very interested in hearing the discussion, both this morning and this afternoon, and thank everyone again for your

participation.

Thank you.

MR. BARTRIDGE: Would any other Commissioners like to make remarks?

CHAIR HOCHSCHILD: This is David Hochschild. Just good morning and thank you to all the stakeholders and Staff who put it together. I look forward to the discussion.

COMMISSIONER RANDOLPH: This is Commissioner Randolph. I don't have much to add to Commissioner Douglas's excellent introduction. Looking forward to the discussion and seeing how we can get more capacity out of our smaller fleet, so thank you very much. Looking forward to it.

MR. BARTRIDGE: Great. Thank you, Commissioners.

President Batjer, any comments, or should I keep going?

PRESIDENT BATJER: Let me see. There we go. Thank you so much. I agree with my fellow colleagues.

Excellent introduction, Karen. Thank you.

And I look forward to the comments and

participation and a briefing, so thank you very much for conducting this today and for all the work that it took to do so.

Thank you.

MR. BARTRIDGE: Great. Thank you.

Mary, slide seven please.

And thank you, Commissioners.

I'll take a few minutes to set the stage for today's workshop which, as Commissioner Douglas said, focuses on incremental improvements to the natural gas power plant fleet to support electric system reliability and resiliency.

During August and September of 2020, California and the Western U.S. encountered unprecedented extreme heat storms, with temperatures ranging from 10 to 25 degrees above normal. We all know that when it gets hot, energy use goes up, and the energy demand exceeded both supply and our planning targets. At the same time, many active wildfires were also raging across California and the west. And together the heat and wildfires significantly impacted the energy system, affecting both generation and transmission.

As a result, to maintain grid stability,

the CAISO initiated rotating outages for the first time in 20 years. California's natural gas power plant fleet accounts for more than half of the state's total generation capacity and we relied on them heavily in August and September.

However, the high temperatures and dispatch stressed multiple subsystems of the natural gas power plant fleet and resulted in de-rates and curtailments. So as we look ahead and think about reliability issues in the summer of 2021 and beyond, incremental investments at the existing natural gas power plants may help avoid those de-rates and curtailments.

Slide eight please.

At Governor Newsom's direction, the Energy Commission and the CAISO and the Public Utilities Commission submitted the Preliminary Root Cause Analysis Report on October 6th, identifying the cause of the events leading to the outages. Because there's been a lot of discussion on this topic already and we have a lot to cover today, I won't spend a lot of time on this.

As the report indicates, there were three main causes. The existing resource planning

processes are not designed to fully address the extreme heat events. Planning targets have not provided sufficient resources to reliably meet demand in the early evening hours, and these challenges were amplified by the extreme heat. And then, finally, there were scheduling issues at the CAISO day-ahead markets.

Next slide please.

Here are the Root Cause Analysis Report recommendations that the agencies are continuing to work together on. The first is to examine emergency procurements, perform statewide resource assessments, improve communication protocols, and enhance market practices.

Next slide please.

So getting back to the topic of today's workshop, and I won't read these completely, but we feel the natural gas power plant fleet can help us meet near-term system reliability and resiliency issues as we move towards our SB 100 goals. Plant improvements implemented by Summer 2021 and beyond can help mitigate future stresses on our electric system like we saw this summer. And these near-term physical improvements can increase output, efficiency, turndown, and

flexibility, all of which can provide insurance against extreme weather, fire, or climate-related events and help smooth the transition to our SB 100 goals.

And let me just say that, also, the agencies together, recently released the SB 100 Report. There will be a workshop on the Draft Report this Friday, so just a quick public service announcement there.

And with that, I'll turn it over to Kenneth Salyphone to provide a brief overview of California's existing natural gas power plant fleet and some of the potential upgrades we've been discussing.

MR. SALYPHONE: Thank you, Jim.

Good morning everyone. Thank you, Chair, Commissioners, Staff and panelists for your time and attention during today's workshop.

My name is Kenneth Salyphone and I am a Mechanical Engineer with the Energy Commission. I'll be presenting information on California's power plant fleet and the potential efficiency improvements for them.

Next slide please. Thank you.

This chart shows California's in-state

generation resource capacity in megawatts for the past 20 years. The chart shows that the baseload resources, such as geothermal in orange, biomass in green, and hydro in pink, have not significantly changed and remain relatively flat. In contrast, there have been declines to some of the generation resources, such as coal, oil, petroleum coke, which are lumped into other non-renewables shown in blue. Nuclear, shown in black, also declined in capacity. On the other hand, wind and solar have noticeably increased. Solar is shown in yellow and wind in purple. Natural gas, shown in red, which constitutes the largest stake within the in-state generation resources has varied in capacity.

The changes you see on this slide have been the result of increases in cleaner renewable generation in response to the state's plan to reach 100 percent clean energy.

Next slide please.

Next we have the historical trend of in-state generation by resource in gigawatt hours for the past 20 years. Like the generation resource capacity, the baseload resources of geothermal and biomass, shown in orange and green

respectively, have been relatively flat. Other non-renewables shown in blue, nuclear shown in black, and natural gas shown in red have seen declines in generation due the shift for cleaner renewable generation.

With this shift, solar and wind resources are providing more energy to the grid, which are shown in yellow and purple respectively. Shown in red, we see that the generation from natural gas has declined in the last few years and this can be explained in the next slide.

Next slide please. Thank you.

Here we have the in-state natural gas capacity in megawatts, specifically technologies that use natural gas. Shown in green we have cogeneration plants. In red are peaker plants. In brown are the aging plants. In purple are combined cycle plants. And at the bottom in blue are the total capacity that has retired.

The chart shows that the growth in the combined cycle and peaker plants and reduction in capacity of aging fleet, partly because of the increase due to plant aging and retirement, which includes nuclear plants. The overall natural gas capacity and generation have decreased relative

to their peak in 2013. The loss of capacity has put the state in a situation where the supply of energy is challenging the state's electrical demand during extreme weather events.

Next slide please.

As mentioned, California experienced record-breaking heat storms in 2020. Peak energy demands stressed multiple subsystems of natural gas plants. Wildfires and smoke blocked the suns rays to solar panels. And wind was not available for wind turbines. In addition, once-through cooling plants were limited in capacity. In September, rolling blackouts were prevented by load shedding. Consequently, these events have been a learning experience, one that allows for planning and preparedness for the future.

Next slide please.

The natural gas fleet currently plays a key role in meeting California's electricity demands and constitutes roughly 50 percent of California's capacity. It is also reliable and highly dispatchable. Increases in operational flexibility, which includes start times, ramp-up, turndown, efficiency, and capacity are potential improvements for the natural gas fleet to

increase generation during peak times.

Next slide please.

Combined cycle and simple cycle plants have potential for improvements in the areas of advanced gas path, inlet air cooling, and other cooling systems. While cogeneration plants are part of the natural gas fleet portfolio, they are not considered for improvement because they are dependent on their thermal hosts and, therefore, not as dispatchable.

Next slide please.

AGP improvements include replacing mechanical components within the turbine. Advances in metallurgy have allowed upgraded components to withstand higher pressures and temperatures which improve output, efficiency, and operational flexibility.

Next slide please. Thank you.

And the air cooling system cool the air before entering the gas turbine to increase air density and mass flow rate. Many plants use evaporative coolers. However, mechanical chillers would recover more peak output during hot summer days, especially when atmospheric humidity is high. Evaporative coolers are

relatively inexpensive. They operate with low parasitic loads but increase water consumption.

Mechanical chillers are more effective at rejecting heat. And even though they use slightly more parasitic load, they increase overall power output. Chillers use refrigeration gases as cooling medium. While some refrigerants are considered hazardous in California, other non-hazardous refrigerants are available.

Next slide please.

Other cooling systems can be improved to increase efficiency and performance. One example is pre-cooling the inlet air before entering the air-cooled condenser. This increases the heat transfer capacity of the air.

Another example is spraying water mist in the compressor compartment within the turbine unit. This increases the air mass flow rate which results in higher output and efficiency.

Next slide please.

Another improvement can be realized by adding onsite battery energy storage. Stored energy can be a spinning reserve and act as an enhancement during startup. Batteries can also be readily dispatched during peak demand.

Moreover, batteries can be configured to serve the stations' loads, which would reduce parasitic loads during the generation for grid use.

Another area where improvements can be made is the operating system software. Software can be upgraded to allow the turbine unit to operate above its original design or warranty limits to meet demand during extreme heat events.

Next slide please.

Thank you, again, for your time attention. I pass this over to Jim, who will continue with today's program.

MR. BARTRIDGE: Great. Thank you, Kenneth.

Let's move directly to Panel 1 for a more in-depth discussion of these technologies and the benefits they can provide. Here are a list of our panelists today. And first up is Peter Blaes and Joshua Minnix from General Electric.

Go ahead and take it away, Peter.

MR. BLAES: Okay. Hey, thanks, Jim, and the Commission. GE really appreciates the invite to the workshop and just being part of this discussion.

So Kenneth, I appreciate the lead-in, as

well as some of the possibilities out there.

You know, GE, when we look at kind of the fleet in California, we're very proud to say that, you know, a significant portion of gas coordination -- a significant portion of the generation, gas generation, comes from equipment with a GE meatball on it. So as we look at the turbines and the plants, we classify them, you know, further down.

So on the left side of the screen you're going to see we have three main classes of units in the state, B Class, E Class, and F Class. Those are kind of classes of technology. As we've evolved with power plant designs and gas turbine designs, each of those has different technology in them, and each has different capabilities and things that we can do to them; right? And we continue to invest in our gas turbines. We actually have a newer class of technology, the H Class.

And so one of the things that we do as we push the limits of gas turbines and keep pushing them for more output and flexibility, we actually take those new designs or things out of the new turbines and then we kind of start to retrofit

our older designs with those improvements; right?

So as Kenneth mentioned, you know, there's material differences, there's design improvements, there's sealing improvements, our coatings. And nowadays there's lots of manufacturing improvements as well. So we have a lot of things that we do with what we call additive manufacturing, which just makes the turbines all that more capable. And so we can go back and retrofit any of our older units with different technologies as we push forward. And that's what gives us the capability -- right? -- to really stretch the units that are in California. So even when you look at F Class units in California, that is now a 30-year-old technology, and so there's a lot that can be done.

So on the slide you see a few of the capabilities; right? To go through every possible upgrade or every possible thing we can do takes hours and it's a significant list -- right? -- on any class of this technology. But you know, it can be as simple as changing out a few blades in a compressor section of a turbine, or a few rows of blades, to changing out whole

combustion systems, whole gas path systems. The advanced gas path was mentioned earlier; right? So it can range greatly; right? But we can squeeze a little bit more output out of almost any unit but it varies from plant to plant -- right? -- and unit to unit.

One of the things that we do whenever we approach projects like this is we, also, then look for what else -- right? -- not just the output at the top end or the capacity but is there any other needs; right? Is there needs for, actually, more turndown; right? Which means getting to lower loads with the turbine still running at emissions compliance, and so we have a lot to offer there as well. And again, it can vary anywhere from a smaller, less intrusive option into the turbine -- right? -- versus a whole changeout of internal parts and components.

And then we look at start times, ramp rates, fuel flexibility. Hydrogen is a huge topic of discussion these days in the gas turbine world. Our turbines already have some capabilities to burn hydrogen gas as well. And we continue to invest in that capability and pushing the limits with hydrogen as well.

I didn't put it on this slide but GE, we do have battery systems and electrical storage system, and so we are experimenting with projects that kind of combine those systems with turbines, whether that's for a black start capability or for spinning reserve. And I think Josh will hit on the spinning reserve piece a little bit later.

So next slide.

So this is just a quick high-level example. And this is from a similar technology type of plant. A lot of these plants are in what we call two-on-one combined cycle configurations, or it's two 7F turbines and a steam turbine running in combined cycle.

And so you can just kind of see high-level numbers here of what capabilities were when we first built the plants and built the units and what those capabilities can be today. This example is an extensive project; right? This would be a whole new combustor and a whole new gas path in the turbine, as well as some tweaks to the compressor, and from a software perspective -- right? -- and a controls perspective. But with that type of project, you can significantly increase the total operating

envelope or operating range of the power plant. And you can also improve the flexibility of the plant itself.

So something else that we look at -- -- as I mentioned before is ramp rates and how fast we can get that energy to the grid for reliability and resiliency purposes. So we can go two to three times faster than when some of these plants were first built, you know, depending on configuration. So we can do a lot of significant work there, significant improvements.

We can also help with the maintenance intervals in kind of optimizing those so that there's less down time from a maintenance perspective on those.

So overall what I'd say is with any of these projects, they can get very complex. The plants themselves are complex. And every plant is a little different; right? And also, needs are a little different from one generator to another.

So they are complex. We have the capability to design and tweak and a lot of levers to pull in the gas turbine space to

improve the plant's performance but its detailed conversations are from a planning perspective. We want to be out ahead of these type of projects by at least a year, usually. The lead times for the components themselves can range anywhere from, you know, three months to a year. Costs can vary significantly depending on what you're doing and what the goals are. But there's no one-size-fits-all solution, so it really takes some time and some efforts to dig in to what, you know, the generator of the site really needs.

But at GE we're excited about all the technology improvements we can make. And we're excited to try to help the generators in California do whatever is needed to solve the current issues.

With that, I'll turn it over to Josh.

MR. MINNIX: Great. Thanks Peter.

We can advance to the next slide.

Appreciate, again, the Commission giving us the opportunity to participate in the discussion today. My name is Josh Minnix. I'm the Sales Director for North America for our Aeroderivative Services Business. So we support a fleet of over 150 aeroderivative units in

California, providing over 9 gigawatts of power.

In a similar manner, I've laid out in the slide here some of the possibilities that we see for the existing fleet in California. The air technology is driven from aviation technology and it provides highly efficient, flexible, modular, on-demand power when it's most critically needed.

We took some of our categories of upgrades and put them into two buckets here, some focused on the summer of '21, these are more immediate-term solutions, and some that we could implement by summer of 2022. I'll focus on some of the similar performance and capacity upgrades that the technology is entitled to.

Similar to Peter's discussion on the heavy-duty units, our aeroderivative technology is capable of producing increasing peak output by looking at modifying the control software, as well as the material choice and technology within the combustion system itself. We see that opportunity across the range of our technologies that already exist in California. And I've tried to capture some of the fleet-level possibilities, given the large number of units that are in peaking and combined cycle application across the

footprint today.

An additional consideration when we think about reinforcing the available capacity that exists in the fleet today, one of the unique aspects of GE's aeroderivative fleet is the ability to do more modular and quicker outages as the need may arise. We've got programs in place to help our customers which range from utilities to IPPs to cogenerations the universities of California, to having lease assets available, ready to respond within a 48-hour window or spare engines onsite where the incremental availability and reliability can be quickly realized with an engine exchange.

Similar to our notes on our combined cycle heavy-duty fleet, the aeroderivative fleet is particularly flexible and agile. It's a fast-starting technology and we have pushed the envelope on that capability even further, now being able to get our start times down to five minutes, which brings incremental megawatt hours to the grid.

When we think about some of the longer-term solutions, again, we've increased the technology capabilities on each of the platforms

over time, improving both the geometry and materials capability. And some of that can be realized by replacing turbines with upgraded units. We've highlighted some of that in the right-hand side of the slide here as well.

And finally, just to briefly touch on hybridization of aeroderivative assets, I think this is a place where we've really unlocked new potential for the existing fleet in California and elsewhere with our customers by pairing our aeroderivative turbines with battery energy storage systems, unlocking, effectively, 50 megawatts of spinning reserve with only a 10 megawatt battery. It provides a linear response for a minimum load of zero megawatts all the way to the full entitlement of the gas turbine itself.

So to close on the GE side of the presentation here, lots of technology options for a large, critical fleet that exists in California. And happy to partner in these discussions on how to unlock the most potential.

Jim, that will conclude my remarks. Thank you.

MR. BARTRIDGE: Thanks Joshua.

Next up we'll go to Alex Morris with the California Energy Storage Alliance.

MR. MORRIS: Hi Jim. And hi everyone. Thanks. Hopefully, you can hear me okay. I'll speak on behalf of CESA, the California Energy Storage Alliance and, again, it's great to be here. I think this is a very important discussion for focusing near term on the fleet we have and how to leverage it for reliability.

I think one of the key distinctions you'll hear from me today is you saw a lot of different tools in the toolkit for improving the efficiency of these gas units and a lot of that does target these heat storm periods. What I'll speak about today is something that helps in the heat storms but also helps every other day of the year and, to me, really is a low-hanging fruit that the state should be aggressively exploring for adding, in addition, these to our gas fleet. There's a ton of benefits and I'll speak to that. And I'll share some study data as well.

Next slide.

So really quickly, for those who aren't familiar about CESA, CESA is the main energy storage association in California. We're about

100 members. We're the voice of storage here. And we're tech-neutral, so we support all types of storage as long as it's meeting the grid's needs. I think that's very important because that principle makes sure that CESA's voice is really supportive of the grid's needs and less so of particular company perspectives.

That said, we do have, you know, a ton of companies that are invested in California through CESA and are expecting us to be their voice to help there be storage market opportunities for them, so it's a pleasure to work with you all. And those of you that I've built relationships with, thank you.

Next slide.

Yeah, and CESA is tech-neutral and business-model neutral. So whether it's a utility-owned storage system, or a hybrid gas storage system, or a solar-plus storage, we're open to that as long as it's meeting grid's needs. And I think that will -- that's going to play in here, why we think we see a good opportunity for adding storage to these gas units.

Next slide.

So stepping back, really, a question the state needs to wrestle with and continue to wrestle with that's emerging here is we have a plan for SB 100 when it comes to our renewables, we're going to build them out. We have this growing plan through the Integrated Resource Plans and whatnot about adding storage to our fleet. But the pathway for our natural gas fleet has always, to me, been a bit unclear.

There's recognition that we're going to need the gas fleet, that it's crucial for reliability, particularly near term. And the state, I think, hasn't had a full roadmap for when and how it starts to wind down its use for the gas fleet. What the smart strategy? What's the economic approach there, et cetera?

And so what we did at CESA is we sort of looked at that specific question and tried to do some modeling that we'll share about. And one of the things we found is that a lot of the gas remains useful for the system, in part for providing energy but often, also, for providing contingency services, like spinning reserve or being available inside a local area in case there's a contingency. And so when you're using

the gas in that way there's a huge benefit to adding storage to it because then the gas system can, basically, be -- capacity can be online without actually burning emissions, et cetera.

Additionally, when you add storage to it, you start to see faster rampings, you know, two times the speed of ramping if you add it to a CCGT, so you have a much better load-following capability. And a lot of that translates to lower emissions, healthier environments in California, et cetera. And all of it is extremely cost effective.

The last thing I wanted to say is this is real now, so these units are already happening. I think Edison is going to speak about their unit. I've flagged a sort of likely conversion case in the Pio Pico unit and we'll talk about it.

Next slide.

And so, again, this sort of angle to think about this is that we're moving away from an internal combustion engine vehicle towards a fully electric vehicle but there has been this transition strategy of the plugin hybrid which helped. I think a lot of drivers managed that

transition. It gave them the comfort they needed and I think that's a relevant metaphor here. And so what we're proposing is this hybrid storage-plus-gas unit as part of this transition plan and I think there's immediate opportunities here.

Next slide.

So when we studied it the benefits are that you get a lot of cost effective RA. It's cleaner for local communities. And you get air quality and greenhouse gas benefits. So from the perspective of the state, this seems like a really obvious approach that we should strongly consider as low-hanging fruit.

Next slide.

