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BEFORE THE

CALIFORNIA ENERGY COMMISSION

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Report (2017 IEPR)	)	

JOINT AGENCY IEPR WORKSHOP ON RISK OF

ECONOMIC RETIREMENT FOR CALIFORNIA POWER PLANTS

CALIFORNIA ENERGY COMMISSION

FIRST FLOOR, ART ROSENFELD HEARING ROOM

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, APRIL 24, 2017

10:00 A.M.

Reported By:
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Ross Gould, Sacramento Municipal Utility District (SMUD

Also Present

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INDEX

	Page
Introduction	
Heather Raitt, IEPR Program Manager	5
Opening Comments	
Chair Robert B. Weisenmiller, California Energy Commission	6
Commissioner Janea Scott, California Energy Commission	11
Commissioner Liane M. Randolph, California Public Utilities Commission	
Tom Doughty, Vice President, Customer and State Affairs, California Independent System Operator	9
Rachel Peterson, Chief of Staff to Liane Randolph, California Public Utilities Commission	10
Background: Joint Agency Roles	
Sylvia Bender, CEC	11
Michele Kito, CPUC	14
Neil Millar, California ISO	37
Greg Cook, California ISO	51
Panel Discussion: Potential Solutions	65
Melissa Jones, Moderator	
Greg Blue, Cogentrix	66
Mark Smith, Calpine	71
Brian Theaker, NRG Energy	75
Paul Cummins, Wellhead	78
Eric Little, Southern California Edison (SCE)	81
Vic Kruger, San Diego Gas & Electric (SDG&E)	87
Joe Lawlor and Jim Gill, Pacific Gas & Electric (PG&E)	88
Ross Gould, Sacramento Municipal Utility District (SMUD)	92
Public Comments	149
Closing Remarks	153
Adjournment	157
Reporter’s Certificate	158
Transcriber’s Certificate	159

P R O C E E D I N G S

APRIL 24, 2017 10:00 A.M.

MS. RAITT: All right, shall we go ahead and get started? Okay. Good morning, everybody. We're going to go ahead and get started, so if you could please take your seats.

Good morning and welcome to today's Joint Agency IEPR Workshop on the Risk of Economic Retirement for California Power Plants.

I'm Heather Raitt, the Program Manager for the IEPR. I'll quickly go over housekeeping items.

If there's an emergency, please follow staff to Roosevelt Park, which is diagonal to the Energy Commission.

Today's workshop is being broadcast through our WebEx conferencing system and so parties should be aware you're being recorded. We'll post an audio recording in about a week and a written transcript in about a month.

At the end of the day, there will be an opportunity for public comments, and we will limit comments to three minutes per person.

For those in the room, who'd like to make a comment, at the end of the day just fill out a blue card and you can give it to me. And for WebEx participants, you can raise your hand and let our coordinator know you'd like to make comments at the end.

Materials for the meeting are at the entrance and posted on our website.

Written comments are welcome and due on May 8th.

And with that, I will turn it over to the Chair. Thank you.

CHAIR WEISENMILLER: Thank you. I'd like to thank everyone for being here today, particularly reaching out to both my fellow agencies and, of course, Commissioner Scott.

But anyway, I think this is a good time to have this meeting today. What we want to look at is basically the -- let's see, I'm not sure it's the risk of retirement but, basically, what's coming up in terms of retirements on our power system.

I think, generally, people understand that our reserve margins are high, from either a planning or operational basis. But location and characteristics really matter. It would be as if someone was looking for a three-bedroom apartment in Los Angeles, and we said, well, we have lots of one-bedroom in Sacramento, what's the problem. You know, location is really important on the grid stuff.

And, obviously, one of the things the ISO does is help on the locational stuff. But you really need both -- you need plants with the right characteristics, in the right location.

You know, having said that, again, as we do the transition to fewer plants, one of the things that's going to be important is to try to make sure that the ones we need to stick around stick around, and the ones we need to be gone are gone.

You know, I remember when we had the -- FERC had the capacity market hearing, workshop in Sacramento. At that point, we and they were assured that the PUC and the utilities could use the bilateral contract system to keep the flexible, new, efficient plants around, and at the same time get rid of the less efficient, older plants. And, so, part of this is the reality check on where do we stand?

Obviously, this is an interesting year to have the conversation. We've switched from drought to high hydro, so that I think last year we had probably about 10,000 gigawatt hours of hydro, at last in Northern California. Who knows if we get to 40 or 50,000 this year. Which means that we're going to have lots of periods of renewable curtailment, of lots of negative price periods.

And that, certainly, again, looking forward, as we add more and more renewables, the result is going to be that wholesale power market prices are going to go down. Which anyone who has generating assets is going to see their revenue decrease, unless they can figure out ways of maximizing the value.

Remember a couple of years ago, I was told by Bonneville that they had seen their revenues drop by 20 or 30 million that year, which they were attributing to, basically, the lower wholesale power market prices. So, obviously, one of the things Bonneville is really doing at this point is trying to figure out how to enhance the value of their generation, by trying to get it into higher value periods, and to get into providing more services.

So, I think part of their message is that we're certainly starting a new day. You know, I expect to see more and more retirements, frankly. But that's the good news, in a way, and we just have to make sure that we have stuff remaining in the right locations, and with the right operational characteristics. You know, we certainly want to keep very efficient, very flexible units in the right locations. And others it's not obviously why are you still around?

So, anyway, thanks everyone for being here.

Tom?

VICE PRESIDENT DOUGHTY: Well, Chair, thank you.

And to my fellow dais members, thank you.

Chair, you covered most of the topics that I wanted to touch on. But I wanted to make note of something that occurred just this weekend. And those of us who follow our app, or our website, probably know this.

We hit, on the ISO grid, our lowest ever net load number this weekend, about 9,165 megawatts. What does that mean? What's the context of that? Well, remember when we released the duck curve four years ago, we thought in 2020 that we'd get down to about 12,000 megawatts. Here we are, now, in 2017 at 9,100 megawatts.

So, you can picture this duck getting thicker and thicker, as more and more renewables are added to the system.

And as you mentioned, Chair, prices are low or negative across very wide spreads of our day, now. Units with marginal costs, that are higher than zero are dropping back out of that market, and they are being put into a position of revenue insufficiency.

Now, the ISO has had a series of meetings with generators, who've approached us, representing these challenging circumstances. And what's been missing for us is a durable, structured process for engaging in these conversations, for prioritizing, for analyzing in a consistent way.

Neil Millar, of our shop, does a tremendous job, and his team, analyzing each of these plants that comes to the door with these challenges. What we need, now, is a process that makes this more of a predictable and durable exercise.

So, we're here, today, to offer our views on the challenges that these economic retirements represent and, of course, to learn from people in the audience of how we might do this better. So, thank you, again.

MS. PETERSON: Thanks Chair, and thanks Tom, and Commissioner. My name is Rachel Peterson. I'm not Commissioner Randolph. I'm her Chief of Staff. And she has -- the Commissioners are holding a closed session this morning, so she apologies, but she will be here shortly after 11:00, I believe. It was kind of an unstoppable force and an immovable object. We couldn't have her be in two places at the same time.

And, so, I won't make very many substantive remarks because I know she'll be asking questions and learning throughout the day, too.

But just to say that our office is assigned the resource adequacy proceeding, the long-term integrated resource planning proceeding, as well as a number of transmission projects. And, so, through those proceedings we certainly learn from probably some of the same representatives about the reliability and the risk of retirement situation in California.

I think it's great that this workshop is happening with all three agencies present, because it is our three agencies that really have to work together to try to ensure liability for California. And we just look forward to the day, to learning and discussing. Thank you.

COMMISSIONER SCOTT: Good morning. I just want to say thank you so much to our colleagues from our sister agencies for being here this morning. And thanks to everyone who will be participating in the workshop. It's a great opportunity for me to listen and learn, so I'm glad to be here.

MS. RAITT: Great. So, this morning we start off with presentations on joint agency roles. And, first, is Sylvia Bender from the Energy Commission.

MS. BENDER: Good morning, Chair Weisenmiller, Rachel for Commissioner Randolph, Commissioner Peterson and Vice President Doughty.

I'm Sylvia Bender, the Deputy Director of the Energy Assessments Division here, at the Energy Commission.

This joint agency workshop is one of two workshops that will be exploring electricity system reliability issues, as California further reduces its greenhouse gas emissions by integrating greater amounts of renewable, variable resources.

On May 11th, we'll have another joint workshop on the operational aspects that will address the increasing need for flexibility on both the supply and demand sides, and potential options to address peak shifts and growing ramping needs. Such as demand response, time of use retail rates, storage, and expanded western energy imbalance market, or regional grid, and new ways of using excess renewable generation.

Today, our topic is the risk of retirement, for economic reasons, by gas-fired, hydro, wind, cogeneration, and geothermal resources, or what economists might call a missing money problem.

This has several potential consequences. In the short run, the viability of existing facilities needed to keep the grid stable is threatened as renewables put downward pressure on wholesale prices.

In the longer run, it may preclude investments in the types of resources that can provide the flexibility attributes required for reliable service.

Our agenda for today beings with presentations by Michele Kito, from the Public Utilities Commission, followed by Greg Cook and Neil Millar, of the California Independent System Operator. Each will discuss recent work by their agencies on these issues.

Following this, this afternoon, a panel of generation owners, and utilities will provide their perspectives in a moderated discussion focused on four topics. The issues facing different types of generation resources at risk of retirement. Local reliability needs. How to value the changing generation attributes and performance needed? And possible market or regulatory approaches and solutions.

As California’s electricity system evolves, resources that can be depended upon to quickly and cost effectively ramp up or down, or provide other grid services to help maintain system and local reliability become more valuable.

Flexibility is needed to compensate for hourly changes in variable renewable generation and demand, as well as seasonal variations in hydro power.

Given the evolving environmental regulation and increasing amounts of renewable generation capacity, the Energy Commission anticipates that older, less-efficient power plants will continue to retire as they find it increasingly difficult to recover their costs. And that the Commission will need to identify and plan for any upcoming retirements.

Similarly, the Energy Commission will identify any local regions of the grid that may require preservation of existing generation or other electrical service needed to maintain overall system reliability.

Today's workshop discussion, and your written comments, will contribute to informing our subsequent Energy Commission analyses, and eventual policy recommendations that will appear in the 2017 Integrated Energy Policy Report.

So, I will turn it over, now, to Michele Kito.

MS. KITO: Hi, everyone. My name is Michele Kito and I'm a Supervisor of Resource Adequacy and Procurement Oversight. And today I'm going to cover four major topics.

The first thing is I want to talk about the CPUC's current forward procurement requirements, which is RA program. Then, I'm going to talk a little bit about early economic retirement. Then, I want to talk about forward procurement and the uncertainties and challenges associated with it. The, finally, I want to end talking a little bit about the tradeoffs between reliability, costs, and I also want to talk about the changing structure of the grid.

So, the CPUC's Resource Adequacy Program, as many of you know, developed in response to the 2001 energy crisis. The initial program was implemented in 2006 and those were system requirements. Local requirements were added in 2007. And I'll talk about these in future slides. The flexible capacity requirements were added in 2015.

The purpose of the RA program is to ensure that we have, the CPUC jurisdictional load serving entities, LSEs, have sufficient capacity to meet the peak load, usually that's an August peak load, with 15 percent planning reserve margin. It's also to ensure that we have resources in local areas for reliability. And, finally, that we have flexible ramping resources associated with renewable integration. As you all know, it's a one-year forward requirement, or many of you know.

So, this is just a map, a little bit out of date, of CPUC jurisdictional LSEs, and CAISO. So, the yellow is the CAISO area. The other areas are non-CAISO areas. The CPUC jurisdictional LSEs compose about 90 percent of the load in CAISO. There are currently 26 load-serving entities that we regulate. There are three investor-owned utilities. There are eight community choice aggregators. And there are 15 electric service providers.

So, the purpose of this slide is just to show you the growth in CCAs. This is based on the 2014 year ahead load forecast. And also, then, based on the 2017 August revised load forecast that we get from the CEC.

So, you can see in 2014, IOUs were serving about 90 percent of the CPUC jurisdictional load. The ESPs were about 10 percent, and the CCAs at that point in time were less than 1 percent.

Fast forward to 2017. IOUs now represent about 85 percent of the load. ESPs are still around 9 or 10 percent, but you can see the growth in CCAs. So, for this coming August, as of right now it's about 6 percent.

So, this is just a quick overview of the resource adequacy requirements. There's a system and this is based on a monthly forecast of a 1-in-2 weather year, with a 15 percent planning reserve margin. The local requirements are determined annually by CAISO, and they're adopted by the CPUC. And these are based on a 1-in-10 weather year, as well as a N minus 1 minus 1, which we'll go over in the next couple of slides.

Finally, the flexible capacity requirement is also based on a CAISO study and it's determined monthly. And it's based on the largest three-hour net load ramp, with some additional adders.

So, I think that this is a helpful graph to give you a sense of the system requirements and also to show you the kinds of resources that are under contract for the CPUC's RA program. This isn't the entire RA program, but just that are regulated by the CPUC.

So, the very bottom line we aggregated a number of resources. So, this is biomass, geothermal, hydro, import, nuclear and CHP. We combined a lot of these for confidentiality reasons. We have, usually, a rule of three. So, if there's only one person having nuclear, we don't like to show that.

So, anyway, you can see the yellow. The orange is natural gas in the RA fleet. And you can see that this is pretty much the largest component of the RA system. The red is demand response. Wind is the blue. And at the top is solar.

A couple of important points to note is that for RA system resource purposes, we don't use very much solar in the winter, and that's because of the way we determine the MQC, which is based on assessment hours. So, the assessment hours in the winter are later in the day, so the MQC is very much lower.

And wind is also based on those assessment hours, and those are usually during the day. Wind is often producing during the night. So, this is the RA fleet for 2016.

So, just to talk a little bit about the local capacity requirements. This is based on an annual LCR study. It's based -- as I said before, it's a 1-in-10 weather year. And it's also an N minus 1 minus 1 contingency. So, imagine a very hot day, and imagine two very large things going wrong. The loss of two transmission lines. So, what you want are resources in the local areas to serve load under those circumstances.

This study is adopted annually by the CPUC. So, you can see that there are ten local areas. For the CPUC's purposes, we only -- we aggregate into five areas. So, we have Bay Area, other PG&E areas, L.A. Basin, Big Creek, Ventura, and San Diego. That should be San Diego IV.

So, why do we have five areas, if there are ten local areas? So, in PG&E's service territory, six of the local areas are combined into PG&E other areas to address market power concerns. So, those six areas that are combined are Sierra, Fresno, Humboldt, North Coast, Stockton, and Kern local areas.

This is just a note about how we allocate the local requirements. It's based on load share ratios, August load ratio shares. It is not based on where the

LSE has load. So, you would still have a Bay Area requirement if you're in the PG&E TACK area, even if you weren't serving load in the Bay Area.

So, I just wanted to show the 2017 local capacity requirements. I think this is a really helpful chart. On the top we have the total LCR for each of the ten areas. We also have the 1-in-10 peak load. You can see you have LCR has a percentage of peak load. You also have dependable area, dependable capacity in the area. And, then, you have LCR as a percent of the total area resources.

So, you can see in some areas the requirement is almost all of the resources. You can see Stockton and Sierra, for example. I'm sure the CAISO will talk about this, but not only are there -- for CPUC purposes, we only require that resources are shown in the local area, but there are also sub-area restrictions that it would be better if they were met.

Okay. So the last column is also important because it gives you an indication of the resources that are able to meet the LCR needs in those areas.

Okay. So, turning to the flexible requirements. These are the 2017 flexible requirements. I won't go into the buckets. But the point being here that the flexible needs are greater in the winter, in the spring, and not so great in the summer. And we'll go into that a little bit on the next page.

So, these are net ramps by season. So, the top one is -- net load ramps -- the top one is the summer. And you can see, at least in this picture, it's kind of a gentle slope. So, the net load ramp is not as steep. But, alternatively, if you look down at the bottom, that's April 14th, you can see that the net load ramp is a little bit steeper.

So, in the summer you need more overall resources, but possibly less flexible resources. Alternatively, in the spring you might need fewer overall resources, but more flexible resources.

So, we just bring up this point to say that the needs differ by season. They aren't uniform all year round.

I also wanted to show this slide. This is about the net load ramp drivers. And the point that I wanted to make here is it's not always solar PV that's contributing to the net load ramp. So, if you look at January and December, for example, the contribution of load is about 50 percent of the net load ramp. And the contribution of solar PV, with the behind-the-meter, at least in January, is about 50 percent. And in December it's a little over 50 percent.

Alternatively, if you look at the spring, you can see that the solar PV production is really driving the net load ramp. So you can see in May, load is contributing about 24 percent. Solar, in front of the meter and behind the meter is contributing about 75 percent.

So, putting all those requirements together, I'm going to show a couple of graphs. So, these are the 2016 RA requirements for CPUC jurisdictional LSEs. The first bar is load, it's the load forecast that we get from the CEC. It's a monthly forecast. The red bar is the CPUC requirements. So, you can see that incorporates a 15 percent planning reserve margin. The green bar is the local requirements. And the local is a year-round requirement, so it's the same all year round. The purpose are the flexible requirements. And, again, you can see that they're larger in the winter and spring and much smaller in the summer.

We also just wanted to note, at least for CPUC jurisdictional LSEs, we bundle these products. So, if we have the flexible attribute, we also have to count the system attribute. Likewise, if we have the local attribute, we also count it toward system. So, these are not additive, they are subsets of the system requirement.

So, these are the 2017 requirements. You can see the load forecast has gone down somewhat. So, the August peak requirement here is 47,587. Again, the first one is the load forecast. The second one includes the planning reserve margin. The third is the local, year-round requirement. And, fourth, the purple is the flexible requirements. They've increased, you can see, but still the seasonal pattern stays about the same.

So, every year we do an RA price report. Sometimes we're early, sometimes we're late. This year, we're going to try to be early. So, this is some of the preliminary data that we have. And we circled the one that we're going to focus on.

You can see, the one that I'm just going to highlight right here is the weighted average price of dollars per KW month. It's about $3.10. You can see that capacity, and this is just for RA capacity, it doesn't include tolling arrangements, and it doesn't include long-term contracts.

So, you can see that the prices in the north are less expensive than the south. You can see that that pattern continues to be the same for local RA capacity. Strangely, it changes for system, but I'm not exactly sure why that is right now. We have to put this out next month, with the RA report.

So, I just want to talk a little bit about costs. So, how much does this cost? So, if you use $3.10, which is the average RA price, and using 2016 requirements, that's about $1.5 billion annually. Alternatively, if you use the CPM, the capacity procurement mechanism, there's a soft offer cap, and the soft offer cap is $6.31 kW a month. Applied to the 2016 requirement -- sorry, there we go. Applied to the 2016 monthly requirements, it translates to about $3 billion annually.

And using CONE, which is the cost of new entry, at $14.00 kW a month, that translates into about $6.5 billion annually. So, for CONE we used the figure in the 2015 CAISO report, which relies on CEC data. So, there's nothing magical about this.

The cost, the annual levelized cost for CTs and CCs were estimated to be 165 a kW year and 175 a kW year, so I just used 170 there.

So, the point of this is to say that we don't pay everyone our -- the RA price, and we also don't pay everyone CONE. So, the amount is somewhere in between.

The other point to make is that this is for capacity, only. This isn't for energy. So, these are, you know, someplace between 1.5 and 6.5 is what we pay for capacity every year.

So, I'm going to turn to talk a little bit about early economic retirement. Just wanted to note that we have been here before. We opened the Joint Reliability proceeding, in 2014, to consider policy proposals to refine California's existing reliability framework. And, also, to assure that the framework adapts, as needed to meet the changing requirements of the grid.

So, we would note that this proceeding was closed in 2016. And the primary reason that it was closed was that the development of a permanent flexible capacity issue was scoped into the RA proceeding, and it was determined that that effort needed to be finalized before a two- or three-year RA program requirement can be determined.

So, the reason for that is that we are -- we do have a grid that's changing, and we are trying to figure out which are the right resources to have under contract. You don't want to go forward with contracts that turn out to not meet those requirements in the future, so that would strand some capacity.

That decision also ordered the Energy Division to gather and disseminate information regarding expected resource availability and forward contracting for such resources, and to make that information available to the public.

The issues regarding long-term, let's see, multi-year RA were also moved into the CPUC's RA proceeding. And I put the number there because it's easier for us to follow.

So, I just wanted to make a point about planned versus unplanned retirements. There are significant planned retirements that are expected between now and the beginning of 2022. And you can see these are the once-through cooling units. I would also note that Diablo Canyon, which is another 2,000 megawatts, is expected to retire in 2024 and we're starting to plan for that, now.

Some of these resources had indicated that they are going to retire earlier than the once-through cooling dates, and those include Pittsburgh and Moss Landing. But in total, this is 9,380 megawatts.

So, with regard to the planned retirements, the CPUC and the ISO have been working to address these issues. In the, I believe it was the 2012 LTPP, the CPUC authorized additional procurement to address local reliability needs, particularly in the Southern California Region. So, we have addressed that and we have authorized additional procurement to replace some of these retiring units.

So, turning to Energy Division's data collection efforts, we issued a report in the fall of 2016 regarding contracting. We also issued new data requests in 2017, and we've received responses just recently on forward contracting practices of the IOUs, the CCAs, and the energy service providers. We're currently in the process of analyzing that data, but we're going to give some preliminary results and discuss them.

So, this is going back a little bit. These were the results that we showed in the fall, but it was based on October 2015 data. So, it was a little dated at that point in time, but we just wanted to show that we do forward contracting. The utilities have utility-owned generation. And you can see the green bar is the forward contracted capacity.

The other issue is on a system level, at least as of now, we do have additional resources to contract with.

So, these are some of the preliminary results from the data we just received. This is from the system perspective. So, the red dotted line is the load forecast. The black line would be the requirement, which would be based on load plus the 15 percent planning reserve margin.

So, you might look at 2017 and say, hey, we're not meeting our requirements. But as you recall, our forward requirement is 90 percent of the 115, and the year ahead, and then it's only the month ahead that they have to meet the 100 percent of the 115 percent of load requirement.

So, you can see, again, we do have utility-owned generation and we do have long-term contracts. Most of those represented in green, over time.

So, these are for the local areas. This is for -- based on the current data. What we have done here is we have aggregated all the regions in the north. So, for 2017 it looks like we have sufficient capacity.

And I should say a note about the forecasted RA requirements. The CAISO usually does a midterm local assessment. So, for example, in 2013 they would go forward -- no, the 2018 that are the requirements that are in their draft final. For 2019, those would have been developed in 2015. For 2020, it's a five-year forward. So, you can see they change year to year a little bit.

So, it looks like we probably -- so, from this graph it looks like we probably have capacity under contract in the north. But since we've aggregated so many regions, this would hide any over-capacity procurement in some local areas and under-capacity in others. But on the whole, yeah, we've got it there.

We've done the same, we've aggregated the south. Here, we've aggregated L.A. Basin, Big Creek, Ventura, and San Diego IV. So, you can see that we have sufficient capacity, in 2017, in the local areas. 2018, it looks okay. But recall that since I've aggregated -- since we've aggregated the regions you could have additional resources in one particular area, but you could still be deficient in others.

So, the reason we've aggregated these is due to market power concerns. I know a number of parties have raised issues about providing additional granularity, and we will consider it and talk about it some more. But we really do need to ensure that we are not exacerbating any market power concerns and, also, that we're ensuring confidentiality to the extent required by our rules.

So, just turning to forward procurement, uncertainties and challenges. So, there are -- I've sort of categorized these into system, local and flexible uncertainties.

So, with regard to system RA, there's always load forecast uncertainty. So, this would be your forecast of the economic conditions. It would also be your forecast of the solar PV and energy efficiency penetration.

So, for example, in 2013, or 2015 forecasting 2018 load, it's probably going to look different than if we forecast as we forecast 2018 load this year. So, there's forecast uncertainty.

There's also load migration. So, you might have load three years ahead, but you might lose load or gain load in the intervening years. So, we just raise that issue.

So, with regard to local RA, there's similar concerns. Remember, this is based on a load forecast for a 1-in-10 weather year, and that's going to change over time based on economic growth. Also, based on solar PV, and energy efficiency penetration, as well as considerations of peak shifting issues, which the CAISO has raised.

It's also going to change the local requirements depending on the contingencies. So, you might identify the worse things that are going to happen. So, the very hot day and two things going on, but that could change over time. So, due to the changing topology of the grid, or just additional information, that might not be as steady as you think it is.

Again, load migration. So, you might be serving load in that particular area, but you may gain or lose that over time.

Finally, I just want to say that you could have -- I think I mentioned changes in topology of the grid. But local area boundaries can change. So, this doesn't happen often, but to the extent it does, you could be procuring, potentially procuring the wrong resources. So, if the requirement were 5,000 megawatts, but the boundaries changed and it's now 6,000 megawatts, you might put the wrong resources under contract. So, we definitely need to consider that.

So, with regard to flexibly RA, what are the uncertainties? Well, one issue is what resources do we actually need to integrate variable resources? And we are working on that in FRACMOO, as well as the RA proceeding. So, the question is, which uncertainty do we want to address? Is it the minute-by-minute uncertainty? Is it the day-ahead ramp? So, I think these are the things that we're trying to identify at this point in time.

The other thing to note is that the durable flexible product has not yet been developed. So, to the extent that you want a forward contract and the product changes, you could strand some procurement.

So, finally, I just want to talk about reliability cost and the changing structure of the grid. So, I like to remind myself of what we're aiming for here. And from the PUC's perspective, we are trying to ensure safe and reliable service at just and reasonable rates. This always requires consideration of both reliability and cost. The PRM is a very good illustrator of this. So, you could -- RPRM is 15 percent planning reserve margin. You could have a higher planning reserve margin, but that would cost more. You could also have a planning reserve margin, likely cost less, but you are training off reliability and costs.

I would also mention that we have a third thing that we're also aiming for, and that's GHG reduction. And, so, that has to be considered, as well, trying to balance all of those things.

So, as we think about forward procurement, I just want to mention that we want to keep in mind how the grid is changing. So, there is increasing penetration of renewables which is affecting the existing resources. But it's also going to affect the resources that we want to have under contract in the future.

I also want to mention the retirement of the OTCs. This is going to change how the grid operates, but it also might provide opportunities for resources that aren't under contract, as the OTC units retire.

I also want to mention gas supply issues. As you know, we have some gas supply issues in the south. And as we think about forward leads, we also want to keep in mind that we may need to take into consideration gas supply.

Finally, I just want to note what's on a little people's minds and that's the growth of CCAs. So, as CCAs grow, we will have to be thinking about how we do procurement and how CCA growth will affect procurement.

So, if you have any questions, my name is Michele Kito, and Jaime Gannon can also answer them as well. She worked with me on this and did a lot of the data analysis. Thank you very much.

CHAIR WEISENMILLER: Yeah, just a couple questions, Michele.

MS. KITO: Sure.

CHAIR WEISENMILLER: One is, under the current rules for -- how do they apply to CCAs or to ESPs for resource adequacy?

MS. KITO: Sure. So, they all of the -- the CCAs and ESPs have the same requirements for RA. They have to show system, local and flexible resources the same way the -- yeah, they all have the same reporting requirements to us. And we have enforcement authority to fine them, if they don't do so.

CHAIR WEISENMILLER: Great. And, also, in terms of just trying to figure out a little bit better how to figure out a little better on how to deal with the sort of market power issues versus reliability.

MS. KITO: Uh-hum.

CHAIR WEISENMILLER: Just from your sense, how different is the RA within these local areas? I mean, if you were to disaggregate, how bad or good would it look?

MS. KITO: Well, some areas are very small and very constrained. So, if you look at some of those areas, let's see, if I go back to, let's see -- so, if you look at Humboldt, for example, the LCR requirement is 157 megawatts. There is UOG. But you can see some of them are much smaller, so you might have market power concerns. Yeah. And, then, the other thing to add onto that is there are also sub-area requirements. And, so, we might not be needed -- we are needed for the local requirement, but you also might be needed for a sub-area requirement and those can be even smaller.

CHAIR WEISENMILLER: I guess part of the question, again, at a very high level, is just, you know, utility-owned generation, I'm assuming -- I don't -- again, looking at this outlay, some utility-owned generation, presumably, would deal with the market power questions and other areas have lots of other resources.

MS. KITO: Yes, that's right. So, yes, some areas do have more utility-owned generation that could meet it, which would mitigate the market power concern somewhat, that's true.

CHAIR WEISENMILLER: Yeah. The last question was just thinking on the flexible, Tom had mentioned the under ten -- well, the 9,000, whatever, minimum generation, which is obviously one day out of the entire year when you're looking throughout the seasons. Looking at the Energy Commission forecast of, basically, behind-the-meter solar, it's pretty easy to look out, say, ten years and see like another 10,000 megawatts. So, basically, that would tend to be driving things to much greater ramps. I just want to figure out how that forecast is featured, you know, is being built into your thinking?

MS. KITO: So, a couple of points. So, yes, it's true. So, we did have a very low net load ramp. But remember, the -- I've been looking at these every single day. So, it appears to be that weekends are particularly difficult. Weekdays are a lot easier. It appears to be the wind and solar combined will lead to it. So, it's not an everyday phenomenon. It's true that we have very aggressive forecasts for behind-the-meter PV. And I've also been looking at those monthly to see whether the revised rate structure is having any effect on the market.

So, the other thing to remember is that when you have additional behind-the-meter PV, it doesn't translate one for one. So, you have to know, if you have 10,000 megawatts of PV, how much does that translate into load. So, it's a complicated question.

I don't want to -- I don't think we want to -- I think we want to look at the entire 8760. So, I think it's important to keep in mind that the needs change throughout the course of the year and that we want to meet all the needs.

VICE PRESIDENT DOUGHTY: Michele, agreed, and thank you for that. As we look at the duck, and assess the trending that is taking shape going forward, the statement that these curtailments and these over-supply scenarios are manageable today, using curtailment for example, is true. One to two percent of renewable generation is currently being curtailed.

Where we're seeing the challenges, as we look ahead, and the trend lines are ramping. Just as the belly of the duck was ramping to become deeper, the rend lines in oversupply and curtailment are growing.