I want to make sure I just a few examples here. And if you look down in San Diego there's a unit, Pio Pico. It's got some of the fancy GE technology. And you know, it's probably a plant that they want to keep, the CAISO will need in that area for contingencies and things like that, but you do have opportunities to add storage, sort of add this storage and hybridize it so that you cannot burn fuel, you can keep the air clean, yet you retain the sort of full capability of the fleet. And in these heat storms, you do have a

little bit of incremental capacity, as Steven -- as Kenneth mentioned earlier.

So next slide.

So I do hope there are questions and I would welcome that. I think what I would like to leave you with, though, is that this hybridization using storage is one of the only solutions that we're discussing today that helps all year round, not just in the heat storms, although it does clearly help in the heat storms too. It also fits with our clean energy and renewable goals of helping our gas units do lower pollution, lower GHG load following, or contingency service.

We have seen through the Edison filing that this is one of the most cost-effective tools available to the state. This is extremely cost effective, really high cost-benefit analysis that we should take seriously. And I think it is a critical part of studying our gas fleet, knowing which ones we want to retire and then knowing which ones we need, and then hybridizing them. So I would hope we can have discussion on this when the time is right.

And again, I really strongly recommend

this as something we see as a very clear, smart strategy for California, so thank you.

MR. BARTRIDGE: Thanks Alex.

I want to go back folks. I accidentally skipped over Mike Salvatore from Siemens.

So, Mike, if you're there, please, go ahead and jump in.

MR. SALVATORE: Okay. Good morning. Good afternoon everybody. I'm Mike Salvatore from Siemens. I'm the Manager of Combustion Turbine Models and Upgrades for Region North America. And you know, this is a challenge. I appreciate the opportunity to speak to the Commission and other folks about what Siemens is doing; right?

We operate plant flexibility services. That's the name of the game these days. We understand and remain competitive. The current energy market requires new operating profiles with increased flexibility. I can't say it any better than that.

Managing this energy transition to decarbonization and current legislation for lower emissions, we understand, can be very challenging. We feel that we have organized our

response scenario to walk alongside you on that decarbonization journey. You know, we have solutions tailored through the evaluation of requirements and tasks, operational limitations, what the folks need to know in terms of the asset owners, in terms of putting a technology within a certain envelope.

My colleagues at General Electric laid out what they can do with different frames and how far they can go and whatnot but you have to look at everything. You have to look at the entire envelope, whether it's a minor tweak to the system versus a -- call it a wholesale change of the gas turbine engine.

We understand benefits, you know, increased dispatch; right? Move the units up the curve. Improved profitability for the asset owners. And all this has to be done as we move towards decarbonization to maintain or improve grid stability because we understand that this is going to be something that has to be phased in over time. And we are, like I said, we are certainly with our customers at every step of the way in terms of our research and development, execution, staffing and whatnot, that we could

get there with you together.

So thermal performance upgrades, improving capacity, improving baseload capacity, improving turndown, improving other operational flexibility, faster ramping and all that, we have products and services for every frame in the fleet. And the general principle that we go by is we're basically now selecting technology from our advanced engines and fitting it into that envelope that I said. And we have quite a bit of experience. We've upgraded over 250 combustion turbines throughout the fleet over the last 10 to 12 years. And so we continue to learn and build off of that knowledge as we continue to develop other products that make the units more competitive.

Next slide please.

This is our -- we call it our radar slide here. And it goes from the current energy systems that are available and future energy systems. And we -- you know, this was (indiscernible) busy initially and there's lots of products and services scattered throughout these three pie pieces, if you will, to get us into the future. We understand that we have to

do this thing under a transition-type scenario working with you, looking at need-specific -- site-specific needs again and while maintaining grid stability or making sure that we can help you fill the gaps, as what's happening in the state of California.

Due to the time that we have here, the short amount of time, we only have time to, basically, cover a couple of examples to talk about the gas turbine upgrades, I have an example for that, and then the hybridization, the battery hybridization on existing plants.

So next slide please. Okay.

Here's an example of a plant. And I may have mentioned it, the upgrades can be done in whole or in part. When we make major changes to the operation of the units by modifying performance levels, adding in advanced technology, high-performance technology, better materials, better flow path, engineering, they were able to take these plants that were built 20 years ago and have them operate pretty close to our advanced technology that's being offered, our advanced (indiscernible).

This is an F plant, a 501F plant, where

we are upgrading a -- what we call an FD2 to an FD2 Version 6. And the 6 is just a designation that it is our advanced thermal package. And we addressed the combustion system that we were offering not only the better combustion system that could handle increased firing temperature, but also allows for maintenance flexibility, so allowing you to operate longer or extending your inspection intervals out as far as we can without creating additional fallout.

With the turbine, we have gone through the turbine and the compressor where we have put in advanced technology turbine blades and veins that are sealing. We have, specifically, a high performance last-stage blade in our turbine that helps drive this significant improvement that we see. (Indiscernible) direct their injection system, so this goes to the flexibility of operation, so this allows you to minimize rubs during hot and warm restarts, which a lot of folks are doing today.

The rotor is significant because we have taken the advanced technology and applied it to a configuration where it doesn't directly match. In other words, we basically had to develop a

hybrid design rotor that has the advantages of the advanced technology equipment but can fit into an existing unit.

But the key with the rotor is that it allows us to significantly increase starting and ramping capability. But you have to realize that when you're looking at the plant, it's beyond just the gas turbine, especially a combined cycle plant. You have to look at the plant systems, the steam turbine, the harnessing, the control systems and whatnot. So all that is looked at holistically. And in this case here we were able to provide significant improvement in performance.

Next slide please. Last slide.

And this is an example of SynerGen. They're called SynerGen.

Next slide please. Thank you.

Integrated battery storage systems, the generators are asked to do more and more. This is the way to optimize the use of renewable energy sources. Integrated battery energy storage system enhances gas-fired operation. Traditional battery projects just store and bring power to grid with the SynerGen batteries

installed within the plant footprint. And the BESS is integrated into the plant controls to optimize use of the battery with the gas turbine operation. And within those little boxes below we have products and services that align to each of those benefits throughout whatever way the asset is operating now and in the future.

It appears that I've run out of time on that but thank you for the opportunity, again, to present to the Commission and to the other folks and look forward to possibly responding to the Q&A later on this afternoon.

Thank you.

MR. BARTRIDGE: Great. Thanks Mike.

Next up we'll have Matt Garner with Roseville Energy Park. I understand that Matt's working through an outage right now, so I'm not sure how much time he'll have to offer comments, but let me turn it over to Matt.

MR. GARNER: Thank you, Jim.

Thank you, Commissioners, for your time. I appreciate the ability to discuss some of the upgrades we're pursuing at the Roseville Energy Park with you.

Right now, as we've heard from General

Electric and Siemens, there are lots of options out there to improve flexibility, capacity, and also to help with renewable integration as these plants move forward to a different California.

The City of Roseville and Roseville Energy Park are entering the energy imbalance market in the end of March 2021. And so our efforts have been to make it a successful entry to support grid stability locally in Roseville, as well as the Sacramento Valley, while improving those flexibility and capacity components within our power plant.

Not only do we have the Roseville Energy Park, which is 160 megawatts max capacity combined cycle gas turbine facility, we also have a very small peaking facility with two General Electric Frame 5s, MS5001Ps. It's a small peaking facility. And we're looking at addressing issues with that that could make it more valuable to the energy imbalance market as well.

We've got many items that we've looking to install to upgrade. But we are running into issues with item six on the list of questions that were given to us and that's lead times

because of the COVID situation that we're all facing.

Right now we are looking at combustion or advanced gas path upgrades to lower our min power, increase our maximum power, to get greater efficiency, roughly 0.06 percent out of each gas turbine, and also to increase combustion stability regardless of ramping and regardless of ambient conditions while we do the ramping up and down to support the integration of solar and other renewable resources. And we're planning on doing this, obviously, while remaining in compliance with all our current permit limitations.

All the CT upgrades, combustion turbine upgrades, and steam turbine upgrades can be done during our normal planned maintenance. We are looking at other upgrades to the facility. Inlet chilling, as was mentioned earlier, heat blankets for steam turbines to improve cycling and keep that unit warm when the facility is offline, those things can be done both online and offline as long as it's planned and done and staged correctly.

With any of these turbine improvements or

plan improvements that we look to doing, obviously, a thorough financial analysis is done. Because these are large capital expenditures, we need to ensure that the costs can be recovered from the market, so those are all evaluated.

I'm not going to go into great detail on the technologies because GE and Siemens both covered those very well, I think, and those are fairly standard throughout the gas turbine fleet. What can be offered by both of those companies, both have benefits that they can offer.

What I am going to highlight, along with the fact that we are looking to upgrade to support the renewable integration, is the fact that we are running into very, very significant real blocks and issues due to the COVID virus. We were looking at performing a lot of these upgrades in spring of the year. We're taking steps to get that done, including steps to amend our permits, et cetera. But what we're finding is that due to COVID, due to the lockdowns in Europe, due to the Canadian border being shut down, not only are we experiencing resource issues in getting components, getting labor, but our primary suppliers, which for the Roseville

Energy Park is Siemens, is experiencing issues as well. Once again, who would have thought we would be facing what we face today, but we are looking forward to successfully moving forward with that. It's just we have to --

MR. BARTRIDGE: Matt, we lost you.

MR. GARNER: -- overcome --

MR. BARTRIDGE: I think you're on mute. Are you still with us?

MS. GALLARDO: This is Noemi. I can still hear him.

MR. GARNER: I'm not muted. I'm looking. No, I'm not muted.

MS. GALLARDO: Go ahead and continue, Matt.

MR. GARNER: Okay. Thank you. Okay.

So we are working very closely with Siemens and our other suppliers to try to ensure that we can get the resources here, components, people. And once we have the people onsite, we're taking, obviously, great efforts to make sure that they can work safely with proper distancing, PPE, and disinfecting protocols in place.

Once again, I'm not going to go into the

specific upgrades to the gas turbines because they're pretty common across the industry and GE and Siemens already covered both of those.

That pretty much takes care of what I wanted to present and what I want to discuss. Once again, I appreciate your time.

MR. BARTRIDGE: Great. Thank you, Matt.

Next up we'll hear from Ross Gould with SMUD, Sacramento Municipal Utility District.

MR. GOULD: Good morning everybody. My name is Ross Gould. I'm the Director of Power Generation here at SMUD. And I actually have a case study that seems to be pertinent to the discussion today. So I'm going to talk about the Cosumnes Power Plant advanced gas path upgrades.

So next slide please.

Okay, so in June of 2017, there was a heatwave in June that wasn't particularly notable, except for the fact that we had some externalities that made it challenging. So going into that summer, our calculated load-serving capacity, load source adequacy calculation was about 3,350 megawatts. Our previous all-time high load, which was in 2006, was right at 3,300. And since that time, since 2006, the load had

been hovering around 3,000 megawatts.

So there's a lot of things that go into the calculation for procuring capability. But in real and general terms, you can stand back at the end of the day and look at the calculation and if you're one-in-ten forecast plus ten percent, then you should be okay, and that should put you in the ballpark.

So in summer of 2017, several outages kind of combined to reduce our load serving capability. We had one hydro facility that had mechanical issues. There was a neighbor facility that was de-rated due to mechanical issues, and the California-Oregon Intertie Transmission Line was de-rated due to maintenance work, so our load serving capability was now down to about 3,100 when the June 19th heatwave came in 2017 and SMUD's system peak load reached 3,149, which was greater than our current load-serving capability after those de-rates.

So we had four consecutive days above that record. And it required us to use some mitigation tools and to arm the air conditioning load management system and some other systems that allowed us to get through that summer. So

the system worked. We did get through. But afterwards we always looked back and we reexamined our assumptions and calculations and came to the conclusion that we needed to increase our load-serving capability very quickly. So we kicked off several projects to do that, capacitor banks, some transmission bottlenecks, and then this advanced gas path at Cosumnes Power Plant.

The next slide please.

So the Cosumnes Power Plant is a 500 megawatt combined cycle gas turbine facility with GE technology, GE 7FA two-on-one. It's been in operation since 2006. And both those gas turbines were actually due for a major overhaul and that's what makes this upgrade work. We had already been studying the modifications and upgrades and talking to GE about whether it makes sense to do it. And when the need came together with the opportunity, we took advantage of the advanced gas path upgrade opportunity and increased our load-serving capability by 56 megawatts for the plant, increased our heat rate by two percent, and the return on investment was really attractive, less than two years.

Next slide please.

What actually happens inside of an advanced gas path upgrade, you know -- and GE calls it advanced gas path, Siemens calls it Si3D -- they're very similar conceptually. All heavy-duty gas turbines tend to have this upgrade potential so that increased thermal barrier coating on the blades improve sealing technology to make sure that the gases go through the system and not around it, and then upgraded materials to absorb some of that extra -- the pressures and the temperatures. All of that allows you to build on a combustor that burns more gas more efficiently, so in this case the (indiscernible) project increased output, increased efficiency.

So next slide please.

So what does it actually look like? Here on the right there's a picture of the upgraded gas turbine rotor being flown into place. And then on the left is the, actually, the installation of the transition pieces that connect the combustors to the hot section of the gas turbine. And I just put these in here because everybody likes the shiny stuff.

I will note there's a chart down there that shows the actual output upgrade result.

Generator net output for one gas turbine went from 174 megawatts to 196 megawatts, which is a little bit more than a 13 percent increase, and that meant it's tolerant. And the net heat rate improved by 2.2 percent.

So of note here is that we weren't able to test for about six months after the upgrades were complete. That was due to the timing of the air permit.

So next slide please.

And I've been rushing a little bit because this is what I wanted to get to. Some of the reasons why this can be challenging is, first of all, prorating. When you increase your potential to emit you have to go through a best available total technology review and a Title V process and that takes time.

We approached the Sacramento Metropolitan Air Quality Management District and we attempted to get an accelerated review of our Title V permit. We weren't actually able to get that. But what we did manage to do was strike an agreement with the Air Board that we would be able to implement the upgrade and not turn it on, but we implemented the upgraded during our

overhaul and then ran it at a lower power level until the Title V permit was completed.

There's also considerations with the California Energy Commission decision. You have to do a permit to amend and go through that process but the CEC was amazing during that process. They were completely committed to helping us reach our goal at the end point.

And then there's lots of balance of plant impacts. If you change out the gas turbine, (indiscernible) at the middle of the plant, then everything else changes, you know, water usage, HRSG pressure limits, steam turbine flow restrictions, NERC compliant, all kinds of stuff that you have to do, so you have to completely broaden your perspective on what you're looking at when you consider these upgrades.

So that's my presentation. Thank you.

MR. BARTRIDGE: Thanks Ross.

Next we'll move to Frank Messineo with Burbank Water and Power.

MR. MESSINEO: Good morning. My name is Frank Messineo. I am the Power Production Manager with the City of Burbank Water and Power. And I'd like to discuss some enhancements we're

working on for Magnolia Power Project today.

Next slide please.

So Magnolia Power Project is a Southern California Public Power Authority project. It has six participant cities, including Anaheim, Burbank, Cerritos, Colton, Glendale, and Pasadena. And Burbank is also the operating agent for the project.

It's a combined cycle gas plant that includes a General Electric Frame 7 combustion turbine and a General Electric A14 steam turbine.

Magnolia Power Project was commissioned in 2005. And it was intended as a baseload power plant.

Next slide please.

So some of the challenges that we've seen over the years is increase in renewables and integration of renewables has decreased the need to operate at baseload. And it has increased a need for greater flexibility. And some of the issues that we face is our operating range is 165 megawatts to 300. The ramp rate is about five megawatts upward per minute and two-and-a-half downward. And we're limited to about five starts per month. It's a highly efficient unit but it's

not something we could start and stop rapidly. It takes hours, not minutes.

Next slide please.

So we've been looking at this for years and evaluating different technology. We ultimately decided to enter an agreement with General Electric for some combustion turbine enhancements that would help us address our concerns. We went with two upgrades. One is called an overboard bleed system. And the other is a new product for this specific turbine and that's axial fuel staging.

We implemented and tested back in March of this year. And the axial fuel staging being a new product, we determined that -- well, it was successful, I should start with saying that, that it achieved a reduction in turndown. However, we did identify a need to increase durability of some of those components, so that's something GE is working on, and we'll be installing the final product in 2021. But what we're looking at is receiving an enhanced operating range and increase of turndown of 74 megawatts. So we'll be able to go down to 91 megawatts as our minimum output or, possibly, better. And the ramp rate

will be at least double of what we have now.

So one of the main things that a few of the others have talked about, these type of projects really need to be planned several years in advance for permitting, as well as manufacturing. And what really makes or breaks projects like this is the ability to align them with existing major maintenance. So if you're able to do this at the time you were planning to do an overhaul you have avoided costs; right? So that makes this more attractive. You're able to divert money you were going to pay for like-in-kind replacement parts to an enhancement.

And next slide please.

Oh, sorry. That concludes my presentation. Thank you.

MR. BARTRIDGE: Thank you, Frank.

Next up we'll hear from Matthew Zents from Southern California Edison.

MR. ZENTS: Good morning, Commissioners and panelists. Thank you for your time today. I'm Matthew Zents from Southern California Edison. I was the Project Manager that oversaw all the work to convert two of our peaking plants from a standard peaking plant to a battery

turbine hybrid. This is General Electrics CGT offering enhanced gas turbine.

These plants were originally put in service in 2007. And then the upgrade was done between 2016 and 2017. In addition to the battery, we actually upgraded our emissions control system as well. The reason why we did that is when the plants were first built they could, the way our air permit was structured, they -- we could ramp up and down through the range and meet our emissions permit, we just couldn't hold at anything below, pretty much, pmax (phonetic) and still be emissions compliant. So we upgraded our SCR catalyst and replaced our CO catalyst, and then changed the ammonia from 19 percent to allow the ammonia to do more of the NOx reduction and, you know, less NOx water.

So in terms of lead times, you know, this isn't a project that you can do in a standard one-week peaker outage. You can, however, do the cutover in that work, which is what we did.

But in terms of lead times, we were seeing four months for invertors, transformers and switch gears, approximately six months for the NOx and the CO catalyst material.

Construction of the battery was approximately four months which included one month for the BESS commissioning and then approximately three months for the emissions control system upgrade, which included one week for testing and commissioning, including the gas compressors, the ammonia system, and the emissions reduction unit.

Next slide please.

So these are -- this is just a quick overview of some of the objectives we had and the results. And, you know, we went from a standard peaking plant, which is pretty much non-spinning energy to spin and rev and rev down, in addition to energy. So we converted our utilization from, you know, ten -- roughly 10 percent to, essentially, 100 percent because, you know, in spin we're providing the full capacity of the gas turbine without burning any fuel. So in essence, we're on all the time.

So you know, from getting paid through the market, it's a much better return on investment for our peaking plants being the hybrid, you know, rather than just the standard peaking plant. So obviously, we really increased our market services. We increased our asset

utilization. In the first year of operation we have data that shows that our fuel savings was reduced -- or increased and our emissions were reduced. We actually had starts and run hours about half of what we experienced at our three non-hybrid peaking plants.

Decreased water consumption. Again, we really dialed back the NOx water in the combustor, so that increases the life of the turbine because you're not putting all that NOx water in there, you know, having, you know, an erosion effect on your thermal barrier material coating.

And our decreased maintenance, I put, "Not met there." The reason being is we're in the process of pulling out our turbines and changing out hot sections and doing, you know, some major overhauls. And the reason for that is, you know, these things are pretty heavy-duty service. And so the expectation going forward is, once they return to service with the different operating profile, we'll get a lot more, you know, hours out of the engines and be able to reduce our maintenance costs. So we fully expect to realize that. It just didn't

happen in the short term.

Next slide please.