So, we see ourselves being at the precipice of a highly challenging situation. But you're right, today it's being managed.

What we're trying to do, in the coming set of analyses we're performing now, is take a look at the duck over the 8760, and make sure we've shown the representative over-supply periods. Because there's going to come a time, relatively soon, when that's no longer just a spring phenomenon, it will start happening more and more prevalently across a wider, and wider range of the year. In fact, by 2030, we anticipate seeing over-supply most times of the year.

So, Chair, this is part of what I was trying to get to when we kicked off this morning is we believe we're sitting in the early stages of a tremendous planning horizon opportunity. We've just got to get our hands around what the trajectories are that we're planning to.

MS. KITO: Yeah, and I would like to say is that when the CAISO initially put out the series of duck curves, starting in 2014 to 2020, I recall that what we're planning for was 33 percent penetration in 2020. So, because of the ITC and acceleration of a lot of the solar assets, we are beyond 33 percent. So, it's not really surprising that we are seeing low net load. So, if you think of it in terms of what we've accomplished, I think it is not surprising.

In terms of what we're going to see in the future, I do think we have to think about the build out trajectory and the effect of that. So, yeah.

CHAIR WEISENMILLER: Thank you.

MS. KITO: Thank you.

MS. RAITT: Thanks, Michele. So, next, we have a joint presentation from the California ISO, with Greg Cook and Neil Millar, starting with Neil Millar.

MR. MILLAR: Thank you. Thank you and good morning. So, the first thing I'd like to do is I have a few slides that really just enforce some of the concerns that we already talked about this morning, setting the stage for the actual analysis that we undertook.

So, just building on what we had heard about earlier, in terms of the risk of retirement, we see the potential there coming from a number of sources. The growth of renewables, obviously putting down the pressure on pull price. The rather fierce competition we see for any sort of long-term contract from generators that are approaching us, raising their concerns about retirement. And, of course, the anticipated shake out of the gas fleet, as we all recognize there will be some reduction of the gas fleet as we move forward.

Now, setting aside the once-through cooling generation, we're not really aware of a clear, coordinated process moving forward around which gas-fired generation, and when, will otherwise respond to certain economic pressures and retire.

So, an important question for us, on the infrastructure side is looking at what level of retirement does provide comprehensive reliable service and are the right resources leaving it in the right order.

So, in this graph I have just provided an overview of the generation fleet as it stands today, and both emphasizing the continuing growth of renewables, as well as the large role that solar energy is playing in the renewables.

In the upper right-hand corner we're also just showing the downward trajectory on overall market revenues available to other generation.

The one point I wanted to make, besides this being the one mandatory appearance of the duck curve in today's presentations from the ISO, which takes Greg off the hook, is that the one point I wanted to make on this graph is besides the resource characteristics changing, that everyone's very aware of, we also have to remind people that the resources that are carrying us through the afternoon, being the renewables, are not physically in the same location as the other resources that are backfilling through the peak of the day, now, occurring in the 6:00, 7:00 time frame.

Now, that’s important to us because besides managing system frequency, at a holistic level, we also have to manage grid reliability, keeping things within stability limits, voltage limits, as we manage the transition from one resource pool to another, and back, on a daily basis.

In looking at the overall risk to the system of, say, a material amount of unplanned retirement, we were looking at both the system side, as well as the transmission grid side. On the system resource side, obviously there’s the concern with ramping capability, peak capacity, and maintaining sufficient capacity for that post-solar peak.

And in a number of parts of the system, the behind-the-meter solar generation has already shifted the peak load in some areas to periods outside of the conventional solar window.

Now, from a grid perspective, we’re both looking at maintaining the local capacity needs, as well as exploring whether or not new reliability requirements would be building up in areas that weren’t traditionally identified as local capacity areas.

The other issue we have to consider is that much of the transmission system was built up around certain generators, and counting on them to be there, and they were incorporated into remedial action schemes for transfer capability, and so forth. So, we also need to explore what impact there might be on those arrangements.

So, in the 2016-17 transmission planning process, in addition to our tariff requirements and our mandatory standards requirements to conduct analysis, we also did a preliminary study looking at if a material amount of generation required, what were the consequences? How well prepared are we? And where are the areas where we should be applying additional focus to help mitigate the risk should this actually occur?

Now, we were looking at system wide resource needs, as well as the transmission grid needs. We were also looking beyond, as I said, to see if there were pockets of where, potentially, a larger number of similarly situated resources might be feeling the same economic pressure at the same time, and retire in an uncoordinated fashion.

And we've laid out all of the details and assumptions for that work, looking at a 50 percent RPS scenario. We've laid out the details on our website, as part of the '16-'17 transmission plan. I won't try to walk through all of the underlying assumptions here, but the information's there for those that are interested.

The scope looked at the impacts on various transfer paths within California. We were also looking to see, test as I mentioned, for any impacts on our remedial action schemes, as well as to study the impact on the system level requirements for ancillary services and flexible requirements.

Now, we started looking at two different scenarios, by first looking at the drop off in market revenues available to gas-fired generation, as we move from a 33 percent scenario to a 50 percent scenario. And we identified the generators, in the various areas that we saw, at risk from purely those market signals. And, then, also took into account and shielded generators that were already receiving material compensation for ancillary services.

The second scenario that we looked at was to further reduce the amount of system -- or, increase the amount of system generation retirement, that could potentially occur, by transferring some of the ancillary service obligations that those units were helping with, to units that were already assumed to be protected inside a local capacity area.

So, that resulted in an increase in the amount of potential retirement on the system basis, which is on the furthest right set of columns.

Now, we then conducted all of our traditional reliability analysis from a transmission grid perspective, looking for any challenges that were created. Not surprisingly, we did identify a few transmission issues. And we've listed those in the first three bullets.

The impact on remedial action schemes did have some impact on our north/south transfer capabilities through path 26. That showed up, in particular, in the sensitivity case that we looked at, modeling some retirement in the midway area. Now, at the same time, though, we were also seeing less transfer from north to south because of the generation retirements. So, a slight drop off -- sorry -- sorry about that. A slight drop off in north-to-south transfer capability isn't necessarily problematic, if we're also seeing lower north-to-south flows.

We also did identify some issues in the L.A. Basin area and, also, the Victorville Lugo transmission line, which has shown up in other transmission planning processes as needing some mitigation, also showed up there as well.

Now, the bottom line, from a local capacity perspective, is that if the local capacity needs, as identified, are respected and managed, we really aren't seeing anything that's not manageable from a transmission grid perspective, as we looked at some fairly progressive retirement scenarios. That really helped validate that the local capacity areas being selected in the first place really did hit the target. So, that's the most important issue for us is ensuring that those needs continue to be respected.

Now, the area where we did see more of an issue was on the system wide requirements. And this is where we're backing away from the local issues and looking at the overall flexible needs, ramping needs.

And what we did there was we took our range of retirement scenarios and looked at six different increments of steadily increasing retirement, also assuming that the units that, in our screening, were identified as being more at risk were the ones to go first, even if they had the best characteristics that we would ideally need for ramping.

So, we were looking at this -- like I said, looking at this from the economic perspective of generators dropping off, without the benefit of any sort of centralized, coordinated process.

Now, what we saw, and the results are spread over the two graphs here, we did always assume that in facing a capacity shortfall, that we would first see some reduction in load following capability, then non-spinning reserves, then spinning reserves, and that we protect regulating reserves basically last, and at all cost.

So, as we do see growing levels of retirement, we also see growing issues of cutting into load following needs, and then eventually progressing where we start having shortfalls on non-spinning reserves, spinning reserves and then, ultimately, regulating reserves.

Now, this graph is looking at the megawatt impacts of where we saw shortfalls. And the next graph is focusing on the number of hours where shortfalls started to occur. The results here are probably, for the level of uncertainties we're dealing with, it's a fairly wide range.

But our conclusion is, really, that between the four and six thousand megawatts of retirements, beyond the scheduled retirements, so this is in addition to OTC generation, and so forth, that between four and six thousand megawatts we start to see material issues emerging in terms of being able to provide adequate frequency control and load following capability.

So, that's really the summary of our system resource finding. We do have to caution that the need for flexible capacity, especially during the downward ramping, that unlimited renewable curtailment may or may not be acceptable. But as long as we're allowing it, it does mask some of the capacity requirements that we would otherwise see.

So, that's an issue that we're really going to have to deal with on a more comprehensive basis is what level of renewable curtailment really is acceptable.

The shortfalls in load following and reserves were how we were reflecting capacity insufficiencies. They do generally occur in the early evening hours, when the solar output -- we said after sunset, but because of the angle of incidence on solar panels, it really doesn't have to wait until sunset for the solar panel input to drop off. But that's when we were seeing the most number of challenges.

And the last point I just wanted to reiterate is that somewhere between the four and six thousand megawatts of retirement is where we're really seeing the challenges start to grow, where that would be our threshold for where we're starting to get in trouble on needing to retain additional resources.

So, that concludes the presentation, be glad to help.

CHAIR WEISENMILLER: Yeah, a couple questions. First is both your analysis and the PUC analysis assumes average hydro. And, obviously, we've seen in recent years sort of swings from droughts to this year. So, have you thought of doing scenarios at low and, you know, at those two extremes on the hydro system? Obviously, the gas plans are going to operate a lot less in high hydro years and a lot more in drought years.

MR. MILLAR: Yeah, so we've taken a look, we haven't dived into doing a lot of analysis on the range of scenarios, because we were seeing that more as an economic issue. From a conventional reliability perspective, or reliability issue less so, and more of an economic issue. In looking at the economic risk to the existing gas-fired generation fleet, that is an issue that would need more analysis, but we haven't looked at it, yet.

And I should clarify, from the infrastructure side, we were not really trying to say how much revenue these units needed, the gas-fired generation needed to survive. We were more looking for commonality and groups of like-situated resources that would be seeing a drop off, on a relatively sustained basis.

So, that’s something we can give some thought to in the future, but we’re not trying to say this is how much should retire, it’s where do we start to have problems.

CHAIR WEISENMILLER: Okay, I have a question. If you look at ERCOT and, obviously, they tend not to even use the California vocabulary, there they talk about not ducks, but dead armadillos. You know, that they’ve done a recent study on inertia, you know, certainly switching from coal, gas, or whatever, to 18,000 megawatts plus, now, of wind. They were concerned on the inertia, although also one of the study results were that things were okay.

So, the question is how much have you been probing inertia?

MR. MILLAR: We’ve been studying the overall system stability issues and looking at the issues associated with the need for system inertia as part of our routine planning process, as well as in studying these 50 percent scenarios.

What we’ve seen is that, really, the inertia was there, and even traditionally the inertia was counted on in parts of California. Not so much for its stability performance, but also because it was all similar types of generation, and it was also a convenient shorthand for how much governor response was out there.

We have been studying the situation. We haven't seen any dynamic stability issues that required a higher level of system inertia, beyond what I would say is a governor type response. And the governor type response can be provided by renewable generation if you're willing to back it off so that there's some head room.

So, we're not seeing a reliability threat there, but there will have to be choices made on how the governor response and frequency response capability is provided as we move forward.

The other thing that the inertia, traditional inertia-based generation provided was fault current for protection and control. We haven't seen any problems emerging on our footprint that would raise that concern.

We have been relying fairly heavily on synchronous condensers in the L.A. Basin and San Diego area, as part of the loss of SONGS mitigation. Which do help provide some level of additional fault current. But in general, much of the Edison system is actually experiencing very high fault current levels. So, protection and control haven't been a problem, yet.

We do continue to study those issues every year, though.

CHAIR WEISENMILLER: They were thinking they might need to have an ancillary service market for inertia, and they concluded that it was not an issue at this stage.

MR. MILLAR: Yes, and I would say that that's what we're seeing at this stage as well. But I do want to reiterate that some choices will have to be made on where frequency response comes from.

And, like I said, grid-connected solar PV can provide that type of response, but only if it's not already running at maximum output. So, backing off a solar panel so that you can get an inertia-like response out of it, or a governor response out of it, still means some level of curtailment.

CHAIR WEISENMILLER: Yeah, and ERCOT, my understanding was they keep the wind not at max, but down, de-rate some, so that they can go up and down.

MR. MILLAR: And we currently don't have a situation, but it's something we need to watch.

CHAIR WEISENMILLER: And, actually, having said that, you know, it's sort of surprising, we're talking about like 60 hours even at the most extreme. Presumably, it's time to start thinking about some of the solutions that we might have for that limited time period.

MR. MILLAR: Agreed.

MS. PETERSON: Question. On these two slides, where you're showing the shortfalls, what kind of time frame are you -- what year do those show up?

MR. MILLAR: Oh, this was an attempt to model a 2030, 50 percent RPS. We were generally working off of either 2026 cases, developed for our 10-year transmission plan, recognizing that there isn't a lot of load growth. So, we were trying to do a crude estimate of 2030 conditions, but working off of available cases.

CHAIR WEISENMILLER: But I assume you really mean you're looking at a 50 percent renewable case if we hit it in 2030, or 2026, or 2020, you would have the same issues?

MR. MILLAR: Right. So, we were modeling 50 percent generation scenarios on 2026 cases, just to take advantage of the work that was already done in the 10-year planning process.

VICE PRESIDENT DOUGHTY: Neil, forgive me if I didn't catch this and you covered it. Would you expand a little bit on the cases that you used in the analysis for risk of retirement, such as a lack of RA contract, OTC, voltage. Were there anything else that didn't get touched on there?

MR. MILLAR: I think the only other -- we are assuming, of course, the retirement of Diablo Canyon and the once-through cooling generation. The only other thing we did was on the system side, in the Southern California area, we did further adjust beyond the results we received from the screening for economic purposes. And we simulated the retirement of an additional up to 2,000 megawatts, in some scenarios, of generation that have come to us and told us of their plans to retire. And that we were testing to see if there were any reliability impacts.

VICE PRESIDENT DOUGHTY: Thank you.

MR. MILLAR: Thank you very much.

CHAIR WEISENMILLER: Thank you.

MS. RAITT: Thanks. Next is Greg Cook, from the California ISO, as well.

MR. COOK: Well, good morning, everyone. So, I wanted to give a brief overview of some of the policy development that we have planned for this year, and even looking over the next couple of years, as well, to address some of these issues.

Let me start off with I think if the Resource Adequacy Program is working well that it would provide for the efficient retention and retirement of the resources that we need to maintain reliability going forward. And in order to do that, we need to have the policies in place that would ensure that the capacity prices properly value the resource operational characteristics.

And to do that, we need to develop those requirements that are aligned with the operational needs. And, again, as Neil was looking at, we need to be looking forward to what these needs may be.

You know, back when the Resource Adequacy Program was established, back in 2006, given the nature of the fleet at the time, it was a largely conventional fleet, if we were able to meet that fleet load back in July, pretty much all of the operational attributes that we needed kind of fell out of that. So, we didn't necessarily need to pay a lot of close attention to that.

But as we've evolved and have a significant amount of renewables on the fleet, and that's continuing to increase, we're having to align those resource adequacy requirements with those operational needs.

We took the first step on that with the flexible requirement. But I think, admittedly, that was only looking at one aspect of the operational need, that net load ramp. But there's other needs that we need to pay attention, that we're looking at in the future, as well. We need load following, making sure we have sufficient regulation, meeting those ramping needs. As well as some of the minimum load issues that we're having in the middle of the day, today. And, again, that's going to come down to ultimately, the policy on renewable curtailments, how that ultimately pans out.

Also, I think it's important that we align the resource adequacy requirements with the integrated resource planning programs that are currently being developed to efficiently meet our grid reliability needs. We should be -- the same objectives that we're trying to meet in the IRP, those should follow through, through the RA, so that the resources that are being procured through the IRP program are also, then, being the ones that are being contracted for through the RA program.

And, finally, looking at the ISO, we need to enhance some of the process that we currently have in place to identify and help facilitate efficient resource procurement and retirement. And I'll go into a little more on those in a minute.

And, then, next we need to start looking at establishing resource adequacy rules for distributed energy resources and storage. This is an area that, you know, we anticipate is going to continue to grow as we look forward. And, so, we need to establish the rules for supply and load-modifying distributed energy resource and storage resources. That includes establishing the accounting rules and offer obligations for those resources.

And then, also, accurately forecasting the load that's being served by behind-the-meter resources, so that those -- that can be put into our forecast, as well as the planning tools that we use.

So, we have a couple of initiatives underway, as well as some plans as to how we're going to address some of these risk of retirement issues. What we currently have underway are FRACMOO2 initiative, which is flexible resource adequacy criteria and must offer obligation. The 2 is there. The FRACMOO was the initial initiative that we put in place to help establish the criteria for the flexible resource adequacy product.

But as we've looked at how that's been performing since it was put in place, in 2015, we're finding that a lot of the resources that are being shown as meeting those flexible requirements, are not necessarily the resources that are going to be meeting the needed operational needs in the future.

You know, a lot of the resources being shown to meet the flexible need, since we're only looking at that net load ramp, tend to be a lot of the long-start OTC resources are encompassing a lot of those requirements.

And, so, we're looking at some short-term enhancements that we can do on the eligibility criteria to ensure that we have a more effective way of managing those resources and ensuring that we do get the proper resources shown to meet the flexible needs of the grid.

In addition to that, we're looking at perhaps a consideration of longer-term resource adequacy reform. And this really comes down to the fact that the needs of the grid are changing quite a bit from where they were when we first establish the Resource Adequacy Program.

We think it makes sense to, at this point, step back, let's look at how is it performing today? Is the rules that are in place going to be efficient and be effective as we look forward into the future?

And, you know, as we have the separate requirements for system, local, and flexible, I think we're seeing there could be some interdependencies among those requirements that it makes sense to look at what are some of the longer-term changes we can do, to make sure that the resource adequacy requirements are aligned with the future operational needs.

And then, finally, we have our energy storage and distributed energy resources initiative underway. And this is an ongoing initiative. And, again, it's providing to set up the rules for supply and load-modifying distributed energy resources, and storage, and how they can operate within the ISO's market.

One more initiative I'll add on here, is we also have our frequency response initiative underway. We have new NERC requirements that were put in place, starting last year, that require the ISO to maintain its share of the WECC frequency response obligation.

And what we've found is particularly during periods of high renewable output, and low load periods, there's times when we don't have sufficient frequency response on the system.

We put in place a short-term -- short-term rules that allow us to transfer some of that frequency response obligation over to other balancing authority areas. But we're currently running an initiative, now, to where we can turn that into a market product, to ensure that we have sufficient frequency responses, as well, available through our market.

And, again, that could be -- we're still working through the details on how that product would be designed. But, ultimately, it would allow for resources within California to provide that product. But if they were providing that product, then we may have to dispatch them in a way that maintains certain head room, so that they can provide the frequency response in the event that it’s needed.

And then, finally, we also have a couple of policy initiatives underway to address when we do -- we are anticipating more resource retirement requests coming to the ISO. We need to make sure that we have efficient processes for dealing with that.

We have our capacity procurement mechanism, risk of retirement provisions currently in place, but we’ve found that there are some issues with how that process currently works. A couple of the problems that have been raised for us are that a lot of times we’ll have resources that are looking like they’re not commercially viable, they’re pretty sure they’re not going to get a resource adequacy contract. But the way the current policy is established in our tariff, we can’t even start to look at those resources until after October 31st, to ensure whether or not they actually did receive a resource adequacy contract.

There’s need for these resources to have earlier notification as to whether or not they’re going to be needed or not, so they can start doing the things that they need to do, in the event that they are going to retire the facility.

And, then, we also need to have policies in place for new provisions to address the fact, when we have multiple resources coming into us, at the same time, wanting to retire, to ensure that we have the proper analysis in place so that we select the right resources to retire, and retain the ones that we may need in the future for our operational needs.

And then, finally, we call this long-term economic outages. We've been struggling with what we were going to call this initiative. I think it's really what we're talking about here is a unit that wants to go temporarily out of service. Because they don't feel that they're commercially viable in the short run, but they do see as the system conditions change, they may be commercially viable in the longer run.

So, this would allow a new outage type on our system to where that resource may not be needed for the next six months or a year, we would allow them to take that out of service and then come back, in the future, when it is needed. So, those are -- that's currently a gap that we have in our current tariff, because we don't allow for those types of outages.

So, that's kind of the plan of what we have in the short term to address some of these issues, and some of our thoughts on the longer term. And I'd be happy to answer any questions.

CHAIR WEISENMILLER: Yeah, at this stage, what's the magnitude of the energy storage and DER resources on your system?

MR. COOK: Currently, on our system it's fairly small for the ones that are actually participating in the market. I want to say a couple hundred megawatts. Obviously, there's the behind-the-meter, which is thousands of megawatts.

But, you know, I think our anticipation is that that's something that's going to grow fairly rapidly over the next several years, and so we need to be prepared for that. And these rules need to be established so that the resources can know whether or not it is economically viable to develop these resources.

CHAIR WEISENMILLER: Yeah, in terms of economic outages, you know, for -- this spring is, obviously, we're going to have high hydro. If people -- I assume are scheduling maintenance, whatever they can possibly do to get offline? Have you seen any?

MR. COOK: Yeah. I mean, we tend to see most of our maintenance outages in the fall, that's the primary, the prime time maintenance season.

CHAIR WEISENMILLER: Right.

MR. COOK: But, you know, I do think that we have resources that are, you know, looking at the market conditions, and grid conditions as well, and potentially coming offline.

You know, the challenge is that we still need a lot of the flexibility from these resources, even with the high hydro conditions, because we're still needing to meet those ramps in the afternoons.

VICE PRESIDENT DOUGHTY: I think there's another observation, and I see some of our colleagues from the IOUs here, who were on a call with us last week, talking about this.

When we looked at the hydro flows that were anticipated for this spring, we expected them to really, seriously impact the over-supply issues. But as we see prices begin to fall, our sense is that hydro is taking itself out of the market because prices are so low. So, we're seeing a lot of hydro spill.

We're doing some analysis, now, to get our hands around that. No matter how you look at it, it's low GHG production that's not being utilized by consumers. But the hydro impact on over-supply is playing out differently than we originally anticipated.

And maybe the IOUs can speak to that, as they take the table later today.

CHAIR WEISENMILLER: Yeah, certainly a question for the IOUs is this bid on the hydro, particularly in this high hydro year, between run of the river and pondage.

MS. PETERSON: Yes, can you give a sense, a little bit unpack the technical issues that FRACMOO2 is going to be addressing?

MR. COOK: Yeah, FRACMOO2, it's fairly narrowly scoped because of the fact that we're trying to come up with short-term enhancements to where we can have them implemented relatively quickly, and coordinate with the CPUC's process as well.

And, so, what we're primarily looking at is the viability of having long-start resources providing flexible capacity.

And the real issue there is, particularly when we look at our short-term unit commitment process, if we have -- we want to make sure that we have -- it doesn't necessarily look out far enough to see both the morning ramp and the evening ramp. So, if you have long-start resources that were starting up to meet that morning ramp, they may -- we're not necessarily seeing far enough forward to the evening ramp, so we may not have them available for that.

And, furthermore, if we don't commit them in the day-ahead market, then those long-start resources have no obligation to be available in the real-time market, which is when we have a lot of our flexibility needs due to, you know, forecast errors from the day-ahead market, and those types of things.

So, you know, in our mind it makes some sense to ensure that we have the resources that are going to be available in the real-time market, and that are consistent with how we do our commitments in the real-time market, that they're able to start up quick enough in order to meet the flexibility requirements.

MS. PETERSON: So, do you anticipate that there will -- the process will result in some closer definition of attributes that could be incorporated, perhaps, into our RA Program?

MR. COOK: Yeah, our plan is to really see if we can enhance some of the eligibility criteria, I guess is what I call it, for flexible capacity. We would run that through a stakeholder process that we're working on, through this spring and summer. And, then, we would submit the findings of that into the CPUC's RA proceeding next fall, for consideration there. Because, again, we want to make sure we can again, to the extent possible, have the backstop provisions and the procurement provisions aligned as much as possible.

MS. PETERSON: And, then, let me see if you just agree with this statement. There are a lot of tensions in this arena. But isn't one tension between developing a multi-year RA, forward contracting requirement and the constantly changing needs of the grid? Isn't it possible that the grid needs would change year to year, and a forward contract could result in contracting with a resource that does not provide what the grid needs the following year?

MR. COOK: Yeah, I mean that's a possibility. I think, you know, there's two sides to that coin. That there's that issue. But then there's also the issue that the needs of the grid for like -- let's take flexibility, for instance, are increasing as we look out, so that the requirements for next year may not be high enough to secure a resource that's going to be needed two years' out. So, that resource doesn't get a contract, then they could be at risk of early retirement, where they're going to be needed in a future year.

Whereas, if you had a longer-looking RA requirement, you can address that issue.

But, you know, your point is a good one. It is challenging because you want to -- the grid conditions are changing quite a bit. You know, it's we try and forecast forward what our needs are going to be. But, you know now, I think there needs to be some flexibility in that. And, you know, normally how you'd address that is you don't buy a hundred percent of your needs three years forward, it's some percentage of that. But then, maybe, you're not really addressing the problem because it's those ten percent of the ones that are really at risk of retirement in the first place.

So, you know, I think it's something we do need to look at, though.

CHAIR WEISENMILLER: Thanks.

MS. RAITT: Thank you. So, I think, then, we are ready to take a break. And we'll stick with the schedule of starting back at 12:30.

And, again, if you wanted to make comments at the end of the day, please fill out a blue card. I got one, but they're at the entrance there, if you could go ahead and fill one out.

CHAIR WEISENMILLER: Great, thank you. So, we're adjourned until 12:30.

(Off the record at 11:22 a.m.)

(On the record at 12:31 p.m.)

MS. RAITT: Hi, welcome back. We're going to go ahead and get started. We have a panel this afternoon to talk about the risk of economic retirement of California power plants.

And, so, if folks can go ahead and take seats, we'll get started with our panel.

And Melissa Jones, from the Energy Commission is the moderator. And I'll go ahead and give it to Melissa. Thank you.

MS. JONES: Good afternoon, everyone. I'm Melissa Jones. And good afternoon, Chair. And Commissioner Randolph, welcome.

Today, we're going to have a panel. We heard this morning from the agencies and from the ISO. And this afternoon we're going to get some different perspectives from the utilities and from the power plant owners.

And, so, we have four main topics we're going to be talking about. What power plants in California are at risk of retirement? Some for economic reasons. Are there others for environmental or other reasons?

How would power plant retirements affect local reliability and resource adequacy, from your perspective?

What are the desirable attributes and performance characteristics of power plants?

And what are possible approaches and solutions to meet the needs of the electricity system?

So, I think everyone wanted to make an opening statement, so we're going to allow three to five minutes for that. And why don't we start over here on my right, with Greg Blue.

MR. BLUE: Good afternoon, everyone. My name is Greg Blue, with Cogentrix Energy. And, yes, I am that Greg Blue which is on that footnote number 8, of the 2003 IEPR. You can look it up yourself, it's online. And the topic I was talking about that time was the retirement of existing generation. So, we're back again. Hopefully, we'll have some solutions.

With me today is also Jeff Spurgeon, who is from our Charlotte Office, and is here to help with any technical questions that we may have, as well, that I might need some assistance on.

So, Cogentrix manages six -- well, let me back up. We heard about, this morning, about a lot of the issues that are upcoming. And it seems like a lot of the issues that they're talking about are a little bit -- they're coming, we can see them coming, these issues.

But from Cogentrix's point of view, the issues are here, now. We manage six flexible, fast-start peakers, located throughout California. And two of those are not under contract. The ones located in the San Diego Sub-area. Three of those are out of contract at the end of this year. And one of those is under a long-term contract.

So, these issues are very pertinent to us and we've been kind of vocal on some of these things.

As we know, as was stated earlier, as everyone knows, the peaker plants only run maybe 5 to 10 percent a year. That's their -- a 10 percent capacity factor is a good year. And based on what we heard about the pricing and so forth, you're not able to recover all your cost if you just -- just from the energy market.

So, these kind of peaker plants require some form of capacity payments. And the only opportunities we have, now, for capacity payments are through the RA contract, the resource adequacy contract, or the RMR contract, reliability must run.

We believe that the existing fleet of peaking resources are an essential bridge to the future, low-carbon grid. And as we've seen, as more intermittent generation is added to the grid, more tools are needed, including the fast-start peaker.

One of the things I will say is, you know, I want to -- a couple things. I want to focus on the GHG impacts of both our plants, and some of the things that are happening in the market.

The peaker plants, because of their short run time, as I mentioned before, really, the GHG footprint per megawatt are significantly lower than both combined cycles and the existing once-through cooling plants. So, that's kind of setting the framework.

I'm just going to list some of the problems and I'm going to list some solutions, and we'll be happy to talk more about these as we get through the discussion.

So, starting with the problems. Steve Berberich, the CEO of the ISO, at the March 15th Board meeting, basically, in discussions regarding approval of an RMR contract, basically said it's an indication of a systematic market failure. And, so, that was what he said.

As we heard earlier, the RA market is depressed, with weak prices, due to the short term nature of the contracts. I think renewable generation is assigned too high of an RA value. That's my own opinion. And utilities have procured so much solar that they're actually selling RA back to the market, which is further depressing the pricing of that market.

We've heard a lot about the duck curve. That's coming faster, steeper, more often than we originally estimated. In fact, every time I'm going to the ISO or see the ISO, I'm hearing about a new record. It's either a new record ramp, or a new record net low. Which we just heard this morning about another record net low. Which, again, that's the belly of the duck. And the lower you go, the ramp's going to get steeper and longer. That's an issue.

The other issue is that California, and I'm going to say California when I'm referring to the three agencies, and I'm going to call you agencies for this. But I'll just say California, rather than repeating all the names.

But California currently allows 60-year-old once-through cooling plants, and other long-start generation to count as flex capacity. Which means, as we heard earlier this morning, as well from the ISO, these units have to be dispatched the day before to be available and they have to run all night long to be available for the morning ramp, and all day if they're there for the afternoon ramp. This does not support the State's GHG goals.

California also supports extending the Encina once-through cooling plant, currently scheduled to close at the end of this year. Meaning another year of high GHG emissions, another year of effects to the sea around that area.

And there's also discussions of extending Alamitos and Huntington Beach once-through cooling plants, as well. Again, this also does not support the

State's GHG goals.