So I wanted to -- I put this slide in there to let the audience know some things that happened to us that we didn't expect.

So the first bullet there, when we put our battery online we had a ton of drop response events, upwards of about 600 a day. And what were finding is our batteries were getting drained every day because they kept getting pinged by the system. And so, you know, we'd end up having to start the turbine just to charge the batteries which, you know, the Independent System Operator is wondering, you know, what we're doing and why we're doing it because we weren't called to dispatch. So it took us a while to figure that out. And it was resolved with tuning.

So anybody that puts a battery online, you know, just be aware that there may be some things that happen that you're not expecting.

The second thing that we didn't expect were these unusual dispatches on our gas turbine. So you know, we would get some very unusual dispatches, for example, like 12 megawatts for seven minutes which, you know, obviously we went

from, you know, going from, say, 47 to 49 megawatts, you know, not much of a range between pmin and pmax to being able to dispatch anywhere between zero pmax and then everywhere in between. So we didn't really expect that.

And I think the takeaway here is that for future projects you may want to consider a bigger battery so that you're not running your turbine in these little, short runs. And a lot of this, I think, is coordination between the operator and the Independent System Operator. Because, you know, again, these were the first two hybrid plants anywhere in the world, so I don't think anybody really knew what to expect in terms of how they'd run and be dispatched. So this was something very strange that we didn't expect.

And then the last bullet that I want to talk about is the mismatch between the Edison data and Independent System Operator data which resulted in a number of these, what we call, a clawback award. And you know, we were, basically, seeing where the Independent System Operator couldn't really tell that -- they couldn't tell if the plant was on or off, so they couldn't see the power system stabilizer or the

automatic voltage regulator or this Yukon (phonetic) bit because, you know, obviously, it -- if it doesn't look like the unit's on it can't be dispatched.

You know, prior to these projects we, you know, were in, you know, a dispatch mode where we'd call the operator and they would dispatch it. We converted them to automated grid dispatch. So we had some issues to work through with our rate telemetry and so that, you know, both the System Operator and our operators were synced so they knew when the units were on and off.

So these are things that, you know, as lessons learned, you know, work very closely with the System Operator so that you can work out some of these unusual bugs.

And that concludes my presentation for this morning. And I'd like to thank everybody for the opportunity to speak.

MR. BARTRIDGE: Great. Thank you, Matthew, and thanks to all panelists this morning for the great discussion.

We'll hold questions and discussion until after we've heard from Panel 2, at which point

we'll first turn to Commissioners, followed by public comment.

Here's the list of the panelists for Panel 2: Barbara McBride with Calpine; Jan Smutny-Jones with Independent Energy Producers Association; Dennis Jang with Bay Area Air Quality Management District; John A -- sorry John, I don't want to try with that one -- with San Diego Air Pollution Control District; Tom Jordan with San Joaquin; Amir, same to you, sorry, Amir; Eric Knight, Dawn Weisz, and Deb Le Vine, that's Energy Commission, Marin Clean Energy, and California Independent System Operator.

So with that, let me turn it over to Shawn Pittard, Deputy Director of the Siting, Transmission, and Environmental Protection Division, who will moderate Panel 2.

Thank you.

MR. PITTARD: Hi there. I don't see my video. Am I good?

MS. GALLARDO: You're good, Shawn.

MR. PITTARD: All right. Thank you.

Hello. As Jim said, my name is Shawn Pittard. I'm the Deputy Director for the Siting,

Transmission, and Environmental Protection Division at the CEC. We've implemented the Power Plant Program for 45 years now and have conducted landscape-scale environmental and land use planning studies to support renewables development and transmission line siting for the past 20.

We all know that the CEC has jurisdiction over thermal power plants greater than 50 megawatts. We provide regulatory oversight for the entire lives of these projects. This includes permitting, acting as the state's chief building official during construction, conducting compliance monitoring and enforcement during operations, and decommissioning at the end of the project's life.

Some quick stats. The Commission has reviewed 240 applications to build power plants in California. It's approved 128 of those 240; 106 have been constructed. Currently, we oversee 79 operational power plants. That's about 28,000 megawatts of electricity, 25,000 megawatts of which is natural gas.

So our work puts us in close contact with power plant owners and operators, the Air

Districts, the California Independent System Operator. Representatives of those entities and Marin Clean Energy make up the next panel.

On our first panel -- and thank you all, that was a wonderful panel, that was great, thank you very much -- on our first panel we heard about potential technology improvements and their benefits. This panel will help us understand the opportunities and challenges associated with making those improvements.

So we'll start with Calpine Corporation. I'll turn first to Barbara McBride.

And, Barbara, could you share your thoughts with us?

MS. MCBRIDE: I could if I got off here; right? So hi. I'm Barbara McBride. And I've been at Calpine almost as long as Shawn has been at the Energy Commission.

But I wanted to thank the CEC for putting this together. I think this is a very important topic. And you know, I think it's very timely to talk about these upgrades and how we go forward.

So next slide.

So this is, basically, Calpine at a glance. Calpine serves wholesale and retail

customers in 24 states, Canada, and Mexico. We are the largest geothermal and combined heat and power producer in America. We have 6,000 megawatts of combined cycle natural gas facilities in California, 500 megawatts of peaking capacity, and 725 megawatts of baseload renewable energy at the geysers.

In addition, we just got permitted a solar-plus storage facility in Kern County. And we do have several other battery storage facilities that we -- that are in various stages of development.

In addition to that, we are piloting two carbon capture and storage pilot plants at our Los Medanos Energy Center.

Okay. Next slide.

The technologies that we heard about this morning, these are the technologies, really, that Calpine went through to determine what upgrades we could do to get more -- or to get 2021 incremental capacity. And we went through a step-by-step process for each facility, looked at each facility, looked at the upgrades, and saw what made sense and what didn't make sense.

What we came up with is we really think

the combustion turbine upgrades are the preferred technology because of the incremental megawatts achieved and the efficiency improvements that we get with the extra benefit of producing less emissions for each individual megawatt. These improvements, however, do require significant capital investment. And we do need to make procurement commitments on these combustion turbine upgrades by December of 2020.

In addition, we did -- I know we talked about, a little bit, about the chillers this morning. We looked at chillers and why they weren't really a viable 2021 technology is because of the engineering and procurement. It takes about a minimum of 18 months. And our facilities, also, already have fogging, so the incremental megawatts that you get from the chillers is not as substantial as it would be if we didn't have those fogging.

Okay. Next slide.

In addition to technology selection, what we did is we looked at permitting path. We looked at outage schedules. We looked at limitations due to LGIA constraints on our analysis. In the end, we came up with several

possible options totally about 90 to 95 megawatts of capacity that we could put in by the summer of 2021.

In addition to this, I wanted to give a great shoutout to CEC staff and the Air District staff for coordinating over the last couple of weeks and talking through what is the permitting path for doing these upgrades. Because, mainly, what we looked was combustion turbine upgrades and p-firing (phonetic), and so they were very good about discussing what the permitting path was and how we get this completed, so thanks to you guys.

All right. Next slide.

So here's what we came up with for Summer 2021. We, as we said in the last slide, we looked at the possible technologies. We determined that -- we went through the process and looked that there was interconnection or transmission upgrades that were necessary for these specific facilities that we came up with. We confirmed the vendor available with GE and Siemens. We submitted air permit applications for these combustion turbine upgrades. And in addition, we are also having conversations with

the CAISO to see if more outages could be extended, accelerated, and working with them on timing on that.

The big remaining issue that we have is procedure. These all -- all these upgrades require significant capital investments, and when you start considering accelerating outages and outage extensions, so that just adds to the cost of putting these upgrades in place by the summer of 2021. So basically, what we need to do is make all these procurement requirements by December of 2020 so that we can actually install these in our outages in April and May of next year.

And so Calpine is willing to make all these expenditures. But we need sufficient contracting to cover the incremental costs securing these resources. So like I said before, we need to make these commitments by December, so we need to have a clear procurement path over the next couple weeks.

So next slide.

So in addition to 2021 capacity, we looked a little forward to see what we could do in 2022, 2023, and 2024. So looking past 2021,

we can -- we are also looking at additional combustion turbine upgrades that we could do. And these were combustion turbine upgrades that we couldn't do for summer of 2021 because of either outage constraints or LGIA constraints. And so -- but we are continuing to look at those to see what we can do for, potentially, 2022 and 2023.

In addition, we do have a potential project at our Pastoria Energy Facility, which is highlighted here. It's an additional 200 megawatts of capacity that we can, basically, bring on by either 2023 or 2024, depending on what the permitting path looks like. This is actually adding an additional turbine to our existing facility. We have, you know, we have the land. We have the -- we have -- you know, there's no required additional reduction credits. It's not in a disadvantaged community. So this is actually a great project for bringing on an additional 200 megawatts by late Summer 2023, 2024.

In addition, for further in the future, like I said before, we do have two carbon capture and storage pilot projects at our Los Medanos

Energy Center. And we really think the CCUS is a retrofit for the future. They're very economical biotechnologies that can provide clean and firm power.

And I think that's all I have. And I look forward to talking further and answering questions on this.

MR. PITTARD: Great. Thank you, Barbara.

Our next panelist is Jan Smutny-Jones from the Independent Energy Producers.

MR. SMUTNY-JONES: Thank you very much. I appreciate the opportunity to participate in today's panel. And I want to thank Commissioner Douglas, President Batjer, and Commissioner Randolph, and Chairman of the Energy Commission, as well, for participating in today's panel.

IEP, obviously, represents a large number of different types of resources in California, including utility-scale solar, geothermal, wind, biomass, battery, long-duration storage, as well as most of the independent gas fleet. And we believe in a diverse portfolio of resources that are brining different technologies with unique attributes to the California grid.

The events of August are a big reminder

that we have the need for this mixed portfolio. And I think as the data shows that at net peak on August 15th there was about 27,000 megawatts of gas generation online, meeting the needs of the grid. That was about 60 percent of the supply we provided.

So today the discussion has centered on meeting -- how to use this existing generation in a way that can be added to. And I want to underscore the point that we're not talking here about building, you know, brand new power plants all over the state of California but, pretty much, squeezing out efficiencies on the existing fleet that's out there.

I think the previous panel has done an excellent job, and Barbara did a great job of putting forward some of the challenges, but opportunities that are there. I think the SMUD presentation, my hometown utility, did a good job with a case study in terms of how these improvements can actually assist the grid and actually have a positive environmental impact as well.

So I'm going to focus, basically, on a couple of other quick things.

First of all, I think as you've heard this morning, there are sort of these subsets of things that can be done immediately, some done by summer of 2021 and some longer term. So there are some operational considerations that can be made with respect to increasing firing temperatures, et cetera. This will have an impact on the equipment and may require air quality permit reviews. There are sort of a list of different types of equipment upgrades that could be made, some which may be able to be made in 2021. I think as Barbara indicated, and I've heard a similar thing from my other members, other types of improvements, however, may bleed over to 2022 and beyond.

I think it's important to look at all of this in the consideration. We do have other challenges in the system, you know, as we're trying to meet our goals with respect to a carbon-free future.

Diablo Canyon is the first unit designed to go off or scheduled to go off in 2024. We are, effectively, in 2021. We've got 29 days until we bring in a new year. And I think I probably can speak for the entire group that's on

this panel today, that the sooner we get to 2021 the better.

We also have a situation where the once-through cooling units that have been, basically, carried over beyond their retirement dates are also designed to come offline. There may be some -- there are some opportunities to replace some of that generation but that is happening.

And then we have the potential for extended droughts, which is something I recently heard about. And the concern, of course, is that we've experienced that earlier in this decade and to had an impact on how the gas fleet operated.

So the key here is regulatory issues, the timing. We need a procurement of these resources, or clear signals, from the PUC pretty rapidly as to whether or not there is a desire to make these investments in these plants. And that also entails a cost recovery mechanism. Both of these are generally debated. But my hope here is that we can utilize previous experiences where we have added peaking generation in 2002 time frame, and then again in the late 2000s to, basically, add additional resources, so that's key.

This has to be done consistent with

environmental regulation. Obviously, the Energy Commission has a big role in this, ensuring that the improvements that are made here are consistent with their licensing requirements.

And then the air quality issues, which are very significant, coming up with respect to -- and there's panelists speaking -- to make sure that these units which are, you know, heavily regulated under California Law, both with respect to criteria pollutants and greenhouse gas pollutants, ensuring that these, basically, meet the requirements, that these upgrades are with their permits and, if not, adjusting the permits in such a way that allows them to move forward.

Time constraints are we need the approvals. We need to secure, you know, a plan to schedule outages for these units. And a CEC decision that these upgrades would be, hopefully, within existing licenses. If not, a recent appellate decision may have an impact on the timing of how some of these improvements can be made.

So the cost recovery issue is key. And again, I think it's important that -- critically important that we, basically, improve our system

in a manner that's consistent with our ultimate goals.

The quickest way to set back our drive towards a carbon-neutral future is to undermine reliability and affordability. So I think California ratepayers are expecting us to be able to keep the lights on under all conditions. And my membership, IEP membership, will continue to do our part to make sure that that happens.

Thank you.

MR. PITTARD: Great. Thank you, Jan.

Now we're going to hear from representatives of four Air Quality Management Districts. We'll start with Dennis Jang from the Bay Area Air Quality Management District.

Dennis?

MR. JANG: Good morning everybody. I'm a Supervising Engineer at the District. And my group handles the power plant permits.

In terms of -- I was just going to say, we recognize the importance of these improvements, particularly in light of what happened in August with the Governor's emergency order which resulted in some facilities going offline and operating backup diesel generators,

so we certainly don't want to see that happen.

I'm just going to talk a little bit about how to expedite the permit process. I think, obviously, one thing is to have as much lead time as possible. And generally, meeting -- pre-meeting prior to submitting an application is important. We can determine, first of all, whether an application is even necessary. Sometimes, I think, it could be handled administratively, particularly the flame temperature software improvements.

In terms of what we want to see in an application, obviously, we want to know, what are the emissions' impacts? Are there increases? We're particularly interested in increases in fuel use capacity which, obviously, is an increase in potential to emit. We want to know, are there going to be any changes in permit conditions? Is the CEC license going to be -- require changes or approval? The Title V permit, whether that's going to be affected? That, as was mentioned before, that's a long lead time there.

So overall we just feel like the more information provided as soon as possible the

sooner the permit can be issued.

That's, basically, all I had today.

MR. PITTARD: Terrific. Thank you, Dennis. Really appreciate your participation.

Next we'll hear from the San Diego Air Pollution Control District.

John, I know that Jim didn't take a shot at your last name. I think I might take a pass, as well, but kick it over to you, John.

MR. ANNICCHIARICO: Okay. Thank you. Can you see me at this point?

MR. PITTARD: Sure can.

MR. ANNICCHIARICO: Great. Well, thank you. My name is John Annicchiarico. And I'm an Engineer at the San Diego County Air Pollution Control District. And so I also wanted to thank the CEC and the panelists for a very informative discussion so far.

I also want to echo some of Dennis's comments on what's important when we're taking in applications. And we'd really love to have early conversations and pre-application-type meetings so we can understand the project and do a little research on it, and so we can inform prospective applicants of what's needed.

Next slide please.

So here at the APCD and I just wanted to touch on a couple. I have a few slides on how we achieve and maintain our Ambient Air Quality Standards. But I also wanted to mention that all of our programs, all of our rules, they have cost effectiveness built into them. And so our downstream permitting actions that I'm going to discuss, they carry that through.

Next slide please. I can't see the slide yet. Oh, here it comes.

Okay, so this slide, it shows that we're decreasing ozone-forming emissions on the left. And on the right we have our ambient ozone levels that have been measured. So I just wanted to point out, we do -- we have shown tremendous progress. But we do have some improvements needed to get down to the levels that the state and the EPA had required of us.

Next slide.

So here you can see that we are not in attainment for either the state or the federal eight-hour Ozone Standard, or the state standards for PM10 or PM2.5.

Next slide. So we can move on to the

next slide.

So this slide just shows that we do anticipate, with the plans that we have, these are predictions through CARB's model of our air quality data, that we anticipate we will achieve attainment for the Ozone Standards in 2032.

Next slide.

So as I said, my role at APCD is in permitting. And turbines are -- and power plants are just one of the many different types of processes and equipment that we permit. Here's some data on the number and the different sizes of turbines that we have.

Next slide.

So here are two actual examples of the hot gas path permitting actions that we've had. So, for example, one, which was a more simple process for us, for APCD, there was an increase in the firing temperature. But the firing rate did not go over what was the limit on the permit. And, also, there was no megawatt output increase. Significantly, there was no increase in the emissions. And because of all of that, this was, for us, a very short review period. And it took about four months to approve this.

Example number two did have an increase in the firing rate, also, megawatt output increased. We did work with the applicant for taking voluntary permit limits that lowered some pollutants. But we weren't able to do anything about the increase. There was an increase in SO2 emissions. This ended up being a significant modification to the Title V permit but we did get through this. We did approve it. It took about 15 months for that approval process.

So that's my presentation. Thank you.

MR. PITTARD: Thank you, John. That was very, very helpful. Much appreciated.

Let's move to the San Joaquin Valley Air Pollution Control District.

Tom Jordan?

MR. JORDAN: Good morning. And thank you for including us in this discussion. I think one of the messages that's been shared is, as far as air quality permitting goes, the earlier you can talk to the Air Districts the better in making sure that we can be responsive to your projects and move them forward.

I think Dennis and John did a good job of talking about the permitting process. I wanted

to talk a little bit about what makes things slightly different in the San Joaquin Valley.

Most of you are probably aware that the valley faces some pretty significant air quality challenges under the Federal Clean Air Act. Because of our topography and meteorology, we are classified, along with our partners to the south, South Coast, as extreme nonattainment under the Federal Clean Air Act, which is the highest level of nonattainment you can be. Along with that designation comes more rigorous requirements when we permit projects, lower thresholds where projects are considered Title V facilities, requiring that more extensive review.

So the goal, as I understand it, of a lot of these upgrades is to increase power output. And at these major source facilities here in the valley that's, more than likely, going to trigger new source review at those facilities, require review of whether those facilities have backed in place best available control technology and, if they don't, modifications would have to be made to meet those requirements.

And then, also, depending on the facility's situation, and it's very facility-

dependent on potential to emit versus actual emissions, and some things that would need to be -- you know, we'd need to have discussions with the facility to go into there's a good chance that offsets may be required, as well, for these modifications.

So I think, going all the way back to Ross Gould's presentation earlier, the earlier the better. If you're thinking about making modifications, especially if those modifications are intended to go online in 2021, those discussions need to start happening now. And before a permit application is submitted our staff is more than happy to meet with folks and talk to them about any potential requirements and the likely path to a successful permit application.

We do have a process in place here in the valley where people can pay for expedited processing of permits. They basically are paying for overtime work outside of normal hours to get their permit processed so that is an option. But as has been mentioned, if you trigger Title V and federal permitting requirements, some of those things just take time. There's noticing

requirements. There's other things that make that process a longer process than if they simply fall under our local permitting requirements.

So I guess my message would be we're, you know, we're happy to help and to move projects forward as quickly as possible to help meet the energy requirements of the state. But there are, you know, processes and requirements in place that we just can't accelerate any faster than they can happen. So if you're thinking of making upgrades, especially in the next year, you need to be talking to us now. And we'd be happy to help you move your project forward.

So thanks.

MR. PITTARD: Great. Thank you, Tom.

Next we have a representative from the South Coast Air Quality Management District.

Amir?

MR. DEJBAKHSH: Good morning. Sorry. I was un-muting. Good morning, Commissioners, CEC Staff, and the panel members. My name is Amir Dejbakhsh and I'm the Deputy Executive Officer in charge of Permitting and Engineering at South Coast AQMD. I would like to thank you for inviting us to be part of this workshop.