One last major problem is all the forecasts that are used by the ISO, the PUC, and the CEC, they all show -- we saw one this morning, they all show uncontracted generation just being there for the next five to ten years. And I can tell you, that is an incorrect assumption. It's like, Tom, I'm going to offer you a job, okay. And the first year I'm not going to pay you, but you're still going to have your bills, because I might need you the next year. Would you stick around? I'm not sure. We'll see about that.

I know my time is up. Real quickly, a couple of solutions. One, tighten the criteria for eligibility for flex capacity. The ISO currently has a stakeholder process, but that's not going to be implemented until the 2019 or maybe 2020 RA season.

The CPUC has an opportunity to approve changes for the 2018 RA season, on this issue.

Second would be implement multi-year RA requirements on all LLCs, now, and which we believe will lead to multi-year procurement. Again, the CPUC has an opportunity to implement changes for the 2018 RA season.

And, then, if neither of these two actions can be accomplished for the 2018, then we have been proposing a one-time, transitional flex capacity bridge procurement program for existing peaking plants. And you would have to qualify for that, and there would be three- to five-year PPAs associated with that.

And with that, I'm going to look forward to answering more questions during the discussion. Thank you.

MR. SMITH: Good afternoon, this is Mark Smith, I'm with Calpine. Commissioners, thanks for inviting us. Tom, good to see you, too.

Calpine, I think, you know very well, has 7,000 megawatts or so of generation within the State. Some of that has long-term contracts. A significant portion of that is under what we call merchant conditions, where we have no contracts and sell into both California ISO and RA markets.

We, of course, have combined-cycle facilities, we have peaking facilities, and we have a significant number of geothermal plants up in Lake and Sonoma Counties, that I think you're very well aware of.

Virtually all of this capacity is located within local-constrained, transmission-constrained areas. LCR areas, as the ISO would call them. And I think that if you look at the ISO's LCR requirements, that look out only five years, but nonetheless five years, there is still a substantial amount of generation that's required in those local areas, for that long term of a duration of time.

Even though changes may happen over time, they will happen on the fringe, we think, and not wholesale changes to the amount of local generation that's needed.

Nonetheless, virtually all of this capacity is, you know, threatened or subjected to the retirement pressures based on current conditions.

So, we heard a lot about the current conditions this morning, but let's just touch on it very generally. The impacts of the secular change are staggering. Movement and building out generation, particularly in the renewable sector, wind, and more particularly solar, has resulted in energy margins absolutely collapsing. And RA prices have not moved to accommodate the costs of operating facilities in California.

As a matter of fact, many merchant plants, certainly the ones that I operate, struggle to cover their variable costs. There are other going-forward costs, including major maintenance.

As a matter of fact just last month, the month of March, this year, of my merchant fleet, say 2,200, 2,500 megawatts, depending on how you count them, we required almost a million dollars in uplift. Almost a million dollars of make whole payments in order to collect just our variable costs of operating. That should be a startling number for folks to understand. That plants that are being dispatched, fairly routinely, even under these conditions fairly routinely, are struggling to recover just their going forward costs.

And, by the way, no generator wants to operate in a market where the best you can do is recover your going forward costs, your variable costs.

At the same time, we see supply commitments, or tenor of contracts diminishing. That is specifically, and I think Mr. Lawlor will say this later that, indeed, most of the LSEs are long-generation these days, because of the out-of-market commitments they've made to the solar resources. So, more often, they're in a sell position in RA, than they are in a buy position. Which is, I think, a pretty stunning change.

The CCAs, the community choice aggregators, are almost always buying short-term capacity year to year.

Given these facts, it might be reasonable to ask why we continue to operate these plants in this environment? And that's a fair question, one that maybe we can take in Q and A.

But, nonetheless, I think that we have shut down a number of plants. We're continuing to evaluate which plants we should shut down. And we need your help to try to figure out what ones are the ones to keep. That's really purpose, I think, of this meeting in particular.

Right now, when the market fails to support resources, we have seen an effective use, just very recently here, of the ISO's backstop procurement mechanism. We went -- and I can talk more about this in Q and A, because I know I'm limited here. But we went to the ISO, seeking an evaluation of four of our peaking plants, similar to Mr. Blue's plants.

The ISO found, not surprisingly to us, that two of them were needed for reliability purposes. All of them were dispatched almost every day. We call them the sunset peakers, because as the sun goes down, they go up.

And, you know, we've found that two of those were needed for reliability and we're currently in the process of designing an RMR contract to accommodate the ongoing operation of those plants.

RMR is the backstop to the market power concerns for local area requirements. Again, I can talk more about that along the lines of the questions and answers.

But let me be clear about one final thing, I guess, here. Is that California needs a thoughtful and comprehensive plan to retain generation that's needed for reliability. We can call it a reliability insurance program that will extend through this transition, however long the transition might exist, to a world that reaches our aspirational goals of GHG reduction.

But that plan needs to be in place, an evaluation mechanism needs to be in place in order to determine which resources we want to keep. And I would assert that many of the resources in those highly-constrained local areas are needed, and will be needed into the near future. Thank you.

MR. THEAKER: Thank you, Mark. Thank you, Melissa. Chair Weisenmiller, Commissioner Randolph, Tom, thank you for the opportunity to address these issues today.

So, NRG is currently operating about 7,100 megawatts of conventional generation in California, 5,800 megawatts of that is within CAISO local capacity areas. We also have about 3,000 megawatts of those assets are once-through cooled units that, for all practical purposes, will be retired, fully retired by the end of 2020.

We also are operating another 1,200 megawatts of solar assets in the State, and we're aggressively pursuing energy storage projects, as are probably a lot of the people in this room.

So, to put this in perspective, let me give you just a few stats. In 2015, NRG was operating 9,500 megawatts of gas-fired generation. Last year, that number dropped to 8,500. This year it's 7,100. And the most likely future that we can foresee probably has this operating about 2,600 megawatts of gas-fired generation beyond 2020.

Let me give you just a couple of other interesting factoids from yesterday's, that load peak. Across the daylight hours, the ISO's day-ahead market produced prices that averaged negate $2.56. And the ISO's real-time market, from the hours of 7:00 a.m. to 5:00 p.m., produced prices that averaged negative $16.00 and change. So, that gives you a sense of what the system prices are on an over-generation day.

So, the reality is that to meet California's aggressive GHG goals, it's going to be necessary for the supply of electricity that comes from gas-fired generation has to be greatly reduced. There's no doubt about it. This is not a conversation about preserving all gas, this is a conversation about preserving the right gas.

So, and that's already happening. Year to date, if you look at energy statistics, CAISO thermal production is 22 percent below 2016 levels. Of course, that's thanks to the incredible hydro year that we're having, as well as the build out of renewables.

I'd note that it's 45 percent lower than this same period in 2014. So, we are driving carbon out of the system, there's no doubt about it.

But we have to remember that the electricity sector comprises only about 20 percent of statewide GHG emissions. So, we can squeeze all of the carbon out of the electricity sector and we still won't come close to meeting the State's overall GHG goals.

The reality is if we're going to increasingly squeeze carbon out of the economy, we're going to have to turn to the transportation sector. And to do that, I think we're going to need a very reliable electricity grid in order to meet the transportation needs that we see coming, to meet our GHG targets.

So, we can do that two ways. We can either greatly over-build a system of variable and short-duration resources, or we can maintain a prudent amount of gas-fired generation to maintain system reliability and local reliability through the transition.

Gas-fired generation has three really important reliability attributes. Availability, dispatchability, and duration. So, and currently, at present, the gas delivery system is a effective, if not the effective form of energy storage.

So, we believe that ultimately we have to drive carbon out of the system, but we have to have a reliable transition to that future. We believe that a fresh look at multi-year, RA requirements is the right structure for having that conversation.

So, thank you for this opening time and I look forward to the discussion today.

MR. CUMMINS: Paul Cummins, with Wellhead. Thank you for the opportunity to be here today. After my colleagues to the left of me have given their opening remarks, especially about the problem statement, I can't imagine what more I could say to add to it. They've done a great job.

I will say a little bit about Wellhead. Wellhead has eight facilities. Six of them peakers. Three of them uncontracted. All of our assets are in strategically important locations, and they're being called daily in the mornings, of course, and in the evenings. Big surprise.

The three uncontracted assets have to live off of RA. And since they are only capable of providing non-spinning reserve, they have to bid what they can supply, which is non-spinning reserve. If they're lucky enough to get awarded a non-spinning reserve award, they will get paid one cent per megawatt. That's 50 cents an hour, on a 50-megawatt peaker. That's $4,000 a year. That's a pretty low rent for a 50-megawatt peaker.

So, the problem statement is the sources of revenue, RA, and ancillary services are really providing very little to fixed assets that are uncontracted. And the number that was shown earlier, of $3.00 a kW a month, for RA, we think is an overstatement. That's probably at the higher end. At maybe some locations, some areas are getting it. We think it's an overstatement, we think it's considerably less.

So, what's to be done? Assets, like peakers, they're good assets. They're the right assets because peakers get out of the way of renewables. They don't have to motor along all night to stay warm, so they can be available for the ramp in the morning. They can be down all night and they can come up in the morning, just like ours do. But then they can go back down during the middle of the day.

So, the right gas peakers are the right kind of gas because they can get out of the way.

There's other resources that can be -- ways to enhance. We understand that with the loss of combined-cycle units, particularly the ones that motor through the night and are around, the CAISO is going to suffer a loss of primary frequency response. And that’s going to be a big deal. We also heard about in the presentation this morning, that the FRO is extremely important, and that near-term fix is to buy it from other BAs. But that’s not the long-term fix. The other fix is to find sources of primary frequency response within California.

Edison recently enhanced two of its peakers, at Grapeland and Center, by adding a battery and hybridized those units. Those units did not provide primary frequency response before, but now they do. And they’re also able to participate in spinning reserve markets, as well as high-speed regulation.

This is a good thing and we’re an advocate of this kind of technology, and we think that public policy should move to support deeper implementation of this kind of technology.

Other things that can be done. Cogentrix referred to improving or parsing better the method of flexible RA. We think that perhaps a new tier of high-speed, or get-out-the-way gas RA should be considered, so that there’s a -- instead of broadening the performance requirements, take the performance requirements that are really important for the future, and highlight those, and create a market for those. And peakers could be, maybe, the only resource, and maybe even ultimately storage. But create a market that highlights the things that are important for the future. Speed, flexibility, and getting out of the way of renewables.

Another idea that we have, and it would not take very much to implement, would be to re-look at the non-spinning reserve market, and how non-spinning reserve is accessed, how it's structured, so to speak.

And one idea, increase the procurement levels of non-spinning reserve, but give certain minimum wages, like create a minimum wage for certain assets that might be locationally advantaged. And it wouldn't necessarily have to be locationally advantaged for every minute of the day. They could be locationally advantaged for some minutes of the day.

But this way, a resource which is strategically located could access the real opportunity costs and opportunity value of that situation.

Okay. So, I think that's about all that we have to say about this, and look forward to the Q and A. Thank you.

MR. LITTLE: Good afternoon, I'm Eric Little from Southern California Edison. I have to start by stating that I will be touching upon the RA proceeding, which is open and active. And given that there is a

Commissioner here, and I believe there is still and advisor here, in the room, I will give you the opportunity, if you wish, to excuse yourself. Wow, that usually works with my kids, though. They run.

(Laughter.)

MR. LITTLE: They would be out the door already.

Okay, so that's fine. You heard about the problems --

COMMISSIONER RANDOLPH: Hold on one second. So, it's since we're noticed I think it's okay, right? Michelle and Rachel? Yeah.

MR. LITTLE: You heard a lot about the problem statement already. I'm going to go a bit more towards solutions, as well as another portion of the problem that Edison sees. And we've noted this for quite some time.

There's a few processes that we go through right now. There's a long-term process, that used to be the Long-Term Procurement Plan, now the IRP, that looks ten years forward, if not more, and decides upon what resources are needed and authorizes procurement for those resources, to ensure that they're there.

We have a one-year forward RA program that looks at the grid and says I need a certain amount of resources to be able to meet the load, and you saw this morning exactly how that's structure.

And, then, that has a must-offer obligation to those resources, so that they're available to the ISO.

What we're missing is something between those two points in time. And that's exactly the problem that's being described here, today, is you look forward five years from now and say, well, I don't have a contract five years from now. But if we looked at the condition of the grid in five years, you might want that resource there.

And if it's not under contract today, you've heard the risk from the folks sitting to the left of me, that they may need to take that resource and do something else with it, make some other productive use of that capital.

And, so, we're in that situation where you then say, well, okay, but if I let that go and next year, or two years from now I decide that I need it, don't have enough time to build a new resource.

And while there is new technology that's coming out for new types of resources, and a lot of those move us towards a carbon-free environment, and we're fully supportive of moving towards a carbon-free environment, we need to make sure that we have a good path to get us there, reliably.

So, we need to account for, in that five-year period, what resources are going to be needed in that time frame. And that leads us to a discussion, again in the RA framework, of a multi-year forward RA requirement.

And, so, before anybody says it, I already know, Edison has said, in this proceeding, we are not in favor of doing the multi-year RA requirement. I will tell you that it's because we are not in favor of a multi-year RA requirement, it's because of a timing issue. That timing issue is that we do not have a durable solution for the flexible product. We don't want to be looking at procuring something long term for three, four, five, six seven years, only to find out in two years that it doesn't actually meet the need of the grid. So, we're hoping that those two happen in concert with each other.

That said, a multi-year forward objective, to be able to deal with this issue, is a legitimate process. In that process, we think there's two ways to go about it and you need to do both of them. One is you may have something that is attribute based. I.e., I need a certain type of a resource that has the following attributes. But which resource, specifically, I don't really care, as long as you get them for me.

You set that up. Everybody who's a load-serving entity has a requirement to go procure their batch of it. They do so, and those resources are then procured.

You have a second batch which is more of a -- it may be an attribute, but it may be a specific resource that's needed because of a locational attribute, or something along those lines.

In those cases, we have mechanisms to deal with those, as well. We've dealt with them in the 10-year planning horizon, whereby the utilities are asked to go do that procurement. And in doing so, the utilities are given the opportunity to recover the cost for that from all benefitting customers. The mechanism is called CAM, the cost allocation mechanism.

As long as we have those mechanisms still available, and they can still be utilized to meet the reliability for everybody, because that is what we're talking about here, then you can meet that group of resources by doing a CAM process for them. And having the attribute base where it is, you know, any of the following types of resources be allocated to everybody.

And, of course, in the CAM process, when you do that it's all benefitting customers pay for it and everybody receives the benefit from it. So, to the extent that those resources are meeting a resource adequacy requirement, it lowers the resource adequacy requirement of all benefitting customers. I.e., the direct access providers, the CCA providers see their RA requirement go down because of the procurement that was done by the utilities, effectively on their behalf, for that process.

So, there is a mechanism to be able to do this procurement. There is a mechanism to be able to ensure those revenue streams.

You'll notice that in the local areas, particularly those that are heavily constrained, they need all of the resources to meet the need, there isn't nearly as much of a problem. And the reason there isn't nearly as much of a problem is because those resources know they're very, very likely to continue to get a contract. And that is something that is easier for them to go and finance, where something that they don't know year to year. A system resource, or being in a local area where there is many more resources than what's needed in that local area.