Before going over some of the challenges that we have in issuing and modifying permits, I would like to start by giving you a short background on who we are and our permitting program.

Next slide please. Thank you.

We're one of the 35 Air Districts in California. And our jurisdiction includes non-desert portions of Los Angeles, Riverside, and San Bernardino Counties, and all of the Orange County in Southern California. Our jurisdiction is home to more than 16 million people in an area of, roughly, 11,000 square miles. We regulate more than 27,000 facilities which includes 360 major sources. And we have the worst air quality in U.S., next to San Joaquin to our north, when it comes to ozone and particulate matter of 2.5 microns or less. We have 22 power plants in our jurisdiction, both baseload and peaker plants, with a combined output of more than 12,000 megawatts.

Next slide please.

We are co-air permitting authority with CEC for power plants that can generate 50 megawatts or more. And we are the air permitting

authority for all power plants within our jurisdiction.

Power plants, when they file their applications to get a permit with us, fall under our Title V and/or our RECLAIM Permitting Program.

Title V Permitting Program is a federal Operating Permit Program that USEPA has developed as part of a Title V of the 1990 Clean Air Act amendments. Facilities that are a major stationary source of toxic and criteria pollutants and are subject to Acid Rain Program, or subject to certain New Source Performance Standards, NSPS, or National Emissions Standards for Hazardous Air Pollutants, NESHAPs, are required to be under this program. The centerpiece of a Title V program is a Title V permits which consolidates and replaces all of the air permits for an individual piece of equipment at a facility and contains all federal, state, and local air regulatory requirements under one document. Title V permits allow for federal and citizen enforcement, gives USEPA review and veto authority, and enhances public participation.

In South Coast AQMD, because of our ozone extreme nonattainment status, we have a lower threshold for major sources than other areas which results in more facilities requiring a Title V permit.

The second program that power plants can fall under in our jurisdiction is our Regional Clean Air Incentives Market, or RECLAIM, Program. RECLAIM is our Emission Cap and Trade Program that allows facilities to meet annual emission targets for oxides of nitrogen, NOx, and sulfur of -- oxides of sulfur, SOX, in lieu of complying with our command and control requirements.

Out of the 32 power plants that I mentioned earlier, 2 are solely in our RECLAIM Program, 6 are only in the Title V Program, and the remainder, 25 facilities, are in both Title V and RECLAIM.

Next slide please.

After we receive an application and deem it complete some of the important requirements that the facility has to meet are satisfying California Environmental Quality Act requirements. A proposed project must meet our new source review requirements which includes

installation of best available control technology, or BACT, if there is an emission increase. Show true air quality modeling analysis that potential emissions from the proposed project will not cause an exceedance of Ambient Air Quality Standards and provide emission offsets if necessary.

A proposed (indiscernible) project must also meet our toxic NSR requirements for cancer risk, cancer burden, and noncancerous hazard indices. They also must meet the applicable prevention of significant deterioration for criteria emissions, PSD, New Source Performance Standards, National Emissions Standards for Hazardous Air Pollutants, and any other federal regulations, such as Acid Rain Program.

We also require a 30-day public notice under certain circumstances during which public can provide comments on a proposed permit.

As I had mentioned earlier, any permitting action to a Title V permit, with the exception of administrative changes, requires USEPA review. And USEPA has 45 days to review and comment on any proposed Title V permit. And of course, depending on the applicable regulatory

requirements, they have to ensure the proposed permits have the appropriate monitoring, testing, reporting, and recordkeeping requirements.

Next slide please. No. The one before that please. Can you go back one slide? Thank you.

So what are some of the permit challenges that can delay issuance of a permit?

When we evaluate a new project or when we modify a permit, we have to evaluate all applicable requirements based on the most stringent regulations, which are often very complicated, not only to the facilities but also to the public. For example, if a facility wants to change an operating condition that results in an emission increase the facility would be subject to different new source review applicability requirements for different pollutants if they are under our RECLAIM Program.

The other challenges that can delay issuance of a permit are review by other agencies and public participation. As I explained earlier, we have to submit our evaluation on our proposed permits to USEPA for their 45-day review period if the facility has a Title V permit. And

we may have to do a 30-day public notice if necessary. Our regulations also require notifications to any state that may be affected by a proposed Title V permit. And we have to notify our other state regulatory agencies when applicable.

Typically, to streamline the process, if a project requires both a public notice and USEPA review, we start the public notice and we ask EPA to start their 45-day review process at the same time. However, if we receive and have to respond to public comments the USEPA requires submittal of comments and responses to them, which can result in additional delays.

So what is our recommendations to facilities? Basically, the same sentiments that was already discussed. We ask facilities to file their application as soon as possible and provide us all the information that we need so there are no requirements for back and forth with the facilities. And we request -- and, also, facilities can also request us to expedite the permitting process by utilization of the permitting -- expedited permitting program that we have in place. And we, finally, are committed

to work with our power plant operators to ensure that projects are prioritized and move quickly with their permits, if there are no legal constraints prohibiting us from granting permits.

Thank you. That concludes my presentation.

MR. PITTARD: Great. Thank you very much, Amir. And thanks to all the Air Quality Districts for their participation today.

Next we'll go Eric Knight with the California Energy Commission. He serves in the Siting Division and is our Environmental Office Manager.

Eric?

MR. KNIGHT: Thank you, Shawn. Can everybody hear me?

MS. GALLARDO: Yes, we can.

MR. KNIGHT: Okay. Good. Thanks.

Good morning, Commissioners, fellow panelists, and guests. My name is Eric Knight. I'm the Manager of the Environmental Office and the Siting, Transmission, and Environmental Protection Division at the Commission. My presentation is going to cover how the CEC would process proposed incremental efficiency and

reliability improvements at CEC-licensed gas plants.

Next slide. Oh, thank you. That slide. I'm sorry. All right.

So per the Energy Commission's regulations, which are found in Title 20, California Code of Regulations, Section 1769, the incremental efficiency improvements could be considered a change in the project's design, operation or performance requirements, which are specified in the Commission decision which is the certificate or license for the facility. If the improvements result in a project change the regulations require the project owner to submit a post-certification petition to the CEC for approval.

As you heard from Ross Gould at SMUD, the advanced gas path that the Cosumnes Power Plant, which was licensed by the CEC, required a petition to amend.

Adding battery storage, like, I believe, Alex Morris with CESA had mentioned a possible at the Pio Pico Plant, which is another facility licensed by the Commission, that would most likely, also, require a petition.

So a petition should contain a complete description of the change. It needs to discuss the environmental effects of that change and any needed mitigation. Often times the conditions of certification already in the license will address any environmental effects but that's not always the case. And then the application needs to discuss the project's continued compliance with applicable Laws, Ordinances and Standards, which we often refer to as LORS.

However, there are some upgrades that maybe we would -- that would be more akin to maintenance that is in-kind equipment replacements, swapping out one piece of equipment for the functional equivalent piece of new equipment. For those, we would say, that's not a change in the design operation of requirements. And in those cases a petition wouldn't be required. What Staff would do is review that, issue an authorization letter which would be limited to the scope of activities that were described to us. There would be, obviously, a requirement to adhere to all existing conditions of certification. And there may be a need for a delegate chief building official review of the

upgrades.

So we've developed an intake form, a questionnaire, which can help plant owners figure out which course is required. And as Dennis Jang with Bay Area mentioned, we are also happy to meet with project owners in advance, remotely that is. And we can provide examples of high-quality petitions that have been submitted by other developers.

So if a petition is required, there are two paths to approval, either at Staff level or by the Commissioners at a business meeting or other hearing.

So Staff can approve a petition where there is no possibility the change to the facility will cause a significant environmental effect or where that change would otherwise be exempt from CEQA. Staff could also approve a change where the project would continue to comply with applicable LORS and there's no need to change any of the conditions of certification that appear in the Commission license.

There's one notable exception to that last bullet, that third bullet there. Staff can approve changes to air quality conditions of

certification in the license that do not increase daily, quarterly, annual or other emission limits.

So if the criteria that I just mentioned above can't be met, so like, for instance, there are needed changes to conditions of certification apart from what I just mentioned, the exception there, to ensure no significant environmental effects or LORS noncompliance, that would require Commission approval. That goes before the Commission at a noticed business meeting. If there's an objection to a Staff determination, you know, we believe that the change meets the criteria but a public entity does not and they submit an objection, they must do so within 14 days of Staff's filing and it must be supported by facts.

So for the -- so what we refer to as the non petitions, these are the things that may be more like in-kind replacement maintenance, those are typically authorized within one to two weeks.

I'm sorry. Next slide. I forgot to mention that. Thank you.

So those, the non petitions, can be authorized within one to two weeks of receipt to

the questionnaire. There may be some back and forth with the developer -- or the project owner, excuse me, to understand exactly the nature of the change.

Petitions, they can vary widely, as little as 30 days, upwards of 90 days. There have been some that have gone extensively beyond that but those have been for like almost wholesale changes to facilities that have been previously licensed. There's comment periods attached to each one of those petitions, you know, either Staff approved or Commission approved.

And I'd just like to say the SMUD Cosumnes AGP, that petition was filed on August 29th of 2018. Staff's analysis was filed on November 8th, 2018. That's, what, 71 days? And it was approved by the Commission on December 10th, 2018, so that did require changes to conditions of certification, so it went to the Commission for approval. And a total amount of time was 103 days.

MR. PITTARD: All right. Thank you. Thank you, Eric.

MR. KNIGHT: You're welcome.

MR. PITTARD: Much appreciated.

All right, our next panelist is Dawn Weisz from Marin Clean Energy.

MS. WEISZ: Great. Hi everyone. It's really a pleasure to be here. And I think I need someone on your side to turn on the video. There we go. There we go. All righty.

Thank you so much, Commissioners, for having this important workshop. First of all, we're really, really excited to be part of it. We've been thinking a lot about all of these issues. And I'm going to be coming at this from just a slightly different perspective than some of the other presenters as we're a load-serving entity and a buyer, so we're buying reliability products, resource adequacy. And I'll be speaking to kind of the challenges through that lens.

So we can go to the next slide.

And I'll just start off by saying that our board and our communities are really aligned with the SB 100 goals and getting us to a clean energy future as soon as possible.

I realize that this slide is very similar to one that Alex Morris presented earlier today,

so I won't spend a lot of time on it, but we are excited about the idea of battery storage hybridized with the gas fleet. And we are interested in it, you know, not just because it leads to a cleaner energy future but, you know, also as a retail supplier. One of our big priorities is protecting vulnerable communities. And so we're really excited about the opportunity that this technology presents for reducing air pollution, as well as carbon emissions.

So you can go to the next slide.

And I'll just make a comment here that I think that, you know, as we talked about technology advancements in the last panel, one of the challenges that I just wanted to highlight in this panel is that, you know, as we're expecting our gas fleet to do more ramping, you know, that can often cause more emissions in our vulnerable communities. And so, you know, that, combined with the local grid constraints that we see in places where large amounts of generation is needed, it kind of makes -- you know, it can make it hard to site new resources right where we need it. And, obviously, the, you know, the multiple cloudy day scenario or the extreme weather event

scenario is problematic, as well, for relying only on renewables.

So going on to the next slide, the, you know, addition of storage to existing gas plants is one solution that we have invested in. And so, you know, I wanted to point out that as -- you know, a role that we as a community choice aggregator can play is helping to invest in new technologies that increase or enhance reliability, you know, keep costs as reasonable as possible, and also help us move towards the state's decarbonization goals.

We entered into a long-term contract with a supplier for a ten-year resource adequacy product that is a hybrid gas-battery facility. And we are aware that, you know, adding these types of enhancements to a facility can be expensive. And so we -- because we believe in helping to make this transition happen the long-term contract really is what made the difference in allowing the counterparty to make the investments that were needed up front to transition the facility to cleaner operations.

You know, right away, from day one, you know, once the battery is fully operational,

we're going to see immediate air pollution reductions from nearby communities. And we'll start to see greenhouse gas reductions because there will be fewer starts. You know, when CAISO needs the supply from this facility the first place they'll be tapping is the battery. And in some cases the unit won't even need to ramp on and that will increase [sic] emissions by an estimated 60 percent from day one, so we're excited about that.

Let's move on to the next slide.

And I just wanted to, you know, add one other point to kind of address the end goal that I know we all share in phasing out carbon emissions in the long run. We're starting to look at ways now that we can begin investments in carbon-free resource adequacy. And you know, one way that we did this is we issued an RFP in February of this year for greenhouse gas-free RA. We got a number of proposals and some of them were, you know, tied to a transition where you've got, you know, a few years with the gas plant operating normally, but then it transitions to cleaner fuel sources and other technology improvements.

One technology that we've been really interested in, and we have a couple of potential pilot projects ready to get off the ground, include renewable hydrogen where hydrogen is being produced using electrolysis with renewable energy. And that can be stored for long periods of time and used in a fuel cell. So that could be a technology that helps us with the transition.

Also, you know, combining -- using hydrogen with our existing natural gas infrastructure, our pipes and facilities, is a really interesting opportunity. In our service area, which includes Contra Costa County along the northern waterfront, there are quite a few natural gas cogeneration facilities, many of which are currently not operating or just not operating fully. So we see some opportunities there to help make some investments and help transition those to cleaner fuel sources, whether it be hydrogen or biogas or other alternatives.

So that's how we're looking at the problem. And we're really excited to work with all of you to find some solutions.

MR. PITTARD: Great. Thank you, Dawn.

We appreciate you being here today.

Our final panelist for Panel 2 is Debi Le Vine from the California Independent System Operator.

Debi?

MS. LE VINE: Thanks so much, Shawn.

Good morning everyone. Let me see. Is my video working? Oh, there's -- okay.

MR. PITTARD: Yup, it is. We see you.

MS. LE VINE: Okay. Great. It's interesting, on my side, I don't see me. All I see is Shawn.

So good morning everyone. Thank you to the Commission and Staff for having this workshop.

Similar to Dawn, I'd like to go ahead and take the discussion to a different area and go over the events of this summer and the actions that the CAISO believes that we need to take and what we've already proposed.

Next slide please.

So as most of you know, August of 2020, we had the heat storm. There were power outages on August 14th and the 15th, predominantly due to the increased temperatures which were up to 20

degrees above normal. And in August we hit four out of five of the hottest days since 1985. The demands were high throughout the 24-hour period versus normally, in a heat event, you'll see that the demands decrease at night which allows the system to go ahead and catch up on the supply. But in this instance we didn't get that opportunity.

As a number of the panelists have already discussed, thermal generation operates less efficient in the heat. And because the event was west-wide, California has actually been a net importer since the 1960s, and because of the west-wide event the ability to import decreased during this storm.

We also had numerous fires, as other panelists have talked about, and the solar panels were not able to produce the energy required. And a number of the transmission lines which distribute the generation were impacted.

Next slide please.

So specifically, what ended up happening on August the 14th is at 1638 p.m. our reserves fell below the six percent NERC standard. And, in essence, that resulted in rotating outages for

492,000 customers. And the impact was between 15 minutes and 150 minutes, depending upon where you were on the grid.

And one of the interesting things is, having been in this industry for way too many years that I won't admit, the peak demand used to be around 1600, or 4 o'clock in the afternoon. What we're seeing is, is with the renewables, the net peak demand is much closer to the seven -- hour ending 7:00, which is between 6 and 7 o'clock at night. And because of that, we need different types of resources than we used to need, you know, five, ten years ago in order to meet that peak demand.

On August 15th the reserves fell below six percent at 6:28, just a little bit before the evening of the 14th, and those outages, luckily, only impacted for a period from 8 to 90 minutes, so we were able to bring that down.

Next slide please.

So the opportunities that we see is the CAISO put in place a number of emergency measures during the heat storm to allow operation of generating units above their pmax. It was all done manually by word of mouth, a lot of

communication. Thank you so much to the investor-owned utilities planning departments because for each one of the units that we allowed to go over their pmax, we needed to determine if the transmission system could support the additional generation because they'd never been studied at that level. So to allow each one of the units to go above their pmax, each one of those generators was studied by both the CAISO and the existing PTO that they're interconnected to. And then we'd have to go ahead and let the generator know that they've been approved.

In a number of instances the generators would have to take limiting schemes off of their generation. Some instances that was easy to do. Some instances they required a 24-hour notice in order to take off their limiting schemes. And all of this was done out of market, so there were huge challenges.

So some of the processes we need to put in place for this coming summer is to figure out which resources can operate above their pmax at critical hours? And as we've said, the max has actually switched and it's no longer four o'clock in the afternoon, it's closer to 7:00 p.m., 8:00

p.m. at night.

So the lessons that we've learned at this point is we need to be proactive in establishing, at least, the operation of a pmax.

As far as impact of proposed improvements, I really liked a lot of the discussion on both the Panel 1 this morning and some of the early speakers on Panel 2. We need to find additional ways to get more flexibility, whether it's adding batteries to gas units or improving the flexibility during the peak hours. That's what's going to help us get over the next couple of summers.

And we're also happy to help any of the units that are having trouble. Southern California noted in their presentation that there were spinning reserve clawbacks because of the way that the telemetry was set up on the battery versus the gas unit. We have gone ahead and worked through a number of those issues thanks to Edison being the first on the planet in California to go and deal with the combination of gas and storage. But we can help you through those types of dispatches and what information you need, et cetera.

We also want to improve the contingency planning with the CEC, CPUC and the Governor's Office, and continue to pursue market enhancements.

I'd also like to note that the CAISO did file comments in the OIR proposing, specifically for the summer of 2021, two items. One is to change the planning reserve margin for June through October from 15 percent to 20 percent. And also to go ahead and change, as we've discussed, the capability requirements to be for the hours ending 4:00 p.m. to 9:00 p.m. This goes ahead and allows us to secure imports, get more secured imports backed by firm transmission, access additional capability in the gas fleet, secure resources that are proposing to retire, and ensure storage resources are installed, charged, and ready to perform in critical hours.

And with that, I'll turn it back to Shawn. And I am interested in the questions that the audience has for us.

Thank you.

MR. PITTARD: Great. Thank you, Deb.

And thank you to all the panelists, both the Panel 2 and Panel 1.

I'll turn to the Commissioners now and ask if you have questions for any of the panelists that we've heard from, whether Panel 1 or Panel 2.

COMMISSIONER DOUGLAS: Hi Shawn. Hi Commissioner Scott. So I have a few questions. And oh, Commissioner McAllister, I didn't see you. I have a few questions. Maybe, yeah, several.

Now I understand the speaker from CESA had to leave; is that right? I was going to ask him something but we can follow up later.

I'll just ask a general question about the hybrid technology. I wasn't super clear from the presentations what the lead time is from conceptualizing, you know, a shift to a hybrid technology to putting it into effect. My assumption is that that's not a summer of 2021 activity unless it's already somewhere through the process or -- you know? But I'm not sure about that, so that's one question.

MR. PITTARD: Who can help us?

MR. SMUTNY-JONES: I'll give it a shot.

MR. PITTARD: Thank you, Jan.

MR. SMUTNY-JONES: Yeah. Jan Smutny-

Jones.

Commissioner, I think you're correct, and it has a large amount to do with whether or not, you know, batteries have been procured and the system has been planned accordingly.

I'll point out that there are a number of battery storage units coming on, some of them associated with something that repowers with natural gas fleet. For example, AES has something going on in Alameda. So there is some of this that's working its way into the system. Wellhead, again, one of our members was instrumental in working with Edison on some of this early.

So you know, I just want to underscore what some of the other speakers said on this. We view this as a significant opportunity as well.