So, that's why I say if we do this, this dual process, we'll be able to have the ISO take a look at what resources are needed on the grid, define those that must stay, have a process to take care of those, define the attributes that must stay, have a process to take care of that. We have the resources that we need to operate the grid during that foreseeable future and we orderly transition to a low carbon future. Thank you.

MR. KRUGER: I'm Vic Kruger, from San Diego Gas & Electric, and I want to thank you for the opportunity to speak today. I'm going to keep my comments more specific to the unique characteristics of San Diego. We have many of the same problems that have been discussed already here, and will be discussed soon here.

But in the San Diego area, some of our unique characteristics are, unlike most of the IOUs in the Cal ISO area, we are impacted by actions in other balancing authorities, other than the Cal ISO. So, caution must be used because their actions could significantly alter the effectiveness of many of the possible responses of risk of retirements, possibly destroying their value.

Also, San Diego is mostly residential load. So, the upcoming mandatory time use rates, the electrification of transportation, the continued growth of rooftop solar PV, and behind-the-meter battery storage could mitigate some of the risk of retirements in the San Diego area because of our load profiles.

Also, the historical seven- to ten-year time frame needed to build generation or transmission projects may not be the limiting factor with certain retirements, because battery solutions may be able to cut this lead time, allowing more time to fully evaluate all possible reliability solutions before a decision must be made.

However, storage resources are energy limited, so long-duration reliability needs must be studied carefully.

And, finally, the more analysis that can be done before any firm decisions are made on economic retirements will result in the least cost/best fit solutions. Thank you.

MR. LAWLOR: Hi, I'm Joe Lawlor from Pacific Gas & Electric Company. Thank you for the opportunity to comment.

With me, today, is Jim Gill as well. I understand there were some hydro questions and Jim's here for that purpose.

I think we can all agree the economics of the market have changed. It has a strong impact on all generators.

The piece that probably we haven't talked about is the structure of the markets are changed. Load is shifting. PG&E has quite a few CCAs in its area. And something that often people don't realize, as Mark mentioned, I'm no longer necessarily a buyer. I'm a seller in many of these markets. And as more load continues to shift, PG&E's position will be more capacity sales.

When I look at, you know, what maybe needs to change, I personally consider the RA program very successful up to this point. But with all of these changes, I think it's time for some larger redesign efforts, and I've heard my other panelists say the same thing.

The one particular in PG&E's area, that needs to change, is the local other areas are bundled. When I was procuring for all the local needs in the other areas, and they were bundled, as the largest entity I could have a view as to where to place the procurement, to make sure that compliance was met, and to minimize CAISO backstop.

I think in an environment where there are many buyers, we have a real opportunity for different LSEs to buy, maybe in similar areas, resulting in even more backstop, more RMR than otherwise would have been necessary, had there been more centralized procurement.

And, so, I think we have to take on that bundling. If we unbundled it, at least the LSEs would have clarity as to where they had to procure in each area. And I heard earlier today that maybe that bundling was a result of market power mitigation and concept.

What I didn’t hear come up was the RA program actually has market power mitigation rules. And, so, those rules say, you know, if you can’t buy RA in an area, at $40 a kW, a year, and I know many of the other participants here helped design that program. So, if my numbers are a little off, feel free to correct. But you get a pass and then the obligation removes from you.

But the reliability still gets met, but CAISO steps in and procures, and it would procure on a cost basis. And, so, you do have a market power paradigm that exists there.

Another thing I would suggest that might need to be looked at as we go forward, as we consider all these changing paradigms, is maybe all of local needs to be centrally procured, by CAISO, by a State agency, by somebody. Because where’s the efficiency? Because it does feel like we are on the precipice of more CPM and more RMR, and I’m not sure that that’s the economic best outcome.

I will also say that, you know, longer-term RA. I hear that -- I know that that’s been a part of the market. WE saw the slides earlier.

PG&E hasn’t done an intermediate term RFO, which is a multi-year RFO for capacity, since 2014. We’re not going to have to buy again like that, that I can foresee in the future.

And, so, that's a piece of many generator surety that doesn't appear to be in the market anymore. I don't know what the contractors of other non-PG&E's are, but I hear that often from others. So, that's a piece that could be looked at, either RA or some other paradigm.

I think we also are in a situation where now we need to think about the CAISO procurement. I mean, I support the backstop, reliability is key. But it's not integrated into the RA program, because it was supposed to be a backstop and RA was supposed to be the front stop.

So, now, when we have RMRs coming in, is it coordinated in a way that it's not double procurement? And that's really another concern on net affordability.

The last piece I'll throw out. Really, the integrated resource planning process, I think it needs better integration with the RA paradigm, so that we can see how all the State goals are put together, how everybody's procurement comes together and assures that longer-term vision, and that separation has -- feels like that's going to be a part of something that needs solving. Thank you very much for your time.

MR. GOULD: Good afternoon. My name is Ross Gould. I'm the Director of Power Generation at the Sacramento Municipal Utility District.

I've got a slightly different perspective, as SMUD is a member of a balancing authority in Northern California and not ISO. We're somewhat of a vertically integrated utility. But we're still affected by all the same forces as everybody else. We're playing the same pool.

So, I manage a fleet of slightly more than 1,000 megawatts of natural gas-fired cogeneration and simple-cycle peaker plants. And I also manage a 700-megawatt hydro facility, up on the hill. So, I've got a little bit of perspective on both of those.

We've definitely seen a change in our missions. I've been here, just over two years ago, asking for permission to change my cogeneration facilities into more of a load-following facilities, by adding ox boilers, and stacked amperes and all kinds of things to change their mission.

We see the energy imbalance market coming to California and it's going to make a big change in the way that we operate our facilities. Hopefully, we're looking for the opportunity to get more usage out of our thermal fleets from that way.

We see storage as a big change in the game coming in the near future. And it's interesting to contemplate how that's going to affect us and how it's going to affect the entire market.

For now, though, we do really see a huge value in inertia. I heard that this morning. And it was like studied it, didn't really seem to make a difference, but I think it does. Especially in an area where we are kind of vertically integrated, we are a net importer of energy, and that's by design. And, so, we need to have that rotor spinning to be able to do the things that we need to do.

So, I look forward to providing a different perspective and thank you.

MS. JONES: Did you want to have questions now, or did you want to wait?

CHAIR WEISENMILLER: Actually, I was just going to ask one question for PG&E, just on the record. Obviously, we've heard a lot from the gas guys here but, obviously, the policy issue is sort of cost of operation vis-à-vis for price curves.

And so to the extent, so it's not just gas, I thought it would be useful for PG&E to talk about their hydro system, and what they're like at this point.

MR. GILL: Thank you. I think a lot of what you've heard here today is similar struggles that we're facing on the hydro side of the business. We have 26 FERC projects up and down the Sierras. And our biggest challenge is a combination of the changing energy market, the falling prices, the flexibility that's needed in the system. Much of our hydro system is flexible. However, some of it is not. Some of it is Gold Rush era run of the river, flume systems that don't have the ability to stop and start to meet the fluctuations that we're seeing as a result of rooftop solar, and larger commercial solar.

You add into that, also, the very complex relicensing process that we have to go through, not just at the Federal level, but also at the State level, here in California. The typical relicensing process can take anywhere from 10, upwards of 29 years to complete. And the conditions oftentimes result in reduced flexibility for our hydro fleet, a loss of generation, a percentage loss of generation, and many more ongoing mitigations and studies.

So, it's a complex sandwich, so to speak, of falling prices and escalating operative costs for our facilities that cause us to have to reevaluate where's the value in that for our ratepayers.

CHAIR WEISENMILLER: And you're recently

decided, at least on one facility, to turn back the license. Do you want to talk about that some?

MR. GILL: That's correct. So, our Centerville Project, which is just east of Chico on -- it's a combination of diversions from the west branch of the Feather River, as well as in Butte Creek. We had been under relicensing on that project since early 2004. We elected, approximately a month ago, to withdraw our application for renewal of the license.

And what that essentially means, we withdrew our application which, under a normal circumstance, would mean that FERC would then look for another potential buyer through the orphan process, or then surrender the project. And at that point, it would go through decommissioning.

However, FERC did something relatively new and they denied our withdrawal application, and allowed us the ability to refile in 60 days. And what that means is it gives us an opportunity to find a potential transferee to take over the project, as it stands under the current relicensing process, and they would carry it forward to get the new license. They have 60 days to do that. That 60-day deadline to express interest in the project expires this week.

It's our anticipation that if no one comes forward, expressing interest at that point, we would refile and FERC would then initiate the orphaned project process.

CHAIR WEISENMILLER: And, presumably, you have other projects that may end up in that situation. I've heard some, at least in the trade press, some speculation of Porterville?

MR. GILL: Well, I think speaking in terms of the entire portfolio, you know, given the changing environment that we're in, it's caused us to have to reevaluate all of our projects. We have some that are like the -- I'm assuming you're referring the Potter Valley Project. Such as the Potter Valley Project, where we are having to take a much harder look. Where some of the value in that project is really in the value of the water, itself, not so much in the generation, and what it serves to the broader community. So, there's tremendous value in it, but is it the right value for our ratepayers. That's the analysis that we're going through right now on every one of our projects.

CHAIR WEISENMILLER: And when do you anticipate having that comprehensive review done?

MR. GILL: It really all depends on the project, itself. But I would anticipate that within the next year we'll have a much firmer idea of where we stand in terms of our broader EOG portfolio.

CHAIR WEISENMILLER: And back many years ago, your system was like two-third pondage and about a third run of the river. My impression is it's closer now to flipped over, or what's your current split between run of the river and pondage?

MR. GILL: I don't have exact statistics, but not much of it has changed since that time period. Our Shasta System, which is up on the Pitt River System is a large, underground aquifer system that is -- does have some storage to it. Our Feather River system is completely run of the river.

You look at our Drum System, which makes up roughly 200 megawatts, is very much the flume Gold Rush era system that doesn't have very much flexibility to it.

CHAIR WEISENMILLER: Okay, thank you.

COMMISSIONER RANDOLPH: I have a question for Mr. Lawlor. You talked about doing centralized local capacity procurement. What do you envision that would look like?

MR. LAWLOR: I think it could resemble many things. It could be CAISO procuring through local areas. It could be a transmission PTO procuring for the local areas. I just really go to the, if we have very disaggregated load, how do we come up with the most efficient resource mix, with that challenge of the long-term reliability.

And when I step back from that, I don't know that what we're doing with the backstop and the bundled local areas will be the most efficient outcome. I think what's going to happen there is a lot of too much procurement in one local area, which then is complete compliance, and a lot of CAISO backstop.

And, so, I just look at how I've procured, when we were at the majority of load, to make sure that we hit all the areas. And the fact that the rules don't really line up with that objective today. And especially with, you know, a short-term program where resources would be procured different yearly, potentially, depending on how the future goes.

COMMISSIONER RANDOLPH: So, it's kind of one of the big fundamental questions is the sort of the system is really changing rapidly, in ways that we're trying to anticipate. Are there opportunities, that we're not considering, to sort of make the RA program, and the CAISO's backstop procurement work better together? Are there processes that we're not considering that might deal with some of these year-to-year uncertainties?

MR. SMITH: Commissioner, it's Mark Smith. Can

I help with that answer? I'm not sure that there are -- in terms of the local area requirements, yeah, things change around the edges. You know, as the ISO may build a new transmission project, as the ISO may redefine the local area for any variety of purposes. But the base requirements are fairly stable over time.

And, so, I think that what Mr. Lawlor is saying and certainly what I would say is the disaggregation of buyers creates transparency issues so that no one buyer is really certain that they've met all of the, not only greater Bay Area requirements for instance, but each sub-area's requirements.

And in doing so, you could meet the aggregate goal, but not meet the individual goals and, therefore, require backstop procurement.

And, so, I think, you know, what I would say is that what we should consider doing is enforcing all of those local sub-area and individual local area requirements.

CHAIR WEISENMILLER: My question for the utilities, has anyone done an intermediate procurement since 2014, or do you expect doing one every again? And, please, on the record and in the microphone.

(Laughter.)

MR. LAWLOR: PG&E's last procurement was in

2014. I don't anticipate a need to do anything besides short term, small, hourly, monthly procurement. Except for sales, which I do expect that we'll be doing more and more sales.

CHAIR WEISENMILLER: How about San Diego or Edison?

MR. KRUGER: I'm not directly involved, but I've been there for a number of years and I haven't noticed any intermediate term procurement, just our annual process the last few years.

CHAIR WEISENMILLER: Edison?

MR. LITTLE: For Edison, our structure of transactions has changed quite a bit. We used to do quite a bit of procurement that was all source. There's a lot of that procurement, now, that's moving over towards specific directives, such as RPS, such as battery storage, those types of things.

I do not know the specific answer to your question. I don't know how long it's been since we've done one. I know that since I've been there it's been a while for us to do a procurement of RA resources, and in multi-year forward fashion. And I do not know what the position looks like to where they will be doing that in the future.

So, I'm sorry that I don't know the answer to your question, but it has changed.

CHAIR WEISENMILLER: Well, it would be good, just in terms of -- when you get to your written comments, it would be to clarify. Obviously, at one stage you were doing long-term procurement out of the LTP, but that was only for new resources. And then you had under the bilateral some multi-- you know, less than five-year contracts. And, then, you have the annual RA.

It sounds like at this point, aside from some legacy bilateral contracts, the only thing in town is the RA. It would be good to clarify that on the record.

MR. LITTLE: I will check with our RA folks and we'll get it in written comments.

CHAIR WEISENMILLER: Okay.

VICE PRESIDENT DOUGHTY: So, an observation. In listening to Misters Smith and Theaker, some numbers that struck me. The progression of the shutdown of plants here. Brian, you mentioned 9,500 megawatts in '15, 8,500 in '16, and 7,000 this year, with a possible 2,600 remaining in 2020. That's a precipitous decline.

And I expect that Mark is seeing some of the challenges. And when we see numbers of that scope, going from 9,500 in '15, to 2,500 in '20, that's a significant indicator.

I don't know that I have a question based on that, just an acknowledgement of the scope of what you represented there.

MR. THEAKER: Tom, thanks. This is Brian Theaker. Yeah, we're well aware of the trend, and perhaps painfully aware of it. But, you know, I think those numbers represent -- the '20 number obviously represents a view of the future.

But given the changing nature of the fleet, especially the OTC retirements, a number of commenters have made the point that right now we have an issue with flex characteristics, because we have a lot of long-start units that provide a lot of flex. I think that's a self-correcting problem. I think when the steam turbines go away as a result of the implementation of the once-through cooled policy, that problem will have been solved.

So, I'm not yet persuaded that we need to do something special. I think that's a natural process of attrition that's going to happen. But I'll confirm your numbers or your perception to the numbers. It's a significant drop.

MR. SMITH: Thanks, Tom. It's Mark Smith with Calpine. I don't have numbers like that to predict. But this, I will say, that most of our resources are all built in the same time frame. They're based on largely the same technology. They all face exactly the same marginal costs, and most of them need uplift right now, those that aren't on long-term contracts.

So, but for local reliability needs, and some alternative form of contracting, probably an administrative vehicle at this point, you know, it may be unfair to count on those resources being available, you know, beyond the near term.

VICE PRESIDENT DOUGHTY: And for us, looking at 2017, 2020 and beyond, one of the things that becomes most challenging is the scope of the ramp. Right, we're looking at ramps, now, of 10,000 maybe 13,000 megawatts. And into 2030, it wouldn't be out of the question to see ramps of 20,000 megawatts.

So, when I start talking with you guys about numbers of this scope, units that we'd be calling on for that ramp support, that's where the concerns begin to become real.

MR. BLUE: Just kind of a follow up to my colleagues down to my right here. The issue of do you have to do anything with the long-start generation that CAISO reflects, that it will naturally take care of itself, I guess when you say that on one hand, and yet on the other hand you're extending the same plants beyond their OTC dates it's kind of a conflict there.

And people right now are in a situation where they can't wait two or three years for this to happen, in 2020. And, so, the question is what do you do in this short-term period, between now and let's say three to five years, when you have the OTC plants leaving, you've got the energy storage balance, you know, market coming up to scale. You've got the cost allocation issues, which are a huge issue to the utilities, how they're going to do that going forward. You've got a lot of things to resolve.

And if we want to wait until we get all that resolved and then implement, you are going to have generation retirements and those are going to affect, as I said earlier, your forward -- all three of you are doing long-term forecasting and you're including available capacity that could just meet -- we saw this morning that they're short, already, starting in 2018, but they have plenty of available capacity there to close the gap, uncontracted.

That's going to drastically change. So, I'm just saying, I agree, it is going to take care of itself. Can we wait that long is the question? Some of us can't.

MR. THEAKER: Yeah, Tom is Brian Theaker, if I can follow up. I agree with everything Greg said. And

I would also, probably offer that maybe a conversation around flexible characteristics is akin to a conversation around the order of the deck chairs on the Titanic. Because at present the system is so long in that attribute that it has no incremental value.

And we're also waiting for first numbers from the ISO on the performance of their new spot market product, the flexible ramping product. But again, the predecessor product that the ISO had implemented, by the time that product had matured, it was throwing off a very di minimis amount of cash, something on the range of $10 million a year, to fleet wide.

And so, we do have this transition period where the attribute is important, but we are still long in it to the point that it's not important enough, it's not valued enough to make a difference in the revenue adequacy for these resources.

CHAIR WEISENMILLER: Yeah, for long. But, you know, the bottom line is we need some plants to retire. You know, sort of particularly some of the older plants need to retire, particularly in some of the areas where we have excess capacity.

COMMISSIONER RANDOLPH: I have a question for Mr. Little. We -- you were talking earlier that SCE's position is at this point in the RA proceeding is not requesting multi-year, but sort of it's a goal in the future. Kind of what do you see as the kind of conditions precedent that you would want to see happen before your company feels comfortable saying, yes, that's something we're interested in?

MR. LITTLE: Oh, thank you, good question. I think there's a couple of things. One is having a stable rule set around what is going to count for resource adequacy. So, the big changing point right now seems to be flexibility. Right. Is it going to remain a three-hour product, is it going to be something else? That's a significant issue.

If we were to have a multi-year forward program right now, and buy a resource that counts as a system resource and a flexible resource under the current rules, and we buy it for five years forward, and find out in a year that it no longer does, now the question is, well, we may not have enough room in our portfolio for another just generic system resource for five years forward, and now we're buying something else at the cost of ratepayers.

So, having some stability around those sets of rules is important. And I think the second piece is the cost allocation that I mentioned earlier, of ensuring that we have a reasonable cost allocation methodology to ensure that if a resource is being bought by an entity, for the benefit of all customers, that it's being paid for by all of those customers.

And we have that mechanism. As you well know, it's a rather controversial mechanism, and there's always a lot of talk about it.

So, you know, Edison does not object to procuring resources for those types of benefits, provided that they are paid for by all of the customers that benefit.

So, I think those two pieces are really the most critical.

MR. KRUGER: This is Vic Kruger, from San Diego Gas & Electric. I'd like to support Eric's statements on that.

And one further point about these rule changes. Just as an example, right now we're looking at unbundling the local attribute from the system attribute, for RA showings and things like this. It may seem like a minor thing, but this uncertainty makes it very difficult to go into a multi-year RA process, when you don't know what you're going to contract for, what you're going to need to show. Can a locational attribute for a generator be split up, such that it's no longer local, even though it's in the local area? And is it meeting the needs for that area?

So, a lot of these details have to be ironed out before you can really, fully support going out long term and taking the risk of contracting this out several years, when you know maybe the attributes will change such that you're going to have to change your portfolio, and have extra cost to make you've got the then-current attributes covered.

MS. JONES: So, there were a number of questions that came to mind. In particular, I wanted to ask Mark why do you continue to generate?

(Laughter.)

MR. SMITH: Well, like it or not, I signed a participating generator agreement. And, therefore, I really have no choice in this market. You know, that's the fundamental reason.

But you're right, it's an honest question. Why in the world would somebody continue to operate a generator when the best outcome that you have is to recover your variable costs. You get virtually no contribution to either a return to, or a return of your stakeholders -- or shareholders' investments.

You know, we're in the local reliability areas. We know our role and we're not out for the societal good. We're a profit-making entity. But we understand that our units are critically needed for the reliability of the grid.

We'd much rather solve this problem than create any kind of Brinksmanship.

MR. BLUE: So, a quick follow up. One thing slightly different from a peaker plant point of view, versus a larger plant, the larger plant really can't be picked up and moved. They're kind of here.

The smaller plants, they are derivative turbines. They actually can be located. And the exact plants that you actually do need are the easiest ones to be relocated.

MR. THEAKER: Thank you. And sorry to the folks on the phone, who have to listen to the sound of the microphone being passed. This is Brian Theaker, with NRG.

I wanted to respond to the question you posed to Mark. It's a difficult question. Questions around the timing of power plant retirement are very difficult because you're talking about long-lived assets, that have community relationships, that have staffs. They're not questions that are faced cavalierly. They're difficult decisions that are emotional and, you know, are tough to make.

The question, why do plants continue to run when the economics would suggest otherwise? I think some of that is, you know, hanging around, waiting for the fundamentals to change, for the system to get tighter. For, you know, flex to have some value, I think that's part of it.

You know, I think that the uncertainty around where this is all headed is part of it as well. Is, you know, you don't want to -- if there's a party coming, we don't want to miss it. So, it's a complex decision that's not considered lightly. And retirement decisions are tough to make. I think that adds to the angst of why are we over in supply.

MR. SMITH: Piling on, I guess, this is Mark Smith again, with Calpine.

Piling on to that and transitioning to what we might like to see in the future. These decisions are very tough and it requires a pretty long runway to be able to understand the need for a unit, and what steps need to be taken to execute that retirement.

Or, in order to execute a plan for continued operation, if the plan is otherwise uneconomic, but the ISO is going to deem it to be needed.

And, so, one of the things that gets in our way is the current RA contracting process. And as Tom indicated earlier, the fact that that process initially completes itself in maybe October of every year, but then it goes to the ISO for another month or two, with deficiency analysis and deficiency reviews. So, it's very, very possible that a resource that is, you know, in question about retirement will be forced to continue to operate until the last week in December -- that's an exaggeration. Maybe early December. Not knowing whether it's going to be needed January 1st.

So, in order to provide a runway for people to make decisions on retirement, Calpine would like to see a much more advanced review of reliability needs. Which then, going to someone else's point earlier, could then fit into, maybe, the RA mechanism, so that resource was already known to be acquired or purchased by the ISO.

MR. CUMMINS: So, why would a resource like a peaker continue to stay around when it's just barely making enough money to keep the doors open, or not even keeping the doors open?

There's, depending upon where you are, there's a huge value to an existing and viable interconnection. And the cluster process has a very long duration for the interconnection of new resources. So, people that have existing assets, with existing interconnections, they've already gone through a lot of the barriers to entry of new megawatts.

So, where you have a peaker, you could redeploy that connection, that interconnection with a new technology, or an updated technology. So, if you're able to pay the bills and keep the business alive, and you should, then you may have economically efficient repowerings with storage or enhanced gas turbines.

MS. JONES: Great. Thank you. So, some of what I've heard is that we're looking at an issue that might be a three to five year issue, and there might be some dispute on that.

Having been around in this business for a long time, this seems to keep recurring, and we seem to keep -- every, you know, few years we get into a situation where we're relying on reserve margins, but we don't have resources locked in for a midterm.

Do you think that there's an ongoing need for a product that's three to five years, or a process that is? Or, do you think that the changes are such that that's not going to be an issue in the future?

MR. LITTLE: This is Eric Little, from Edison. I'll give it a shot. In the immediate future, you might get out of the problem as you start to move towards more and more RPS types of resources, more and more battery storage types of resources. Where, to get those resources built you are signing ten-year contracts, plus.

And, then, once you have those all operating, and if the need of the system is not changing, there won't be additional resources that are needed. They're all funded because they have a multiple-year contract.

But, eventually, those start to come off contract again, right? And it's the same problem here. We experience it with gas resources. We do -- like, back in the day it was LTTP, now it's integrated resource planning. You do that ten-year deal, and once that ten-year deal is over, now that resource is out there in the market and it doesn't have any sort of a multi-year requirement to go along with it.

So, can you make that problem disappear in the short term? Quite possibly, through these longer-term solicitations that we're doing for other purposes. Will it recur? Most likely, as you stop doing those long-term procurements.

MR. BLUE: Yeah, I think they're -- as I stated earlier, we believe there is a need for a three to five year product, or at least a multiple year product. And, of course, we think it needs to be now.

Part of the reason is that these plants have different types of maintenance. They've got your regular maintenance, then you have long-term maintenance. Longer-term maintenance are replacement and/or even upgrade to the facility to help it have other characteristics.

These are types of things that you aren't able to recover in a one-year contract. So, you come up to where you have to do a major maintenance. And the reason that's all important is because the existing contract, existing power plants have a much different power plants have a much different cost structure than new build. And if you lose the existing plants, you're going to be stuck with new build. The time and the cost going forward with that.

So, we think -- we, as I said before, I believe that there should be some sort of a three to five year program. We look at it as an insurance policy for reliability, while you're sorting out all of these other issues that everybody's talking about.

MR. SMITH: And let me add just sort of a related point here. That in some of the other markets there's a three or four price signal. You know, it's a capacity market in many of those years.

And that three or four price signal and award gives you transparency in terms of the need of your resource. It allows you to make reasoned decision making between now and the three-year time cycle.

Or, on the other hand, if you are not awarded one of those capacity contracts, or in the analogy here in this case, a contract with an LSE or an SCCA, you're allowed to take the steps that you need in order to manage your -- reasonably manage your removal or de-listing from the market.

I think, therefore, that it makes a lot of sense. In the East they've been, I think most people would say, highly successful in managing the over-capacity situation and reductions that have occurred, as the secular change there moved from coal to gas. And many, many coal-fired plants have been shut down, to the benefit of many folks.

It's not an uncommon situation and it shouldn't be new to us that those kinds of forward price signals are what's needed in order for people to make rational business decisions, in terms of ongoing operation.

MR. THEAKER: Thanks, Melissa. Brian Theaker with NRG. Not to turn this into a Howard Johnson as a right moment, but I will. I agree completely with Eric. He pointed out, clearly, that we've kind of got a blind spot between the one-year RA look ahead, and the 10-year LTPP. And I think something in the middle, we've talked about it for a long time and haven't done much about it, I think it's important to cover that blind spot.

And I also agree with Greg. Generating units have lumpy revenue requirements associated with major maintenance. And I think that's absolutely a reason why a one-year cliff doesn't get you to the kind of rational and meaningful decisions. You know, you need a longer runway.

MR. LITTLE: Just one more thing, real quickly, just to make sure that it's clear. When I was talking about you might be able to get rid of the problem temporarily, with the long term, I also don't think that having an intermediate term ends up becoming duplicative, necessarily. You won't end up procuring twice the number of resources.

If I've got a five-year forward requirement that says I need to procure 20,000 megawatts, just as an example, and I've got a ten-year forward requirement that says you need to procure 4,000. That 4,000 is going to count towards that interim term, 20,000 megawatts, as well. It's not that I have to just ignore that and go buy more resources. So, we're not talking about the potential of over-procurement here. How these things would count, and that needs to be there.

But if what we're trying to address is, you know, I don't need the resource this year, necessarily, but I do need it in three, four or five years, and if I don't do anything about it now, the resources may not be there in three, four, five years, then that program should be addressed. And, again, it does not run into conflict with the long-term program.

MS. JONES: Thank you. So, we've talked some about time frames, and some people have mentioned needing different products. How do you see offering different products, including some of the ancillary services, as contributing to your ability to stick around?

MR. BLUE: Well, we have the capability of making upgrades to our plants, too, so we could offering spinning reserves, for example. But we can't make that upgrade with a one-year contract.

MR. THEAKER: Melissa, this is Brian Theaker with NRG. It's a great philosophical question. I think it's one that I perceive that we've largely answered as State policy.

You know, California made the decision, and I agree, with the highly successful implementation of the RA program, that we were not going to trust the reliability of the needs of the State to the spot market resources.

You know, we've got folks within NRG who are on both sides of that academic question. You know, if a spot market, with very high price caps is the right structure, or whether long-term forward, you know, capacity contracting is the right structure. So, I won't try to settle that debate.

But I think the reality is that if you look at the ISO's ancillary services markets, I think for 2016 -- well, I don't know the 2016 numbers, the report hasn't come out. I think the total value in that market for 2015 was about $50 million, which is not very much value.

And that's a trend that we have seen for the last ten years. It was a lot higher than that in the early 2000s and, of course, across the energy crisis. But there just isn't the kind of monetary inertia in the spot market that would sustain resources.

The question that Melissa asked, and I think she was looking at me, was do I think they're priced properly? Well, I think we have a fundamental problem at this point. Commissioner Weisenmiller, you know, acknowledge we're very long. And, so, we don't have the kind of supply/demand equilibrium that would bring prices to the levels that would be meaningful.

I think it's primarily a fundamental issue with supply, as opposed to a price design issue at this point.

MR. LITTLE: Melissa, can I comment on that? So, I think I'd like for us to think about this a little bit differently. Energy markets and ancillary service markets are operational markets. And, typically, what we see there in prices is the marginal cost to provide an increment of energy.

And ancillary services, a lot of times what we're really talking about is the opportunity cost. What could I have done with that resource, had I not provided the capacity associated with it to provide energy, if it's needed at some other point in time. And there's an opportunity cost of doing that.

That, competitively, is how those things get prices. And I think what we've heard here, today, is that the way that the market ends up clearing, you don't get enough money out of that to be able to make the upgrades necessary to a facility over a longer period of time to keep it economic.

So, while you're meeting your short-run marginal cost, it's really much more about the medium- to long-term marginal cost that's not being recovered. And that's where some idea of a capacity payment comes in. And that's where we say, okay, well, a one-year forward RA program, which is a capacity payment, is not enough of a guarantee for somebody to continue to be able to invest in that plant, hence the multi-year.

So, I guess from Edison's stand point, I don't think it's an ancillary services issue. If the ISO has the sufficient resources to be able to provide ancillary services, and they're operating that in the market, we're fine.