COMMISSIONER DOUGLAS: Yeah, it certainly sounds like one.

And a just a quick follow up. I don't know, you know, for the hybridization strategy, is anybody that you're aware of looking at non-battery storage or is everyone pretty much, at this point, looking at battery storage with the power plants?

MR. SMUTNY-JONES: I wouldn't be surprised if somebody is looking at something other than batteries but I'm unaware of any specific project being both right now.

MS. LE VINE: So this is Deb --

MR. GOULD: This is Ross. I -- oh, sorry.

MS. LE VINE: This is Deb Le Vine with the ISO.

At the moment, actually, most people are looking at batteries. But as far as ease of putting them on the system, it's actually fairly easy. What we've allowed batteries to do is to go ahead and be added as a modification to an existing project instead of having to go through the entire study process.

COMMISSIONER DOUGLAS: Great. Okay.

MS. LE VINE: So that can be done in a 90-day period.

COMMISSIONER DOUGLAS: And Ross?

MR. GOULD: And this is Ross.

We actually have looked at thermal energy storage for a system where we have an evaporative cooler on the front end of a gas turbine where we, basically, pre-cool the water that goes into

the evaporative cooler to make it more efficient during the daytime. And it's a long-range project. It wouldn't be something you could pull together in six months but we are looking at it.

COMMISSIONER DOUGLAS: Oh, that's interesting. Well, I'd love to learn more about that sometime at some point.

I've just got a few more questions I'll tick through and then let others ask.

So there was some discussion of hydrogen. And just out of curiosity, maybe if Siemens is still on, or GE, I guess GE, you know, what's the maximum hydrogen blends that these engines, these power plants, can operate with?

MR. MINNIX: Yeah. This is Josh Minnix. I can speak to that.

For GE's aeroderivative turbine fleet it will depend on the product technology but, generically speaking, 35 percent is capable in the short range by volume of hydrogen. We've got a longer-term trajectory to bring those numbers up higher. On some of the other platforms, you know, on 2500, for example, we see a path to getting to 80 percent of total fuel; 20 percent of that would be non-combustible, so effectively

100 percent of the combustible fuel would be hydrogen.

It does require some modifications. There are some mechanical changes that need to be made to the turbine. But the combustion system itself tends not to be the limiting factor. It's more the availability of hydrogen and then getting the required blending skids and other supporting accessories installed.

COMMISSIONER DOUGLAS: Okay.

VICE CHAIR SCOTT: Commissioner Douglas, can I jump in right quick on that?

COMMISSIONER DOUGLAS: Yes. Please do.

VICE CHAIR SCOTT: I had a follow-up to that specific point (indiscernible) that there was a pathway to the 80 percent of more hydrogen. Is that something that you're seeing in the next year or two or is that something that's a 5-year, 10-year, 15-year kind of pathway?

MR. MINNIX: I think it would project specific. I would say that's more of the intermediate three- to five-year type of timeline for the higher percentages. The 35 percent would be achievable in a much shorter time period.

VICE CHAIR SCOTT: Got it. Okay.

MR. SALVATORE: This is Mike Salvatore from Siemens.

I'm going to go with what Joshua just said. That's the timetable we're looking at and moving towards that, so it seems to be an industry standard, if you will. And --

COMMISSIONER MCALLISTER: Can I jump in on that, actually, and just --

MR. SALVATORE: -- that's all.

COMMISSIONER MCALLISTER: Oh, sorry. Sorry to talk over you. I thought you were done.

I want to just ask about the hydrogen supply problem. Do you feel like the marketplace and/or policy is engaging with that sufficiently to kind of mobilize that overall hydrogen production conversation? I know this is not a 2021 summer discussion but the longer term sort of directionality of this is, I think, very important as well. Do you have ideas about whether we're taking appropriate steps to move that conversation about the hydrogen supply overall? Looks like not. Okay.

MR. PITTARD: No takers.

COMMISSIONER MCALLISTER: Okay. Great. It sounds like we have work to do to ensure some

hydrogen supply, so yeah.

COMMISSIONER DOUGLAS: I just had a couple more questions and then I'll -- I'm sure I'll probably hang off the other Commissioners' questions, as well, or I may.

You know, for the non battery, the non-hybrid solution, you know, I'm thinking through just time frames for Summer 2021 because, of course, we're interested in Summer 2021 for obvious reasons, and we're interested longer term for the obvious reasons. But for those subcategory projects that really could get going on that time frame, you know, I heard Calpine very clearly say, you know, they've assessed their facilities, they've identified which ones could potentially move forward on that time frame.

You know, I guess my question is, you know, what's the process for going through that kind of assessment? Is it something that's done that can be done quickly? Is it something that, you know, you need to be thinking about for months or years?

You know, I definitely heard from the first panel, it's better to fit this into, for

example, major maintenance so that you save costs, for example. And so there are obviously going to be some opportunities that come up that could be met on this time frame and others that just really don't make sense. And then we've got lead times to order and deliver equipment, and permitting, and the, you know, ongoing pandemic and challenges that that's put in place. So, you know, any insight on that would be helpful.

MS. MCBRIDE: And I can quickly answer that. This is Barbara McBride with Calpine.

I mean, the assessment probably took us a couple -- two to three -- or, you know, a month or two to go through. And, basically, what we did is took all our plants, looked at the technologies that were available and then, you know, obviously had to look at LGIA constraints and, you know, outages, when were the outages planned and, you know, and basically, you know, permitting a pathway, which, you know, you guys -- or the CEC and Air Districts have been very helpful with that, and then kind of went down and looked at it and said, look, you know, these work here, you know, these upgrades work here, these upgrades work over here.

And then we also had to have the discussion with, obviously, with the vendors, the OEMs, to see if the parts were available, especially for the combustion turbine upgrades.

And that's really the big deal now is we're ready. I mean, we're -- you know, as far as everything else, it's ready to go, except for, you know, we've got to make those procurement commitments but we can't do that without, obviously, you know, having some sort of pathway to get reimbursed for those upgrades.

COMMISSIONER DOUGLAS: Okay. So you've done that to the point of -- I'm sorry, just one quick follow-up. You've done that to the point of also ensuring that parts available? Like you feel like this is vetted?

MS. MCBRIDE: They're available. We just have to, you know, seal that deal; right? And we can't do that --

COMMISSIONER DOUGLAS: Yes. Sure.

MS. MCBRIDE: -- until we actually get the procurement piece.

COMMISSIONER DOUGLAS: Yeah. Got it.

MS. LE VINE: Yeah. The procurement piece is very important.

And the other area, I would say, that is untapped is we have a number of resources that have sent letters to the CEC, CPUC, and the ISO saying that they're going to retire because they have not been procured going forward for 2021-2022. And so there is a very easy, you know, amount of megawatts that are sitting out that, if they're procured, already exist, are already up and running. Their contract expires December 31st of this year, so they want to retire.

So the procurement piece and accessing the units that are looking at retirement I think is very critical and something that we can do easily to bring megawatts on for next year. Otherwise, we're going to lose them.

MR. SMUTNY-JONES: Just -- that's a very good point, Debi. And just as a follow-up on that, and Barbara's presentation, Commissioner, preparing of this, I have been calling around for my other gas members. People have internally done similar kinds of analysis that Barbara spoke of in Calpine.

So I think there are -- I think everybody's putting this into a range of possibilities with respect to what could actually

be done by 2021 or what could be done beyond, if need be. I think the key here is the procurement mechanism, people need to know that there's actually going to be an opportunity to, you know, build this into the market and have cost recovery of some kind.

And I recognize from a regulatory perspective the frustration here is that, you know, we're very short of time. You know, we're already at December 2nd. And I think as Barbara indicated, they have to -- they, Calpine has to make commitments to vendors with respect to equipment. Other generators are in a similar situation.

So the key there -- and I understand that there will be a panel later this afternoon to talk about some of these issues -- is how quickly we could get, yeah, we want you and, you know, here's the path forward with respect to 2021 and, you know, beyond if need be.

COMMISSIONER DOUGLAS: Um-hmm. I think those are my questions for now. I agree with you, the timing for Summer 2021 is the challenge. We heard from Air Districts that, you know, they'd like folks in the door yesterday for some

of these. And you know, there's also the equipment side. And there's just figuring out how this fits in with maintenance or other activities, so that makes sense.

Anyway, those are my questions for now.

MR. PITTARD: Great. Great. Thank you, Commissioner.

Other Commissioners, questions for the panelists? We're going to try to, at 11:35, take public comment. So other questions? We've got seven minutes.

VICE CHAIR SCOTT: I'll jump in. I had -- this question is actually not on the urgent timeline that we're talking about for 2021, which is staggeringly close right now, but it's thinking through.

The Energy Commission on the EPIC Program is getting ready to put together a bridge investment plan for the dollars. And I'm wondering if on some of these technologies where we're talking about a three- to five-year timeline, are there any research questions that the Energy Commission ought to be thinking about trying to help answer, either through our EPIC program -- right? --and so that has to be

associated with electricity, or through the Pure Natural Gas Program which could have, you know, hydrogen or some of these other conversations that we're having associated with it that we ought to be considering solicitations for now, obviously not for next summer, but research that helps us three years out, five years out, but we need to ask those questions now?

And that's a pretty broad question to throw out there, so maybe, I'm not expecting an answer, but just something I'm thinking about. And if it sparks an idea with any of you, to be sure to engage with us as we are doing that planning on the research.

MS. WEISZ: Yes.

VICE CHAIR SCOTT: Oh, I see Dawn may have an answer.

MS. WEISZ: Yeah. Well, I would just make a comment that I think we learned a lot when we did our clean RA RFO in February. You know, a lot of our responses indicated that there are suppliers out there. And I think, you know, it's good to kind of keep in mind that the CCAs and the IOUs are a part of the solution in that we can buy the energy that the CEC decides is needed

by the state. You know, we all want to do that. We all want to do our piece.

The responses that we got back on the RFO, many of them show, you know, there was a gap between where we are economically and, you know, what these new technologies need as far as an upfront investment.

So I think that you're right to be thinking about the EPIC Program as a potential way to bridge that gap. Because if there are -- you know, just like any new technology, if there's a way to make it affordable at the beginning until it kind of hits mass adoption, that can help with some of these things.

And you know, getting back Commissioner McAllister's question about, you know, what is the barrier to renewable hydrogen being, you know, adopted more full-scale, you know, from my perspective, it's cost. And so we're looking at doing baby steps, you know, some pilot projects, because they're going to be really expensive just to get the technology started and we can afford that if it's small. But with support from other entities, maybe through EPIC, bigger pilots could be done and bigger projects could be done to get

this technology to become more widely adopted.

COMMISSIONER DOUGLAS: So, Dawn, just because we have an extra two or three minutes, can you just tell us a little bit about the pilot projects that you're doing right now?

MS. WEISZ: Yeah. So we have two sites that are both in Contra Costa County that would be -- we would be locating an electrolyzer next to a wind or a solar facility. We actually are looking at a pilot of one of each, wind and solar. The electrolyzer would be right there on site generating hydrogen renewably. The hydrogen would stay on site. And there would be a fuel cell on site as well. When we need that energy, we would put it into the grid.

So that's the pilot. And we're looking at something that, you know, that's not tiny. We'd be looking at something between 10 and 15 megawatts ideally. And we're hoping to have something operational within the next couple of years. But we're still in the early stages of getting all the pieces put together but it's very promising. And there are, you know, companies out there, and you've heard from some of them today, who have a lot of experience in this area.

So the pieces are there. We just need to put them together.

COMMISSIONER DOUGLAS: Super. Thanks.

MR. PITTARD: All right. Other questions? We have two minutes worth of questions. Otherwise, we can -- we'll move to public comment.

I want to, again, thank the panelists for your participation. We learned a lot today. Much appreciated.

I'll hand this over to you, Noemi, for public comment.

MS. GALLARDO: Hello there. This is Noemi Gallardo, the Public Advisor.

Due to time constraints, today's speakers will not respond to questions asked during the public comment period. However, the comments and questions will be included as part of the record.

Commenters have up to three minutes to speak. We've got a clock here to help you look at what time you have left. And organizations are limited to having one representative speak on their behalf.

If you would like to make a comment in Zoom you're going to click on the raise-hand

icon. And then we will call on you so that you can -- open up your line so you can speak.

And for those on the phone you'll press star nine to raise your hand. And after we open your line we'll let you know and you can press star six to un-mute.

And when you are called upon, please make sure to spell your name, first and last, and state your affiliation, if any, for the record, then begin your comment.

And we do have a few folks already lined up here, so I'll call on you one by one.

First up is Grant McDaniel. He's been waiting patiently for a while now.

So, Grant, your line is open. You may speak.

MR. MCDANIEL: Yes. Thank you very much. I'm with Wellhead Power Solutions. And we've co-developed the hybrid technology with General Electric. We were involved with the installation of the Edison units. And we have just finished the 98 megawatts Stanton Hybrid Facility in Orange County. We're working with MCE to put in the additional hybrid here in 2021.

I want to address something that came up

with -- both in Josh's presentation, Matt brought this up, and I think Dawn brought this up, and it's really about the duration of the size of the battery. We understand that, initially, we were, in fact, optimizing on the smallest battery that we could use in order to get the, you know, the benefits that would make it economic. That's changed. And you know, as we move into this battery that we're going to be using on the facility upgrade that we're doing for MCE, it's going to be a much bigger battery size.

And it is going to allow us to have about a seven percent increase in power output but, also, address some of the concerns that Matt raised about, you know, getting dispatches where I might be at five megawatts or seven megawatts for 20 or 30 minutes. That will be accounted for. So the flexibility will also increase and so we believe that this will really help towards a further GHG reduction.

The other thing I wanted to bring up was that when we talked about hybrid the only thing that we really talked about waw in a single-stage gas generator or generator configuration. There are other configurations available. We could do

a multi-stage, meaning we can do a CCGT, in which case the primary thing that we're doing is increasing the ramp rate by two to three times by adding the battery. And what you're doing is just simply eliminating the steam turbine lag. And so you have that at its normal benefit to its day-to-day to help with the volatility with the grid. But then when the power is needed to be put out on top of the maximum, current maximum, it's available to actually increase power input.

And then the third one is really the non-generator. And again, with the battery we're looking at with MCE, through the hybridization project we're looking at with MCE, this is one where as we look to some very much-needed rule changes around hybridization that will take place next fall, we will move from a generator configuration to a non-generator configuration.

And this is extremely important because with the non-generator configuration it will allow the grid to use the hybrid as a battery and it will charge and discharge the battery. And it will only get to the gas when it is exhausted that battery. And that really gives us a much greater flexibility and a much more enhanced

product to the grid.

MS. GALLARDO: Thank you, Grant. This is Noemi Gallardo, the Public Advisor. Your time is up, so you wrapped up perfectly.

So next we have Michael Alcantar. I am opening your line now. And just a reminder to please spell you first and last names to make sure we get those correct on the record, and in case I butcher them.

All right, Michael, your line is open.

MR. ALCANTAR: Thank you. My name is Michael Alcantar, A-L-C-A-N-T-A-R. I represent the Western States Petroleum Association and a number of gas-fired, primarily, cogeneration facilities up and down the state but I wanted to make sure. And I may be preaching to the choir to several of the Commissioners' questions but there is a large disparity between what you need to do immediately to address issues and, more philosophically, what would be possible in the three- to five-year range is much different of what needs to be done immediately.

And this is really a credit to Debi Le Vine's, I think, most insightful comments about trying to bring us to reality about the

reliability problems that the ISO has already experienced and has no reason to expect that those won't be meaningfully repeated going forward in way that we all want to avoid and address. It demonstrates that our current planning, as much as we had hoped it would be something different, is certainly presenting a shortfall.

And so what I want to stress is the same point she stressed. There's an issue here of avoiding current losses by avoiding subtractions. It's addition by subtraction. And you have a number of projects, certainly three that I'm well aware of, who have additional dispatch for capacity available. They are CHP units that can provide and have provided reliability services during emergency conditions but they have no contracts going forward. And what that's telling those business enterprises is they have no future, and so notices start going out about terminating their resources.

Those resources are on the precipice of being gone. It makes no sense to fail to embrace those resources which are efficient, cost effective, from an emissions standpoint, some of

the best type of units you can have to address GHG issues, as well as reliability issues.

So I implore you to look at EPIC or whatever other programs you may have. I think there's some explanation from the CEC to explain their assessment of leaving CHP resources off their list of assumed solutions because of thermal obligations of host because that really doesn't compute to the reality and available of resources, capacity resources, reliability resources, from those projects.

Thank you for your time.

MS. GALLARDO: Thank you, Michael.

Next up we have Tim Buttke. And a reminder to, please, spell your name.

Tim, your line is open.

MR. BUTTKE: Okay. My name is Tim Buttke, B-U-T-T-K-E. I'm with Southport Equipment. And we represent SSS Clutch Company and they provide clutches for rotating equipment, including power plants.

I know the focus of today's discussion has been about improving generation capacity and reliability. But these same assets can also improve another important part of the equation

which is grid transmission reliability.

Obviously, when plants are running, they're generating megawatts. And when they're not running, which most peaker plants and other plants don't most of the time, they're really providing no benefit. But the generator can be disconnected from the turbine using the SSS clutch and then leave the generator providing grid stability with vars, spinning reserve, grid inertia, et cetera. And as we head to more renewables, these mega-vars are not being provided.

So synchronous condensing will become more important to the grid stability as we head towards 100 percent clean energy. And LADWP is already doing this at four of their plants in Southern California, successfully helping them to improve their reliability.

Other ISOs around the country have also provided compensation for synchronous condensing. And it is an asset that's available that I feel is being underutilized in California. So we're urging the agencies to come up with a market mechanism that synchronous condensing retrofits can be compensated and help improve stability for

California.

Thanks.

MS. GALLARDO: Thank you, Tim.

So next up we have Evelyn Loya. Again, reminder to please spell your name.

Evelyn, your line is open. Evelyn, your line is open. Please un-mute.

MS. LOYA: Can you hear me?

MS. GALLARDO: Thank you.

MS. LOYA: Okay.

MS. GALLARDO: Yes.

MS. LOYA: Hello. My name is E-V-E-L-Y-N, last name, L-O-Y-A. And I'm with SoCalGas Company. Okay. And Good morning.

MS. GALLARDO: Evelyn, we're -- Evelyn, sorry to interrupt you. We're having a little bit of an issue hearing you clearly. Make sure you're not on speaker phone.

MS. LOYA: I'm not. Can you hear me better now?

MS. GALLARDO: Okay. A little bit. Go ahead.

MS. LOYA: Okay. Good morning, Chair, President, CEC and CPUC Commissioners and Staff. Thank you very much for allowing me to make

comments on this very important topic.

As I reflected on the opening remarks by Commissioner Douglas, wide investments in natural gas power plants make to improve power efficiencies (indiscernible). While this may make since if we look at the power plants as isolated from the rest of the energy system landscape, this might not (indiscernible) even though the industries have the technologies to do so, as we've heard today. The natural gas capacity fleet reduction chart showed earlier does not (indiscernible) once-through (indiscernible) but also (indiscernible) unplanned retirement that are due to less usage. Many of these plants are less flexible plants but some are (indiscernible) combined cycle plants. The flexible (indiscernible) power plant are the backbone to system reliability.

Early on the CEC and CPUC noticed this inherent issue and held several workshops through the IEPR. About five years ago the CPUC was (indiscernible) capacity payments at the time but chose not to take this path. For those that are not familiar with capacity payments, these essentially are incentives for plants that are

underutilized and may not be able to afford to stay on additional payments to allow them to be ready for those few hours a year when demand is high and supply, mainly imports, are low. It is a low-cost and low-emission opportunity.

But I can come back to some scenarios in the Joint Agency Workgroup SB 100 which have non-combustion alternatives replaced by generic zero-emission (indiscernible) at $60.00 per megawatt hour. If it is the goal of the state to completely eradicate the gas system and gas power plants, and when energy agencies are stating they want to get rid of the plant in the next decade or so, why would any power plant put more investment into their infrastructure when they can barely meet their bottom line?

Thank you for your time.

MS. GALLARDO: Thank you, Evelyn.

All right, up next we have Brian Biering. Reminder to spell your name.

Brian, your line is open. Please un-mute and begin.

MR. BIERING: Hi. This I Brian Biering on behalf of Diamond Generating Corporation. My last name is spelled B, as in boy, -I-E-R-I-N-G.

Diamond Generating Corporation operates roughly 1,300 megawatts of peaking capacity in California in the CAISO that provides critical grid reliability insurance to the CAISO and other grid operators. We are actively evaluating various opportunities for capacity expansion, also closely looking at the carbon profile of our resources and looking at ways that we can decarbonize through renewable natural gas and adding storage. I would also point out that Diamond's parent corporation, Mitsubishi Corporation, is a global leader in hybrid technologies, and that's something we're looking at as well.

You know, given that the grid is already built around many of these resources, we really feel that they provide an opportunity to decarbonize the grid but really do so at a way that minimizes the ratepayer expenses that are, you know, inherently associated with meeting the SB 100 targets.

So we see these facilities as providing a critical transition opportunity into the SB 100 future. And to really do that, I think that the hurdles that we're seeing have been highlighted

by a number of the other speakers, and that's really in the procurement space. We really support, you know, Dawn and others' efforts to drive long-term contracts for new, you know, hybrid resources, you know, hydrogen use. But we really need to see more there to really make these investments and avoid some of those early economic retirement risks that have been identified by the Energy Commission and the CPUC in the past.

So really appreciate the opportunity to speak here and support the Commission's work in this important area.

Thank you.

MS. GALLARDO: Thank you, Brian.

So this is Noemi, the Public Advisor again. I see no more hands, so let me just give a reminder. If you do want to speak, this is your chance. You would hit the raise-hand icon. And if you're on the phone, you would press star nine. Okay, I'm seeing one more person.

So Miguel Sierra Aznar, your line is open. And a reminder to, please, spell your name.

MR. SIERRA AZNAR: Yes. Good morning

everyone. This is Miguel, M-I-G-U-E-L from Noble Thermodynamics. So we are a small startup spun out of UC Berkeley, actually working very much focused on zero-carbon dispatchable capacity, so kind of at the core of the conversation today.

The first thing we wanted to say is, obviously, thank you to the California Energy Commission for the continued support. We spun out of, actually, one of the grants. And we are very happy to see the bridge FOA (phonetic) coming out this year and, hopefully, continuing next year.

I think I will add to that, apart from, obviously, gratitude, raise the challenge that a startup like ours, developing new technology in this space, are facing around permitting. So as we try to deploy a demonstration project, or even run our own facilities, part of the support that I think California Energy Commission -- and I will add to this conversation, the Air Quality Management Districts -- is to speed up or streamline the permitting process for a startup or, actually, build a new mechanism, maybe in the sense of, maybe, temporary permits used for small businesses in trying to deploy units of these

characteristics.

We, as I said, are trying to deliver this zero-carbon dispatchable power. And we are doing that in Oakland. We, obviously, are facing the challenges of obtaining the permits to actually be able to provide that power. And that will be something that, I think, either CPUC, California Energy Commission, and Air Quality Management District can work together to streamline that for, as far as more companies have put innovation in California.

So with all that said, I just want to resonate to everyone else that support is much needed. I think natural gas, it's not so much natural gas being the enemy, it's just making sure that we have the right technologies out there to secure the future of California's electric grid, both in reliability, as much as affordability for the ratepayers. And that goes in line with not picking winners. I think innovation is (indiscernible) creativity. And for that, picking winners on those grants or those funding opportunities, I think is not beneficial. So I would say, please, continue to support technologies all across the spectrum.

Thank you so much.

MS. GALLARDO: Thank you, Miguel.

This is Noemi Gallardo, the Public Advisor again. I do not see any other raised hands.

I want to remind everybody that we also welcome written comments, which are due by 5:00 p.m. on December 16th. To submit written comments, please visit CEC e-filing Docket Number 20-SIT, that's S, as in Sam, -I, as in Ivan, -T, as in Tom, -01 or zero one. I should be clear about that. The links to the comment page for this docket. And the workshop notice provides detailed instructions on how to submit comments.

Jim, back to you.

MR. BARTRIDGE: Thanks Noemi.

And I just want to thank everyone, all our panelists and participants, for their comments this morning.

And let me just ask if the Commissioners have any closing remarks for our morning session.

COMMISSIONER DOUGLAS: Okay. This is Commissioner Douglas. I'm not in front of my camera at this moment but I just want to thank all of the panelists and public commenters.

You've given us a lot to think about and a lot of good information. And I definitely appreciate your participation and (indiscernible).

That's all I've got right now.

MR. BARTRIDGE: Thank you, Commissioner.

Any other Commissioners who would like to make closing remarks for this morning's session? Okay.

Hearing none, this concludes our morning session of the workshop, and we'll resume at 1:30 for session two where Panel 3 will discussion finance and governance opportunities. And we hope to see you all back here at 1:30. Thank you so much.

(Off the record at 11:53 p.m.)

(On the record at 1:30 p.m.)

COMMISSIONER DOUGLAS: All right. Well, good afternoon everybody, and welcome back to this afternoon's session of the Lead Commissioner Workshop on Incremental Improvements to the Natural Gas Power Plants for Electric System Reliability and Resiliency.

For those of you just joining, we've had a positive discussion today, and I encourage you to listen to the workshop recording that will be

posted after the meeting. Our morning session at two panels. The first included equipment manufacturers, storage advocates, and project owners and operators describing possible power plant improvements and their recent experiences with them. The second panel included Air Districts and the Energy Commission discussing permitting opportunities, and Marin Clean Energy and the California Independent System Operator highlighting process improvements.

The incremental improvement that existing natural gas power plants discussed this morning, including the additional battery and/or energy storage, can increase plant output, efficiency, turndown and flexibility, and provide insurance against the extreme weather, fire or climate-related events we experienced this summer.

This leads to the focus of our afternoon session, contracting for these incremental improvements and the services they can provide to help ensure a reliable electric system as we continue to implement our energy goal.

At this point I'll ask my colleagues, the Commissioners on this, participating in this workshop if they have any opening remarks they

would like to make?

All right, it looks like we do not, so I'll turn it over to the Public Advisor for some logistical information and instructions.

Thank you.

MS. GALLARDO: Thank you, Commissioner Douglas.

Good afternoon everyone. I'm Noemi Gallardo, the Energy Commission's Public Advisor.

This workshop is being recorded and being help remotely without a physical location consistent with Executive Orders N-25-20 and N-29-20, and the recommendations from the California Department of Public Health, to encourage physical distancing to slow the spread of COVID-19.

The public may participate and/or observe the meeting consistent with the direction in these executive orders. Instructions for remote participation can be found in the notice for this workshop. If you have any trouble with the Zoom online platform during the workshop, you can also call in at (669) 219-2599 or (877) 853-5257 and enter the morning session I.D. 937 8126 7870. This information is also being shown the deck

right now. The master deck of PowerPoint slides shown today have been posted. To find them, go to the Energy Commission's website at energy.ca.gov. And on the home page, scroll down to events, click on the link for this workshop and you'll find the related material there.

Because we care about you and the rest of our fellow Californians, we want to encourage everyone to stay safe surface the pandemic and take the following steps, wash your hands, wear a face mask, clean frequently, maintain at least six feet of distance from others, and visit covid19.ca.gov for more information.

Next slide.

Zoom is the Energy Commission's online platform of preference. I'll provide some quick instructions to improve your experience.

For those who can see this slide, we included images of the various icons you can use during the workshop. We suggest clicking on gallery view in the upper right corner of your screen to see all speakers simultaneously or, if you prefer, click speaker view to see one speaker at a time.

At the bottom of your screen you'll see a

black bar with an icon that looks like a high five which you can use during the public comment period to indicate you'd like to speak. For those who are panelists, you can use the icon that looks like a microphone to mute and un-mute when appropriate.

Please note that the chat and Q&A features are disabled for this workshop.

Next slide.

We will offer a period for public following the panelists' presentations. Due to time constraints, today's speakers will not respond to questions asked during the public comment period. But those questions and the comments will become part of the record.

Each person will have up to three minutes to speak. And organizations are limited to one representative. If you would like to make a comment in Zoom, click on the raise-hand icon and we'll open your line.

For those who have phoned in, you'd press star nine to raise your hand and star six to un-mute.

When you are called upon, please spell your first and last names. We want to make sure

we have a clear record. Also, state your affiliation, if any, and then begin your coms.

Alternatively and in addition, we welcome written comments which are due by 5:00 p.m. on December 16th. The meeting notice provides detailed instructions on how to submit comments. And you can also see that here on the screen.

With that, I'll turn it over to Jim.

MR. BARTRIDGE: Thanks Noemi.

I'd like to welcome Michele Kito with the Public Utilities Commission who will be leading our afternoon panel discussion. You can see we have listed our panelists today. As with this morning, we'll hold questions and discussion until after we've heard from the panel, at which point we'll turn first to Commissioners, followed by public comments.

And with that, I'll turn it over to Michele to get us started.

Michele?

MS. KITO: Hi. I'm Michele Kito. I work at the CPUC in the Energy Division in the Resource Adequacy and Procurement Oversight Section.

The way we're going to run the panel

today is I'm going to have some slides. And then we're going to have each of the panelists speak for a few minutes. We may then move to the questions before, I believe, taking additional questions from the dais, the virtual dais, from about 2:20.

So today I'm just going to be talking about some of the opportunities and challenges regarding the incremental capacity additions that were largely discussed this morning.

Next slide please.

So in broad overview, what I want to say today is that there are existing opportunities for procuring incremental capacity. And there are new opportunities that may arise with additional procurement requirements that may come from the Commission. I also want to note, however, that there are challenges with bringing these incremental capacity additions online by Summer 2021.

Next slide please.

So first, I just want to note that there are current authorizations that specifically address incremental gas additions. The CPUC's Integrated Resource Planning Decision, which is

D.19-11-016 did authorize procurement of up to an additional 3,300 megawatts of new resources to replace the once-through cooling facilities. That decision specifically allowed incremental additions at gas-fired facilities. And the language was,

> "If there are existing fossil-fueled resources that may have the ability to make modifications or produce incrementally more to serve reliability needs, those may still be considered, even if the units were not part of the baseline," that's just technical from the decision, "but only for the incremental capacity added.

So I would note that to date no load-serving entity has chosen to procure this type of incremental capacity to meet the identified IRP needs, at least as reported in filings to the CPUC. However, I would note that some folks have procured gas-fired resources and, in particular, Sutter was tied in as -- half of Sutter was tied in as a pseudo-tie, and some entities have procured capacity from Sutter.

Next slide please.

In addition, I would note that the CPUC

recently opened a new reliability OIR in response to the August heat storm events. The new OIR number is 20-11-003. And the purpose is to address summer reliability needs for the upcoming Summer 2021. The specific purpose is to either increase energy supply or decrease demand during the peak and the net-peak hours for the upcoming summer if needed.

But I just wanted to note that the OIR specifically asked this question, and this is relevant to the discussion here today, and the question is:

> "Should the Commission consider expedited procurement, including through the cost allocation mechanical, for additional reliability procurement, for example, expansions of existing gas-fired resources, that could be online for Summer 2021 or 2022. If so, how could this occur in order for the additional capacity to be online in time to address summer reliability needs?"

Next slide please.

I just also wanted to note that there are likely to be additional procurement requirements that will be upcoming to replace the closure of

Diablo Canyon. Diablo Canyon is a 2,000 megawatt nuclear power plant which will be going offline at the -- in two stages at the end of 2024 and, I believe, in August of 2025.

In the CPUC's IRP proceeding they have scoped the issue of the additional procurement that may be required to address the retirement of Diablo Canyon. The scoping ruling in that proceeding currently includes the following schedule. There's a Staff analysis of the individual IRP plans which is ongoing here in the fall.

There is expected, per the scoping ruling, a ruling regarding the replacement power and -- wait. There's going to be a ruling regarding the possible replacement and workshops scheduled in the scoping ruling for January 2021. In addition, comments and replies are expected to come in February and March. Finally, the proposed and the final decision would be in the April to May 2021 time frame.

Next slide please.

So I just wanted to -- I believe CEC Staff talked about this earlier, but I just want to talk a little bit about the resources that we

have online and that we used on August 14th, 2021.

So the green line is the renewables. And you can see that the renewables don't entirely go off in the morning and evening hours, and that's because we have geothermal and biomass assets that are base-loaded. In addition, we have wind assets that often produce during the evening. But the large bulk of it is solar and you can see that in this slide.

In addition, you can see the nuclear, which is the flat line at 2,000. You can also see the hydro, which is the blue line, which is has some ability to meet the net peak ramp needs.

Then I also want to note that the orange line is the gas-fired resources within California. And red is the imports. However, the imports, I just want to note, the imports include specified and unspecified imports, so those imports include Palo Verde and Hoover, as well as other resources coming from the north and south.

Okay. Next slide please.

I just wanted to talk a little bit about the emissions profiles. These are the emissions

profiles of the natural gas fleet, and also of the imports. So often folks -- I think folks believe that the imports are largely coming from the northwest and hydro. But they also do follow and appear to be in proportion to the gas fleet. So I went and looked.

This is a slide from CAISO and it shows a million tons of CO2 per hour. And I looked at our ending 19 in particular and the imports at that hour were 7,064. The GHG was 3,418. Likewise, the production from the natural gas fleet was 25,593. And the CO2 emissions were 12,307. So you can see that they're proportional to the -- well, actually, the emissions profile of the imports is similar to the emissions profile for the natural gas fleet. So it's not clear that they're necessarily hydro resources, so they look at lot like the natural gas fleet. That's the purpose of this slide.

Next slide please.

So I just want to note that there are both opportunities and challenges to bringing on additional incremental capacity for this summer. The Commission does have authorization and does allow incremental natural gas-fired additions to

meet the IRP requirements. In addition, we would imagine that there will be additional authorizations because of the retirement of the nuclear power plants, although that wouldn't be in time for this summer.

I would note that there are a number of challenges. There will be, likely, opposition from a variety of organizations. Some folks may believe that it's contrary to SB 350 goals. And there may be timing or cost issues. Some of the timing issues were discussed this morning.

In addition, I would note that it may also be contrary to the business models of some of the load-serving entities in California.

So that ends my slides. And so what we'll do now is we'll hear briefly from the panel members. They include Scott Ranzal from PG&E, also Valay-Paz from SDG&E, Mark Irwin from Edison, and Katie Ramsey from the Sierra Club. So I will invite Scott to say a few words.

I was hoping that you folks could first introduce themselves, maybe talk a little bit about your role in procurement, your organization's role in procurement, the load that your organization serves now and, potentially,

expects to serve in the future. And if you have any thoughts about what you've heard so far today, that would be fantastic.

Thank you.

MR. RANZAL: Quick sound check. Can you hear me?

MS. KITO: Yes, we can.

MR. RANZAL: Great. Thank you. Thank you for the opportunity to speak today. My name is Scott Ranzal. I am with Pacific Gas and Electric Company. My current role is the Director of Portfolio Management for our Wholesale Electric Portfolio.

Inside that role we have responsibility for the electric procurement responsibilities for all of Pacific Gas and Electric to unload procurement load. And we, obviously, work with an extensive fleet of UOG assets, as well as contracts to serve customers in Northern and Central California. PG&E currently serves approximately half of the load in Northern California, along with other load-serving entities in the PG&E TAC (phonetic) area and have continued to do so for quite some time.

As far as the discussion from this

morning, I thought it was a very positive discussion about opportunities that exist and the ability of the -- whether it be the PG&E fleet or the existing fleet inside the state of California, to expand and/or modify technology or process to gain some advantages and prepare for potential issues in the 2021 time frame and beyond. Obviously, the resources mix inside the state of California has changed dynamically over the past five-plus years and continues to do so. And that clearly is changing the profile and needs that exist from the systems.

So albeit we were able to get through the events of August, I think preparation, planning, and effort towards addressing that into the future, both near and far, are very positives steps. And I was definitely impressed with some of the comments and information that was provided this morning.

I know that inside of PG&E, we have been looking extensively at the fleet of assets that we manage in trying to identify, whether they be technology or process, where operating and performance improvements. We do so on a regular basis and certainly have continued that, even as

a result of the events that took place in August and September of 2020 and would, obviously, continue to do so. We would regularly analyze that fleet, understand what capabilities exist, and try to find opportunities that both increase performance and do so in at an appropriate cost-effective level so that it serves customers appropriately.

And we would continue to do that and have done that extensively, not only for the existing fleet but, also, for the procurement that exists out into the future that Michele talked about where PG&E has responsibility for a portion of the 3,300 megawatts that exist.

And with that, I will close and be ready to take any questions that might be out there.

Michele, let me know if I missed anything.

MS. KITO: Yeah. No, that's great. Maybe we could move next to Elsa?

MS. VALAY-PAZ: Hi. Good afternoon. Can you see me?

MS. KITO: Yes, we can.

MS. GALLARDO: Yes, we can.

MS. VALAY-PAZ: Okay. Perfect. Thank

you, Michele.

And thank you, Commissioners, for the opportunity of being here. I mean, what a timely conversation to have right now? I mean, we -- Michele talked about what's going on in the space in terms of the IRP Reliability RFO procurement, the electric reliability OIR, the heatwave that just happened in the summer.

And, well, first and foremost, talking a little bit about myself, I'm Elsa Valay. I'm the Director of Origination of Energy Supply and Dispatch. Really, what that means is that I have the benefit of being involved in several stages of our procurement efforts, so I'm involved in the origination side, launching the RFOs, but I also lead the team that really participates in the market every day at CAISO and bids our assets according to the least cost dispatch model, so I get to see like several faces of procurement. So I'm lucky to experience that every day.

At SDG&E, we're an innovative San Diego-based electric and gas utility. And we're really guided by our mission that is about improving the lives and communities by building the safest, cleanest, most reliable energy infrastructure

company in America. So reliability is very close to our heart. It's part of our mission state.

On average, we're proud to serve about 3,000 megawatts of load. And as we look ahead into the future, SDG&E is about to experience significant load departure. We anticipate that in the next decade it could be between 70 and 80 percent. And so, obviously, we're going through a lot of changes. And energy transition is at the heart of what we do.

Well, I would say, listening to the comments from our panelists in the morning, I think that SDG&E is very well aligned with what -- everything that was said. Reliability needs to be prioritized. The supply mix is changing with the increase of renewable penetration in our region. We also have a shift from centralized procurement that it was, basically, three IOUs in the state that were procuring to decentralize procurement. We talked about how the peak is changing and now it's more about the net peak, load peak, and that's shifting to 7:00 p.m. versus 4:00 p.m. So, obviously, a lot of changes and a very timely conversation to have, as I said before.

At SDG&E, we're -- I believe that when we look at reliability and we're trying to assess, you know, how to address the issues, we consider a multifaceted approach. There's not one silver bullet that will fix the issue. And I believe we need to prioritize reliability, affordability, and clean. I mean, all of those need to go together.

And, however, Michele said something that also really resonated with me. She talked about the opportunities, but she also talked about the challenges that we have ahead. And part of the challenges that we see at SDG&E are related to timing. So the electric reliability OIR that came out was asking questions about, like how can we meet the need, the reliability need, in 2021, and then in 2022?

So when we're thinking about those solutions, I believe that they're short-term based. The solutions are probably a little bit different; right? You probably need to look at what we were talking about this morning, like are there any improvements that we can implement in our gas fleet that are cost effective and that will be online on time? Can we implement

projects that can really maximize the interconnection capacity? Can we add chillers to our facilities that really allow our generators to perform at maximum level and not be subject to ambient de-rates? If we look at the preliminary root cause analysis, ambient de-rates really hurt supply during the heatwave storm.

So SDG&E, what are we doing? We're very focused on meeting the needs of the IRP Reliability RFO. I believe that, like it was stated this morning, we need regulatory certainty. And we, obviously, are seeking for expedited approval of those so we can move forward with the timelines and make sure that we have the resources available, our fair share of the 3,000 megawatts available by 2021.

In addition to that, thinking about 2022, and even 2021, there's resource enhancements that can be done. Some of those were talked about in the morning. I'm not going to elaborate more on them. But we're calling minor modifications that will really improve the reliability of service that our resources provide. We believe that we can do some of that work during the system plant maintenance outages.

And then looking ahead, you know, we need to consider expedited procurement. And SDG&E believes that there's an opportunity to take a look at even some of the resources that probably were not selected during a previous RFO and really maximize the time that we spend on that.

It looks like time is of the essence. And it really takes a long time to develop these resources. In the morning the developers talked and others talked about the time that it takes to really have resources online.

So those are some of the things that we're thinking of. Obviously, looking forward to questions and addressing any further comments that you have, Michele.

Thank you.

MS. KITO: Thanks Elsa.

Next up we'll have Katie Ramsey from the Sierra Club.

MS. RAMSEY: Hi. Can you all hear me?

MS. KITO: Yes, we can. Thanks.

MS. RAMSEY: Great. So hello and thank you very much for allowing me to participate on this panel today. I am a Staff Attorney for the Sierra Club. And I know that this slot on the

panel was reserved for a member of the Disadvantaged Communities Advisory Group. And while Sierra Club technically is not a member of that group, we work hand-in-hand with many of the members on that group, particularly with respect to issues related to gas plants and how they fit in with California's climate inequity requirements.

So I think everyone on this panel is probably aware that roughly half of the state's gas plants are located in disadvantaged communities. So when we talk about making new investments in the gas fleet there are very clear equity concerns. Most of these plants are already disproportionately affecting overburdened communities. And those same communities are pushing the state to reduce emissions from these gas plants. So any investments in these locations need to be scrutinized for how they will actually impact public health.

We've heard from the Air Quality Management Districts for the air basins that have been out of attainment for ozone and particulate matter for years. The state's peaker plants tend to operate on days when those ozone

concentrations are at their highest. So on the worst pollution days of the year some of these gas plants, particularly peakers, are making air quality worse at the worst possible time. So that air pollution has very real tangible effects on Californians.

The COVID pandemic has thrown all of this into very sharp relief (phonetic). We know that COVID risks increase significantly with increased exposure to air pollution. So when we're talking about the emissions from these plants, it has very real and direct impacts to our communities.

So I hope that the Commission is keeping those in mind when reviewing these investments and considering very carefully which investments will actually increase versus decrease emissions from those plants.

So in reviewing the proposals that were put out today, there are two main concerns that Sierra Club wants to highlight. The first concern is air quality. And the second is how well each of the proposed investments fit in with long-term planning and whether they're really cost effective in that longer time span lens?

So the first concern that I mentioned is

air quality. SB 350 requires the state to minimize air pollution with special priority for disadvantaged communities. And thank you, Michele, for flagging this in the challenges. You knew that I was going to talk about this at length.

So the current planning efforts for the Public Utilities Commission for 2030 include gigawatts of new renewable energy and storage. And the preferred system plan does not include any new gas capacity. So even under that ambitious plan with no new gas capacity the PUC has shown that the criteria pollutants are expected to increase under that 2030 plan for some of the most vulnerable communities in California, namely the South Coast Air Basin and the San Joaquin Air Basin.

So from a public health and equity perspective we need to be reducing air pollution above and beyond what we've already planned. So rather than tinkering with the efficiency of the gas plants the Commission should be asking itself whether those same amount of dollars invested in these projects might be better spent in alternatives that are completely independent of

the gas plants and also provide some reliability?

Are there any other options available that would actually decrease criteria pollutant emissions? If so, that's the direction that I would want to see the Commission taking.

So, for example, I know that So Cal Edison has highlighted decreased emissions from their battery hybridized gas plants. And we also heard that those projects were paired with new emissions controls. So one thing that I want the Commission to be considering in these new projects is are those emission controls required to meet those same kind of criteria pollutant reductions versus how many -- how much emissions reductions can we expect to see from these hybridized projects?

The second concern that I wanted to just touch on before we really dive in is whether these projects are really cost-effective investments that fit in with our long-term planning?

So as I mentioned earlier, the preferred system plants in the integrated resources planning proceeding at the PUC already doesn't include any new gas capacity. So the PUC will

probably update some of those forecasts to account for future heat emergencies, like we saw in August, but our climate mandate under SB 350 will stay the same. And we have the same target for climate neutrality by 2045.

So the state's load-serving entities are making these plans for these big investments in cleaner alternatives but there's ample room for regretful procurement if we're investing in fossil fuel resources. Any new investment needs to be scrutinized for how well it fits in and whether it's truly cost effective over the lifespan of those projects.

So for each of these projects the Commission should be asking how soon will these investments be paid off? Will the plants need to run more frequently in order to pay off these investments? Will these investments extend the life of gas plants beyond when their plant is useful?

Putting money into these investments need to be considered in the context of how long and how much we expect these gas plants to operate. If these investments are resulting in us increasing dispatch or increasing utilization of

those plants, it should be viewed very carefully with whether that fits in with our long-term goals.

So I want to see all of these proposals compared against other alternatives, including ways to reduce demand, ways to increase supply-side resources such as batteries or any other resources that could be producing during those net-load leaks, and that's the direction that -- that's the framework that I'm viewing these proposals and that I hope the Commission and other stakeholders are keeping in mind viewing these proposals as well. So those are my ideas and that's the framework that I'll be viewing the rest of these proposals with.

Thanks.

MS. KITO: Thank you, Katie.

Next we'll have Mark Irwin from Southern California Edison.

MR. IRWIN: Okay. Thank you, Michele. Hopefully you can hear me.

MS. KITO: Yes.

MR. IRWIN: Okay. Great. Thank you very much for allowing me to speak today. Both thank you to the Commissioners and the Staff. I really

appreciate the opportunity.

My name is Mark Irwin. I'm a Director of Energy Contract Management at Southern California Edison, so my team manages all of our existing contracts which is where these type of proposals would generally come from in our organization. And we would manage the evaluation and negotiation of any modifications to the contracts coming forward.

I really, really appreciated the comments made this morning, and they're very consistent with my recent experience in talking to projects about these type of changes and modifications. We've talked about some of the key issues which is how fast it has to happen. The Air Quality Districts, I think, are saying it needs to already be started which, I think, is consistent with what we're hearing from counterparties. The procurement side, we heard from Calpine talk about, again, it needs to start within the next 30 days. So I think those are both things that we've seen and experienced.

And then the other piece that I think is on the table to talk about is what does cost recovery look like? One of the big challenges

we've seen in some of our conversations with people has been around the current term of their contract and whether they can really cost effectively price an upgrade under the current term of a contract that may only have, you know, somewhere in the one to three to five years remaining? So that becomes a cost competitiveness issue.

So we've seen a lot of this. We've actively managed our portfolio now for, you know, quite a number of years, and so we are familiar with the resources. I appreciate all the comments around, you know, what the system needs going forward. And I think it is important to ensure that what we're doing is consistent with those system needs. The plants we have seen coming forward with these are plants that are still in the, you know, well under 20 years into their lifecycle, so they are what I would consider the more model plants in the fleet. We've not seen really much in the way of proposals from some of the aging plants so far.

So I think as I -- the other -- oh, sorry.

One other thing Michele wanted us to

answer, which I think really goes into our question -- into our thinking here, is what's our load look like? What do we serve? And what do we expect to serve in the future?

So today, you know, we serve, as I recall, in the 70-odd percent of the customers in our TAC area, that's expected to decline. And we've seen some more action that might accelerate the decline from what our most recent forecasts have been. So we do expect to see that decline, which also informs us in how long we're willing to go on our position which is, you know, some of these comments before about, you know, somebody may need another three, five, seven years on their contract to be able to pay it out at a reasonable price. And with that, you know, declining load profile that we're going to serve, that becomes a much greater risk.

We also will be acting as the central procurement entity for all local in our area. And many, many of these plants are in local areas because that's what they were procured to do to start with was to serve a local need. So there's also the tension between whether the central procurement entity should be considering these as

it gets established next year or not?

So lots of, I'd say, complications but, I think, nothing that makes things impossible, just puts things in a position where we have to make a judgment on the most cost-competitive thing to do for customers. And if we have -- as we have concerns over doing longer-term transactions, we'd want to put that in front of, you know, the appropriate regulatory process. The question becomes is, is there time? And I think that really goes to the root of 2021 is, you know, what is there time for? What is there not time for? What is cost effective? What isn't cost effective within these kind of frameworks and structures that we've got.

So it's a very, very interesting challenge. And I'm happy to engage in the conversation about how we're thinking about it.

MS. KITO: Thanks Mark.

I just wanted to follow up with one question that was discussed this morning. Edison had put on -- had hybridized some of it -- or one of its peakers. And I just, I believe it was a ten megawatt, four megawatt hour upgrade. And I just want to clarify that really helps with

flexibility but it wasn't really much incremental capacity; is that right? It's only, really, one megawatt?

MR. IRWIN: I'm not sure there was any incremental capacity, Michele. If there was it was minor. The five peakers that we have, if we hybridized any of them, there would be -- the design was really no incremental capacity, it was about fast response. And we actually completed two of the five.

MS. KITO: Okay. Thanks. I just wanted to clarify that --

MR. IRWIN: Yeah.

MS. KITO: -- I mean, there was tremendous interest in the hybridization. And it does help with the flexibility in emissions. But I just wanted to clarify in terms of summer reliability, it may not get incremental capacity to hybridize those assets?

MR. IRWIN: That's correct. Yeah.

MS. KITO: Okay. Thanks.

And then I just want to talk a little bit about whether your organizations are considering these for your bundled service customers, and whether the IOUs would be willing to consider

these upgrades as a CAM (phonetic), sort of a CAM upgrade on behalf of all load-serving entities, and if you have any thoughts about that, any of you?

MR. IRWIN: Well, this is Mark. I can take a shot at that first.

So most of the projects that we are looking at this are currently CAM contracts. As I said, they were bought for local reliability. We have been willing to look at them as CAM resources because they are CAM resources. And it would be probably quite a bit of a challenge to try to break a piece of the resource part. As we look at extensions beyond, if we were in a situation where we had to do an extension, substantial extension, then I think we'd still consider them as CAM resources.

You know, Edison has taken the position to date, and as I talked about with our central procurement entity activity that we are going to be taking on, I think that we view the buying resources for the system when the system has requirements in our serving territory and for overall state reliability has been something we've been, you know, willing to do our share,

and our share being kind of our TAC area share.

MS. KITO: Okay. Thank you.

Elsa?

MS. VALAY-PAZ: Yeah, Michele, I think that's a great question. As we were analyzing the different options to kind of like meet reliability, like in 2021 and 2022, some of these upgrades are definitely focused on what we're calling our Local Reliability Portfolio. So I think, for us, having CAM as a cost-recovery vehicle for those seem appropriate. It's also, you know, we already have a methodology for passthrough of the costs and all that. So we believe that that's, you know, that would be the right approach for those.

MS. KITO: Okay. So -- and maybe, Scott, you want to address this. I would note that the Calpine fleet that they indicated this morning that was able to add incremental capacity, that was Delta, Pastoria, and Metcalf, they have numerous offtakers. And do any of you have thoughts about how one could, I mean, should it be cost effective, how one would contract for it given that there are so many offtakers on that?

MR. IRWIN: So, Michele, it's Mark. I

can comment if you'd like?

Or, Scott, you can go ahead?

MR. RANZAL: Go ahead, Mark. I can follow.

MR. IRWIN: Oh. Okay. So when there's multiple offtakers, what that generally is an RA, a series RA agreements. And so what we've found is, if that's the structure, you know, extending -- these type of upgrades have, generally, two types, two elements, ones an efficiency element and ones an RA, a capacity uplift. The capacity uplift is pretty straightforward to sell through another RA agreement.

And what we've seen some parties look for is, you know, certainty of their entire capacity beyond the term. So they're looking to sell a lot of RA in some of the out years and a little bit of RA in some of the inner years. And that's certainly a complexity that we've seen that, you know, to get a little bit in the near term you've got to buy a lot in the long term.

MR. RANZAL: Yeah, Michele, I would agree with Mark's comments. In large part what we have seen is that there is a capacity component to it

that really extends beyond the existing, you know, regulatory framework and, as a result, contracting out for that longer period of time that the generators need in order to get the payback on the investment that they're making. It creates a challenge to identifying an appropriate way to cost effectively manage the increased capacity and functionality that would become available on the system.

MS. KITO: Okay. So I guess what I'm hearing is that all the IOUs are considering these types of upgrades for resources that they already have under contract of under CAM contract? But for the resources that have multiple offtakers, that it's considerably more complex to figure out the way to contract for them going forward?

MR. RANZAL: Michele, this is --

MS. VALAY-PAZ: I can --

MR. RANZAL: -- Scott.

Oh, sorry. Go ahead, Elsa.

MS. VALAY-PAZ: Oh. Sorry. One thing that I --

MR. RANZAL: No.

MS. VALAY-PAZ: -- wanted to say, you

know, I think it depends because some of these resources might be in a different TAC area. I think that there's mechanisms in place that generators have to have multiple contracts for one resource; right?

And I think when, at least for SDG&E, when we're thinking about CAM and cost-recovery treatment related to enhancements, those are resources that we currently have in our portfolio, so we are the offtaker for that. But, for example, if there was a resource available it the PG&E area and SDG&E is has efficient system RA and that is available and we are able to participate in an RFO or whatever and, you know, contract capacity, I think that there's vehicles to do that.

So probably I would kind of like -- it's almost like a two-prong approach. If it's a resource that's part of our local reliability portfolio, I think that some of the -- some, if not all, of these enhancements could be part of the CAM cost-recovery mechanism. It's already in place. But if it's about contracting a resource that is in another area, I think, particularly as it is system reliability, other LSEs, not only

the LSEs in that area, should have access to them.

MS. RAMSEY: I wanted to chime in really quickly on the idea of CAM, using the CAM mechanical to spread these costs. And the first is that California does have an established loading order requirement that energy efficiency and demand response resources be tapped first. And so there should be some caution here before requiring all these purchases to be made that there is real effort expended in trying to find out whether demand response options would be more cost effective.

So I realize a lot of this conversation is focused on the technical, on whether we can do this, whether it's possible to get it done by next year, but the Commission should also be keeping in mind that there is still a should question. Like should we be doing all of these investments or should we be looking at alternatives first or in addition? So I would put that out as a caution to make sure that the Commission is really considering demand alternatives first before jumping to buy all of these new projects.

MS. KITO: Hey, Kate, this is Michele. I agree with you. And I think the OIR did talk about demand and supply-side options. However, I would note that in the heat storm over the summer, some of the demands and options were firing up diesels to reduce demand at hospitals.

So there is a question of whether -- I mean, I think we all want to be prepared for next summer. And I absolutely agree that one has to consider both options. But we also do want to ensure the reliability of the system. And we want to respect all the SB 350 goals, as well as the loading order. But thanks for your comments.

MS. VALAY-PAZ: Michele, can I add something on that demand response side, just very quickly?

On the SDG&E side -- and you're right, in the electric -- in the reliability OIR there was an opportunity to chime in on demand response side, so I want to clarify, we're not ignoring that. Actually, SDG&E submitted an advice letter with a plan for demand response resources.

And a lot of the issues that we see in our area is we don't have CNI participation, and probably because the incentives are not there,

and that's what we're working on. We believe that we need to provide the right incentives so customers participate when we have a system reliability event.

I think it goes back to the challenges that Michele was talking about in the beginning -- right? -- the timing of it. And we need to ensure the reliability is there. We're obviously, again, we're looking at a multifaceted approach, focusing on CAM because there were some of the questions that were around CAM. And I think that there is a benefit as long as we're able to prioritize reliability, affordability, and clean energy; right? I think those three things are needed. And some of these projects that we're looking at are probably going to move the needle on reliability and are also going to reduce emissions, which is pretty much aligned with some of the conversations that we had today, so I just wanted to add that.

MS. KITO: Thanks. So I think we've answered some of the questions about whether you're considering these types of additions. And I think some of you are. I think we've also touched on whether they're cost effective. I

assume that you guys are -- Elsa has talked about considering demand-side and supply-side options. I think we're talked about impediments to development. There are issues of cost allocation, load migration.

Maybe we could talk about the timing. So to the extent that you are undertaking or considering any of these, are you encountering any permitting challenges or other issues if you're considering these options?

MS. VALAY-PAZ: I can start, Michele. I think some of the challenges that we have is until we have regulatory certainty, at least for -- and I'm thinking about the IRP Reliability RFO, you know, the investment dollars that project developers are willing to put in, you know, they're small, so they need that certainty. And you know, condition precedents are regular recourses that we add to contracted to give certainty and comfort to developers; right? I think that that's a big challenge.

The other thing, too, is, you know, COVID. We are living in a very uncertain time. And there's going to be supply chain disruptions. That's why we're so focused on the regulatory

timeline. And you know, it will be hard to assess if COVID is going to like further disrupt the value chain. It's something that we're looking at and, obviously, very focused on.

That's why I believe that if I can call it like low-hanging fruit, other than the Reliability RFO and expedited approval on those, some of these enhancements could help us -- right? -- meet the needs in the summer. But it's hard to say like, you know, what are the issues that are going to be ahead? But time is of the essence.

MS. KITO: Okay.

MR. RANZAL: And Michele --

MS. KITO: It looks like we --

MR. RANZAL: -- this --

MS. KITO: Oh, go ahead. Yeah.

MR. RANZAL: This is --

MS. KITO: We only have a couple more minutes --

MR. RANZAL: -- this is --

MS. KITO: -- but go ahead.

MR. RANZAL: Absolutely, I would echo onto what Elsa was saying. You heard it this morning that, certainly, COVID has an impact on

the way outages are getting managed and the ability to do that. It has also impacted the processes in order to get decisions about cost recovery and working through projects.

So I think it's been successful to date but it is certainly slower than it is normally, even though folks are still working very hard to try to do this. And in the shortened time frame we're looking at here, you know, to try to really address what happens for summer of 2021, that window is, unfortunately, closing day -- getting closer and closer to being closed day by day.

And you know, the recent increases in COVID are, also, not particularly helpful. Pulling resources from other parts of the country, which is normal practice, has been more difficult to address outage activity and actually get some of these things built and put in place.

So even if you are considering some of them and you can get through permitting, operationally achieving them and affording the outage windows associated with doing some of this work are also still hurdles to be crossed, and there's a lot of checks to be marked on the list in order to get the successful conclusions for

the system.

MS. KITO: Okay. Thanks everyone.

It's 2:20, so I think I'm going to turn it back over to Jim to manage questions.

MR. BARTRIDGE: Great. Thank you, Michele.

And I'll just ask -- just turn it to Commissioners and see if they have any follow-up questions.

Commissioner Douglas, would you like to start? Commissioner, you're on mute.

MS. GALLARDO: Commissioner Douglas, you're muted.

COMMISSIONER DOUGLAS: All right. There we go. I double muted myself, I was being extra careful, and I only un-muted one.

So anyway, I want to thank all of the panelists. And this is a really interesting discussion.

I wanted to say, Katie, you know, thank you for participating. And I know that you're not on the DAC but we very much welcome the perspective that you bring, and appreciate your participation, and appreciate the questions that you're asking.

We are, of course, at the Energy Commission and the Public Utilities Commission and across the state, working very hard to meet our SB 100 goals. And that's the overall umbrella that we're working within. And we're also, as has been noted, working very hard to make sure that we have in place what we need for Summer 2021 and for transitioning our system beyond that. And there's a wide suite of tools that we can help bring to bear to do that.

And you know, when I first came on the Commission, of course, we talked about the loading order quite a lot. And that concept is still very much there. You know, as we move forward and we think about what does it take to meet our reliability challenges, you know, of course we're thinking about efficiency and we're thinking about new clean generation and batteries and all sorts of opportunities. And as you kind of go down that list you hope that you don't get to the diesel backup generators and the most impactful options. And you certainly hope that you don't get back to blackouts.

And so we -- you know, I certainly feel as though we need to look at all options here as

we work to transition our system in a logical way. But we also, obviously, we do have to look hard at the cost and the tradeoff and where does the investment of scarce resources go? And what makes sense and what doesn't? And what's achievable and what isn't? And so that they're -- you asked a lot of good questions.

I think I guess my general question, you know, I've heard a lot of really interesting ideas today. Some seem, potentially, plausible for helping us Summer or late Fall 2021. Some seem longer term and maybe more amenable to having, you know, a broader or more -- you know, thinking about it without the time crunch that we're under with anything we would think about for, really, Summer 2021.

But just to ask the panel generally, you know, what are some of the ideas and what are some of the processes that seem most ready to you, that seem to make the most sense in terms of the economic tradeoff, in terms of the achievability, in terms of maybe, you know, being able to make a case pretty easily that a plant is not going to increase its emissions, you know, maybe be able to even decrease them? You know,

what does the panel see as some of the ideas that (indiscernible) to maybe make a short list, so to speak?

MS. RAMSEY: I can go ahead and take this one, if nobody else wants to jump in?

MS. KITO: Sure.

MS. RAMSEY: Okay. So I know that we talked a little bit about the peaker battery hybridization. That seems, possibly, to have some opportunities to decrease emissions. Like I mentioned earlier, I still have questions about whether the decreased emissions that SCE was able to realize were due to their new emissions control equipment versus batteries and, you know, which -- where the response really -- or where the credit for that goes? So that's one thing that I think is easier for nearby communities to be willing to accept than something that purely just increases capacity without providing any local benefits.

But at the same time what a lot of the communities that I've worked with are asking for are investments in cleaner alternatives to reduce those emissions altogether. So at the forefront where my clients and our membership are

interested in, they're looking for decreased emissions, something that will improve the air quality.

And then the other thing beyond that is making sure that it's cost effective over the lifespan of those improvements. If these improvements are meant to improve emissions for the next five years but that gas plant may or may not be needed beyond the 2026 or 2030 or 2045 deadlines, keeping that lifespan in mind is very important to make sure that you're paying off those investments before those plants are decreasing their output further. And so that's a question that, I think, is important to ask in reviewing each of these proposals. And I think that some of those proposals fare better than others.

COMMISSIONER DOUGLAS: Yeah. That makes sense. And it's kind of an interesting balance that, I'll say we but I think a lot of this goes to rest at the PUC, and I know they work hard on these questions. It's like, one hand, you don't want the plants to leave while you still them need and on the other hand, you don't want to pay for them beyond when you expect to need them.

And so I think, you know, obviously, they do a lot of hard work and through -- with stakeholders, as well, to try to address that.

But I see a couple other panelists here. Go ahead.

MS. VALAY-PAZ: Yeah. I just wanted to chime in very quickly.

I think the challenges and the tension that, I believe, Katie is referring to goes back to what's the problem that we're trying to solve; right? If it's the 2021 problem, then I think it sends you down a path. I mean, yes, part of it will be addressed with IRP Reliability RFO.

Michele talked about how none of the LSEs have presented thus for, you know, expansion in gas-fired generation. I mean, there was a different focus. And I think part of it is because people are not just procuring for 2021; right? We're procuring for the long term. We're procuring for the 2045, the 2030 goals, or whatever.

So I think that we're pretty much aligned on that. I think if we're trying to fix the reliability, then it's where, you know, the wheels over here start spinning and we start

trying to think about creative ideas that contribute and really move the needle in system reliability effectively, cost effectively. We're not going to be, you know, reckless and just like procure because we need to procure. There's all these different provisions that we have in place. And, obviously, we have a Commission that is very focused on that, ensuring that, for example, from the utility perspective, that we're procuring based on the least cost/best fit, which is a priority of us.

So I believe that practically speaking, I think short term for us is 2021 and 2022. Thinking about enhancements of current gas-fired generation that's going to improve reliability, that's going to reduce some of these ambient de-rates, like the chillers, that is going to allow us to maximize that interconnection capacity that we have. We don't need further permits. If there's interconnection capacity that we're not able to maximize, that's one thing.

And then, second, if we really need to have expedited procurement the challenge with that, and I know this firsthand, running an RFO takes time. And then on top of that, getting

approval takes time as well. So I think, ultimately, that's where SDG&E, we came to the table with, hey, can we leverage some of the due diligence that we did in the IRP Reliability RFO where we had identified resources that were not viable per the timeline of the IRP Relationship RFO but that could definitely help meet the needs in 2021 and 2022 and still like being mindful of all these different things that we're talking about in terms of reliability, clean, and affordability?

MR. IRWIN: Yeah. I just wanted to echo those comments. I think Elsa has got it exactly right which is if we're trying to solve '21, you know, we've had some conversations recently, you know, battery suppliers have no batteries for '21. Even if you could find a developer that could develop a project fast enough, which is also extremely problematic now, there's no battery supply. There is some supply in '22. There are some projects capable of getting to '22. But '21 in the battery space is close to nonexistent. You can never say nonexistent but you can say awfully close to nonexistent. And in the gas space, there's a little bit of wiggle

room but not much.

And the good news, I think, from my perspective is the places we have seen the opportunities in the gas plants are, again, as I said before, some of the newer plants that we wouldn't expect. We'd expect them to be among the last gas plants to retire.

VICE CHAIR SCOTT: I have a follow-up question for -- this is Vice Chair Scott. I'm not sure where I am in your Hollywood Squares. I had a follow-up question for Elsa, actually, on the RFOs. And maybe if Mark or Scott or Katie wants to weigh in, as well, I'd be happy to hear that.

One of the questions that I have is if you could give us a little bit more detail about the RFOs that you're talking about? And I have -- I kind of have two questions with that.

One is, and I'm kind of likening it to the solicitations that we do at the Energy Commission sometimes where you might have ten projects that are amazing, they pass the score, they meet everything we want them to do, but we only have funding for five. And if we get extra funding, you could kind of go down the list, and

those other projects also meet everything that we were looking for in the first place. So it's not as hard to kind of go back and brush that off to pick those versus they have different qualifications, different requirements. And so now you can't really use that list because it doesn't match what you're looking for.

So I guess it's kind of a two-pronged question; right? Is it a list that these are what we're looking for and you can kind of just go right down it? Or is it a list that doesn't quite meet what we're looking for and we would need to add some tweaks or some other things to be able to brush it off and use it in the way that you're describing?

MS. VALAY-PAZ: Yeah. Thank you for your question. The RFO that I'm specifically talking about is actually -- was launched in the IRP proceeding, so it's very targeted on addressing the reliability, so the IRP Reliability RFO online date, 2021, 2022, 2023.

So to your point, the fit of that RFO, with what we're looking for, to meet the gap of -- you know, like to avoid any issues, like in the summer, it's like a very good fit, very well

aligned. And I believe that when I say that there might be an opportunity to go back, you could have -- we could have had a really good resource that met the criteria, you check all the boxes. Unfortunately, that particular resource was not a good fit for, let's say, 2021 for that particular RFO, but maybe it is a good fit for the summer reliability event.

I'll say that some of the challenges that we experienced with some of our -- it's ongoing, so I want to be careful in terms of what I share, but it was about like you have a very good project. Unfortunately, you know, the viability, it's not there because of are they going to achieve full deliverability status from CAISO? Is that a resource that you're going to be able to claim for resource adequacy?

So, hopefully, that addresses your question.

MR. IRWIN: Yeah. And just a follow-up on that. So we ran our -- our reliability RFO, we have the second leg of it almost complete, which is our '22-23 projects. For our '21 projects, we signed contracts in the spring. They were submitted to the Commission. We already have

Commission approval. The projects that could have done '21 are no longer able to because the time has gone too long. We could have brought more for '21 at the time.

MR. RANZAL: Yeah. And I would echo similar comments. The solicitations that were out there did have a targeted aspect of them. And I would have to get that most of the folks are, you know, continuing to have discussions with folks. And if there is an opportunity that it addresses something else, we're certainly not ignoring that opportunity. But for the RFO that exists, you know, it doesn't necessarily fit there.

So I think you can go back to the list and say, if there is another need where it could be met, there, potentially, is an opportunity for discussion. We're not ignoring that but it doesn't necessarily happen in the RFO.

And one further comment on Commissioner Douglas's earlier point, I think it was clearly expressed this morning in this morning's panels, the things that are already on the runway, you know, and are moving forward and have made progress are some of the things that are really

going to help address what's happening for the summer of '21/22. So they've gone through vetting, due diligence. They have made steps forward. You know, were they planning to come online in November of 2021 or January or February of 2022 or whatever reason, you know? Is there a discussion opportunity there to say is there a chance for you to move that forward?

Because a lot of the work has already been done, that acceleration effort, I think, is another area that a lot of people are looking at and having an open discussion and dialogue to try to address, you know, this is already a good project that meets a lot of the requirements that's, ideally, addressing the needs that are addressed in the SB 100 or SB 350 in any way, shape or form, and are vetted through our normal process, great. So I have a lot of those checks already.

Now the one question is: Could we do it a little bit earlier or for, you know, to Elsa's point, for a larger size? That would help an immediate need that sits in 2021 without diverting your long-term plan, which is really how a lot of us -- almost like how we think about

a lot of our planning activities; right? This is certainly not, I think we're all aware, this is certainly not an exercise of going onto Amazon and picking what you want and it comes to your house another day. It would be fantastic if it did work that way but it does not.

And we're all aware of the, you know, the activities that are required in order for us to put these things in place. This is long-term infrastructure planning and it does take time. So when events like this happen we can accelerate but there is a throttle to that that can only be turned up or down so much, I guess, is a way to say.

COMMISSIONER DOUGLAS: So I just wanted to ask a follow-up on that point.

When it comes to acceleration, you know, you know, we've certainly talked about that and looked at it. And I was just wondering, are there, you know, are there suggestions you have for how the state can be helpful, how the Energy Commission can be helpful as you work to get those projects that are already in the pipeline, as you mentioned, on the ground as soon as possible? I mean, I know that a lot of this is

just about, you know, things that we really have very little control over. You know, when you go on Amazon and add something to your cart, I know you just said that's not what you do, but you know --

MR. RANZAL: Right.

COMMISSIONER DOUGLAS: -- I was just -- yeah. Any suggestions you have?

MR. RANZAL: I would actually argue that I think the Commission and the ISO and the CPUC (phonetic), to the extent necessary, have been helpful thus far.

COMMISSIONER DOUGLAS: Um-hmm.

MR. RANZAL: You know, if we're engaging in conversations and there's things that need to happen, I think we're opening up dialogue, and they've been receptive to it. And there's clearly an understanding of the need from the combined CEC, ISO, and CPUC regulators that the summer of 2021 creates a concern, so I think that they are trying to be as helpful as possible.

In terms of modifying existing process, I'm not sure that I have a recommendation there that says, well, if we did this it would cut it. I don't have that at the tip of my tongue. But I

have seen a lot of assistance and proactive, very open-minded, if we thought about it differently, would that work in allowing us the opportunity to ask those questions, have an open dialogue with the regulators, and the developers where necessary, to potentially come to conclusions that are positive for the system?

COMMISSIONER DOUGLAS: That's great. I'm glad --

MR. RANZAL: I'd be willing to do that.

COMMISSIONER DOUGLAS: -- to hear that. I know that's the intent but it's good to hear that that's manifesting.

MR. BARTRIDGE: Commissioner Randolph, would you like to ask any questions, or Chair Hochschild?

COMMISSIONER RANDOLPH: I'm trying to think of questions that don't get into market issues or into process issues, so I think I'm just going to consume now for a while. I have been fairly knee deep in all of this. And so I really appreciate you all taking the time and giving us some of the practical realities. And I'm also pleased to hear that the lines of communication are open with Staff of the various

entities so that we can do a lot of problem solving.

So we have a lot of activity that we anticipate coming in the Reliability OIR, and in IRP, and in RA. So I am extremely optimistic that we can unpack some of these challenges and make it work.

MR. BARTRIDGE: Great.

Chair Hochschild, did you have a comment? Okay.

Karen, with that -- Commissioner Douglas, excuse me, I think we're right at about the time. It's 2:39. We are going to move to public comment if you have no other questions or otherwise?

I just want to thank the --

COMMISSIONER DOUGLAS: I have no other questions. Thank you. I don't see any other Commissioners jumping to make any closing comments but they -- okay.

VICE CHAIR SCOTT: Yeah. Just a thank you to the panelists --

COMMISSIONER DOUGLAS: Yeah.

VICE CHAIR SCOTT: -- for an excellent day.

COMMISSIONER DOUGLAS: Thanks.

MR. BARTRIDGE: Very good. And I echo my thanks as well. We've had a great discussion all day.

And let me just turn it over to Noemi and let's go through some public comment.

MS. GALLARDO: Thanks Jim.

So hello again everybody. This is Noemi Gallardo, the Energy Commission's Public Advisor. Due to time constraints today's speakers will not respond to questions asked during the public comment period. But the questions and comments will become part of the record. Commenters will have up to three minutes to speak. And organizations are limited to having one representative speak on their behalf.

If you would like to make a comment, in Zoom, click on the raise-hand icon. For those on the phone, press star nine to raise your hand. After we open your line, press star six to un-mute. When you are called upon, please spell your first and last name and state your affiliation, if any, for the record, then begin your comment.

So we do have a couple of hands raised so

far. First will be Andy Brown.

And, Andy, I remind you to please spell your first and last name. Your line is open, Andy. Feel free to un-mute and begin.

MR. BROWN: Hi. It's Andy Brown, A-N-D-Y B-R-O-W-N. I'm with Ellison, Schneider, Harris & Donlan. We help a number of folks, including LSEs, and also generators. And one of the -- I'm mostly just making a couple of observations, not on behalf of any specific client at this point.

We heard this morning that, sort of in response to the extensive heatwave event that happened across the west that robbed a bunch of capacity that otherwise would typically be available to California, that the ISO is suggesting that the planning reserve margin be increased across the summer, some of those high-demand months. And at the same time we're also talking about what could happen with existing gas resources that may be both towards the tail end of their economic life but, also, running out of existing contract.

And what I guess I'm foreseeing here is an actual increase of scarcity of capacity if there isn't a good runway for re-contracting and

improving these assets, including things like converting some of the existing sites to these hybrid configurations that may provide an existing brownfield site that can still inject energy and provide capacity with storage at very low emission levels but have the existing and, perhaps, enhanced gas resource there that can provide longer-run capacity. Because a lot of our resources that we rely on day in and day out become unavailable during periods of high pressure and high temperature that sits on the state for a long period of time.

And so it becomes a question of what we are trying to solve for. And one of those questions is: Do we -- would we prefer to not see emissions potentially occur and have blackouts instead of do you have the resources around, try to minimize the emissions by lowering the amount of run hours, but have them available to operate should, you know, these heat events, which I think are expected to increase over time, occur more often.

And then the last point I'll try to make is, you know, really, for resources that are coming off contact, I need to know the path for

re-contracting years ahead before the contracts going to run out. Otherwise, the likelihood of premature retirement or just the capacity not being available to the system is high.

Thank you.

MS. GALLARDO: Thank you, Andy.

And now we'll have Michael Alcantar.

And, Michael, please re-spell your name so that we have an accurate record. Your line is now open. Please un-mute and begin.

MR. ALCANTAR: Thank you. Michael Alcantar, A-L-C-A-N-T-A-R, on behalf of WSPA.

I just, I realize you're not going to take questions this way, but it seems to me that an implicit assumption in the comments made by Mark Irwin and in the other procurement representatives, it is very much focused on what are we going to do to enhance over the three and five and longer term periods of these resources?

But what still strikes me is the most emergent issue, and I think this is what Andy Brown just said, in part, addressing is you have a large number of existing capacity resources, existing efficient resources that are moving to situations without contracts. Those facilities

will depart. They will retire prematurely. The result of that premature loss is additive to the problem we're trying to solve, near-term (indiscernible) and longer-term (indiscernible).

I hope the path that the state wishes to (indiscernible) than to worry about the five-year contract that somebody wants because they want to -- or seven-year or ten-year contract that a (indiscernible) wants because they want to look at retrofit upgrades versus simply looking at a facility that's saying, I have major maintenance scheduled, payment periods that are five years in duration, and I'm not asking for the moon. I'm asking just to continue to exist on my existing contract with an extension that can be done expeditiously and properly before you lose that resource and you're starting over again. And I know Mark Irwin is intimately familiar with the number of projects in that category.

So thank you.

MS. GALLARDO: Thank you, Michael.

I do not see any other raised hands, so let me folks another chance. So if you're on the phone, press star nine to raise your hand. If you're on the online platform, please click on

the raise-hand feature. And we'll give it a few seconds, just in case people are shy and trying to work up the courage to raise their hand. Okay, it doesn't like anyone's raising their hand now.

So I also remind folks that we welcome written comments which are due by 5:00 p.m. on December 16th. And to submit written comments visit CEC's e-filing Docket Number 20-SIT-01 which links to the comment page for this docket. On this slide we included links to where you can visit to file comments electronically and where to click to view all documents filed in this docket. The workshop notice provides detailed instructions on how to submit comments. I have also put into the chat the information for you to go to the link where you can file comments.

And with that, I'll turn it back to Jim.

MR. BARTRIDGE: Thanks Noemi.

Again, I just want to thank everyone for a great workshop today, our panelists in the afternoon, especially, bringing it all home for us. I think there's a lot of opportunity to continue these conversations going forward.

And I also thank everybody for their

patience with me over the last couple of weeks, and all of the emails, especially over the holiday week.

So with that, I'll just turn it back to Commissioner Douglas and ask if she or any of the other Commissioners would like to provide some closing remarks? And, if not, we can close up the workshop.

Thank you.

COMMISSIONER DOUGLAS: Hi. This is Commissioner Douglas. No closing remarks for me.

Again, I want to thank all the participants here today.

MR. BARTRIDGE: Very good.

Any other Commissioners for final comments?

VICE CHAIR SCOTT: Nothing additional, other than our thanks. This is Vice Chair Scott.

COMMISSIONER RANDOLPH: This is Commissioner Randolph. Same here.

MR. BARTRIDGE: Very good. Okay. Well, thank you everyone. I think we've had a great workshop day, and a lot of good information out here, and look forward to continuing these conversations moving forward. So, again, thanks

for your time and attention and look forward to working with you as we move forward to deal with the reliability issues for 2021.

Thanks so much.

(The workshop concluded at 2:49 a.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 18th day of December, 2020.

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, CERT**367

December 18, 2020