If the ISO, on the other hand, is saying you know what, there's not enough resources on the grid that can provide ancillary services, then we have a different issue. But I'm not hearing that there's not enough resources around that can actually provide the ancillary services.

MS. JONES: We talked mainly about -- oh, go ahead.

COMMISSIONER RANDOLPH: I have a question. So, if there were multi-year RA, given the current supply that's out there, is the market going to support that? Is it going to be profitable enough to have the result that you want?

MR. BLUE: We think so. If the alternative is a one-year contract or no contract, yes. I mean, I don't know if that's a good enough answer but --

CHAIR WEISENMILLER: Yeah, but again, if you think about the eastern capacity markets, if you go above a certain level, the value capacity's zero. We're certainly above the level of reserves were the answer would be zero, if we had a market for that.

So, again, it’s not necessarily the question of whether, say, we have a capacity market or not, you know, we have excess capacity. Until you get the excess capacity down, the answer’s going to be zero.

MR. SMITH: It’s Mark Smith with Calpine. I don’t think this is the first time you’ve heard this from Calpine. We do think the market is a bust. We’re not convinced at all that a multi-year contract, especially if it’s only for a portion of the LSE’s need, which is probably already going to be covered by utility-owned generation, is going to create a price signal that’s going to be sufficient for us to continue operations.

That’s one of the reasons why, in addition to offering prices for our peakers, that we thought were reasonably compensatory, and having those rejected, we finally turned to the ISO and said, these units are going away, unless something else -- unless you find a reliability need and designate them as RMR.

So, Commissioner, I would like to be optimistic and say a three to five year contract, alone, might solve my problem. But I believe administrative solutions to this market, quote/unquote market, might end up being the rule of the day. I'll leave it at that, at this point.

MR. CUMMINS: Yes, I'd like to offer an idea. I think that the idea of the three to five year contract, if you're talking about for all sources of RA, all types of facilities, I don't think that that's what we're trying to get at.

I think what we're trying to get at here is that there's an asset class of assets that are unique in their ability to get out of the way of renewables, and be there very fast when you want them. And targeted -- targeted three to five year contracts that give you what you need, the quick shot in the arm, that's what I think we're talking about.

I think, so, it's probably creating a new tier of RA that presently doesn't exist. The RA that exists today is sufficiently broad that it sweeps a lot of different asset classes together, and creates a different market dynamic than if you were to look at this from an asset class perspective.

The other thing that I wanted to get at was, in answer to your question about the ancillary services, and I had suggested in my opening comments that for certain assets a minimum wage approach might be applicable.

Now, my colleague to my right suggested that when bidders are bidding, they're bidding essentially their opportunity cost. But a minimum wage gets at the opportunity cost of the CAISO for those assets to be around or to keep those assets around.

So, we have two players in the market. A bunch of people that are bidding and one buyer. Each of them as an opportunity cost and they're different. So, we're talking about maybe a switch of emphasis from the opportunity cost of a larger group to what the real opportunity cost is to the CAISO.

MR. THEAKER: Yeah, thanks, Brian Theaker, NRG. I'll follow up. You know, clear, I think we all understand that multi-year forward contracting is available, now. The utilities, by and large, have the discretion to do that. The question is do they always contract with the right resources? Sometimes they don't, because they probably don't know what the resource, the right resources are. Because, again, we've got that blind spot between one-year RA and ten-year LTTP.

You know, I think our conversation around how do we discern what the right resources are is going to be a fascinating conversation. And I think I tend to agree with Mark that answering that question is going to take us more towards an administrative price, than a market, per se. Because at that point you're going to identify resources that you need. That raises the specter of market power. And, you know, so bilateral pricing at that point may or may not be possible.

But I do believe that this vehicle is what we need. I think the pricing will follow once we get the process design in place. And I think that we still have a fair amount of work to get the process design.

Because answering the question what are the right resources is not a trivial or simple matter.

MS. JONES: So, to get a little bit more at the missing money issue. Are there services or attributes of your generators that don't have formal products, that would be helpful for you?

MR. THEAKER: Thanks, Melissa. Brian Theaker. You correctly discerned that I can't stand awkward silence, less than any of my panelists.

I will point out one particular attribute that I think we need to think more about its value, and that's duration. I think that, for example, NRG is very bullish on energy storage. We think energy storage has the potential to be a really important and critical piece of solving the issue of the duck belly, and what to do about that.

But we’re not yet persuaded that energy storage, even four-hour storage, in and of itself, is always the right fit for a reliability situation, where you’ve got a transmission constrained area, where you may not be able to -- I mean, the duck curve problem is an issue of a diurnal pattern where it’s relatively easy to figure out when to charge and discharge the device.

Applying energy storage to a local area reliability need I think is a different -- well, a bird of a different feather, if I can use a bad analogy.

So, there isn’t a product that values duration, but I think it’s an important service that we need to bring into the conversation around, that we’re having now, about what assets do we think we need to keep.

MS. JONES: So, we’ve heard quite a bit from the generators and from utility, but from the other utilities’ perspective, how do you see the needs?

MR. KRUGER: This is Vic Kruger from San Diego Gas & Electric. On that last question, we’ve seen the Cal ISO institute some products in the last few years, you know, mileage on regulation, and other things. I really don’t want to see another product created that’s going to be an over-supply, because we haven’t had any retirements, and it’s got zero value, and it really hasn’t solved the problem. And may even make the problem worse because it gives a signal to the market that this is worthless, so too much exists. And then, all of the sudden, the other stable price is infinity if you've got too little of a product, and there's zero if you've got too much of it.

So, I think it's a timing issue. And I think this whole forum is trying to create a roadmap to get to a stable, new equilibrium. We know we're out of sync right now, but how do we get to that new, stable equilibrium that we think we need in 2020, or 2025, or whatever it happens to be, and work towards that.

MR. LAWLOR: Joe Lawlor, PG&E. So, similar to Vic's comments, I don't necessarily see new products being the solution. But what we have is if I used a flex product, for example. Just a very product, three hours. So, if we really need some fast flexibility, we've created a very broad product. And the result is, incrementally, it's not worth much. That's kind of what I'm hearing. And I tend to agree with that.

So, if there are necessary products, we might need to tighten them up so that they create the value. The market is long in many places. So, there is some, hopefully, orderly retirement that happens.

But I think, and then I go to personal opinion, then how do you get to the market and regulatory mechanisms to create the right retirees versus the right ones to keep? And that becomes tougher with things like bundled other areas. And a very diverse procurement structure.

And that's to where I to go maybe the Eastern markets have a little bit of an easier time looking at and balancing all the constraints, and putting out some multi-year signals to help the whole market move in the right way. But I'm sure there's other ways to do it.

But that's really where I'd go. I wouldn't necessarily go looking to add another product on. But you might need to review the products we've got and the conditions behind them to make sure they're as tight as we need them to be.

MS. JONES: Okay, great. Thanks. And just a follow-up question. If you were king, how would you determine which plants need to stay and which plants need to go?

MR. LAWLOR: So, King Tom.

(Laughter.)

MR. LAWLOR: I got to go to, you know, who has the best view of all the contingencies, and all the plants, and the economics of them? Somebody needs to help with that answer. And I do think that this becomes more challenging, like I say, as different people procure. Because I used to have a whole lot more information to make tradeoffs.

You know, the local reports that they put out have efficiency factors, right? So, I would know, if I had a very large portfolio, which units I've procured in different areas, and which efficiency factors, and could come up with some assumption as to what backstop might or might not look like.

And I just go to, as we have many people procuring, which is a direction, you know, that I'm in support of. But as we do it, do we need to have these changes in the markets to say, well, how do we get that efficiency back? And it might be that somebody who has that larger view and can balance this stuff could help with how to select that.

Right now, I think I heard somebody say, you know, when CAISO -- when IOUs do it, we know when IOUs do something, we have an independent evaluator and we respond to lower prices, although we could consider these other things. I think, going forward, we don't have that view and so you move even farther away from what we could consider. That's if I was a buyer. I'm a seller.

MR. LITTLE: And this is exactly what I was talking about in my opening few minutes is that we have a -- Commissioner Weisenmiller hit it right on. We've got resources that are unnecessary. We also have resources that are very much necessary.

The problem is the current mechanisms don't decide which ones are necessary and which ones are not. We don't do that, expect for the ten-year forward process. On the yearly process, we simply say there's an amount of quantity, go get this.

What we really need is what I had mentioned earlier which is, look, there's a certain set of attributes that I need, and I'll give a more specific example. Flexibility, so far, has been stated by the ISO to be a system need. So, I can use any resource, as long as it's flexible, as long as it can meet this ramp and there's criteria for doing that.

That's the type of thing that you can say here's the quantity, the market, go get it for me.

There's other resources, for example local. I know that Michele had her chart up there that showed the local requirement and the local resources, and there's one in there where the local resource is actually fewer megawatts than what they need.

And, so, in those situations there's an obvious answer. Well, I need those resources, specifically. And, so, that's the category where, then, the ISO can identify, no, I've got a specific resource that's needed for the following transmission system contingencies. that needs to be procured, and that's the type of situation where instead of saying, market, go get this for me, because it's hard for, I think Michele also said, 25 load-serving entities. It's hard for 26 load-serving entities to go do a contract with one resource.

So, that's a situation in which you say, okay, the utility then is going to go procure that resource and cost allocate that resource. That way you have the correct resources, the ones that are needed for local reliability. You have the correct resources for ramping. You procure them in different manners, but you ensure that they're there.

Whatever's not covered by that, presumably, then, is the set of resources that is in excess of what you need, and those can retire.

MR. THEAKER: Brian Theaker. Melissa, this is the simplest question you asked all day, but I think that the answer that I would give you, if I were king, what resources would I keep, would be a little different on behalf of NRG's shareholders, that it would be for Mark's answer, on behalf of Calpine's shareholders.

So, having said that, I'll dovetail what both Joe and Eric said. I think this is going to have to be a multi-faceted look. And I know that in terms -- that LCBF is kind of a four-letter acronym, and our experience with LCBF hasn't always been the shining example on the hill. But I think it's that kind of look, is to look at resources that don't just meet one narrow need of the system, but can be applied across a spectrum of needs to meet local requirements to meet flex, to meet a bunch of things.

And then, you know, I'm just making this up, then maybe you'll end up with some kind of graduated scoring across these categories that leads you to some idea of what we think the right, and I'm using your quotes here, resources are.

MR. BLUE: Greg Blue, with Cogentrix. If my plants are not needed, I would rather know sooner, rather than later. So, I'm concurring with what I heard today. I mean, I'm told that our type of technology is needed. But if it's not needed, if a specific plant is not needed, I would rather know sooner, rather than waiting until the end of the year, on an annual basis, to figure out if we're going to live the following year or not. So, I concur with that.

MS. JONES: So, this morning there was mention of the ISO's long-term economic outage, and it looks like it bridges the gap between six months and a year.

How do you react to that? How valuable is that?

MR. THEAKER: So, Melissa, Brian Theaker with NRG. I'll give you our take on this issue because I think we were the ones that raised in the -- this was in the La Paloma filing a couple years ago.

Our point to this was if the resource is not encumbered by RA, if it's not got some kind of forward contracting, that resource should be able to take any kind of outage, any time it wants, without penalty.

And the ISO's tariff, I mean the ISO's got this handcuff's on. It's not the ISO's fault. But the ISO does not recognize that kind of outage. If you're a participating generator with the ISO, I can go request an outage from Tom, from a number of categories, but economics is not one of them.

And, so, we just -- and the ISO has committed to reevaluating this. They're going to launch a stakeholder process this year. So, we're looking forward to that conversation. But we think it's as simple as what's the ISO's role in approving an outage for a non-contracted unit? We think it has no role, but they should be able to take it.

Well, I don't want to prejudge how the stakeholder process will come out.

MS. JONES: So, how long of an outage could generators live with, or would they like? Is it more than a year out, or six months out?

MR. THEAKER: I don't know the precise answer. I think it may be putting in some kind of condition, until -- you know, at a minimal cost until the market turns, if it does turn? There isn't any way -- I can't give you a precise answer to that question, Melissa.

MS. JONES: Go ahead, did you want to say something?

Let's see, we've talked some about mechanisms already. So, do we think that the full diversity of performance is being provided for in the suite of generators we have, overall? Or, are there some attributes that just don't get counted for anything that should count?

MR. THEAKER: So, this is Brian Theaker with NRG, who can't stand awkward silence, again. I think the issue is how are the attributes valued. And, clearly, we've heard that because of over-supply there is no intrinsic value to flex. That situation will, hopefully, change.

Because flex, I think, the ISO has appropriately, you know, noted the need to transition from capacity to capability. And I think we're on that road, but there's a lot of road that we've got to get to before we hit pavement, and that's just because we're so long at this point.

Again, I think there's some attributes that maybe are not extrinsically or intrinsically valued, like duration, that we can't leave out of this conversation.

I think, you know, availability, dispatchability, duration, you know, are key reliability attributes that have to be factored into this conversation. And if we can find ways to value them, great. If we can't find ways to value them, we can't forget about them.

MS. JONES: So, sort of a different kind of a question. Oh, go ahead.

MR. THEAKER: I hoped that I answered the right question.

MS. JONES: Yeah, that was good.

In terms of reliability, with the system changing as much as it has changed, and will change, is the sort of reliability metric that we're currently using, the 1-in-10 years, is that still a valid concept or do we need to change the way we think about reliability?

MR. SMITH: It's Mark Smith, with Calpine. The 1-in-10 years is applied to determine local reliability area requirements. It's a stressed system condition that seems to match very well to the other stresses that are being applied to the system in order to determine the minimum amount of generation that's needed.

So, in other words, you can have a load pocket. That load pocket can only import so much energy across the transmission system, as it's designed today, or will be designed during the study period.

Anything, any load above that transmission import level essentially needs to be local generation. So, I think it's absolutely appropriate that you want to look at highly stressed conditions for that circumstances. Otherwise, you suffer load of loss -- or loss of load, which I don't think often we want to have happen. Thank you.

MR. THEAKER: Melissa, Brian Theaker. I think the 1-in-10 LOLE is still a very important metric.

You know, we've taken steps this past year to make that metric more meaningful. The PUC has taken a look and Calpine has done some really good work in terms of the RA capability of variable resources to try to make that 1-in-10 year loss of load expectation make sense.

So, I think it's still an effective standard we ought to retain. But I think there are other aspects of the changing nature of the system ramp duration that are metrics that have to be brought into the conversation. The 1-in-10 is important, but it's not the be all, end all statistic for reliability.

VICE PRESIDENT DOUGHTY: And, Melissa, just to add, those a NERC and WECC requirements. Those aren't things that we could modify unilaterally, so there's an acknowledgement there.

MS. JONES: San Diego?

MR. KRUGER: Vic Kruger, San Diego Gas & Electric. I think you have to couple that with some of the other reliability criteria, not just the 1-in-10. I've worked at other ISOs around the country, in my career, and loss of load probability or loss of load expectation, and things like that.

When you get to some of the Cal ISO standards that are above and beyond what NERC and WECC have with the G1N1, or the N1N1, you have to balance those against other, you know, state goals as well. Whether it's once-through cooling or other criteria. So, you have to have a stress system and I agree, you want that for reliability. But I think the CPUC has to decide what they're willing to pay for. You know, how stressed of a system and at what cost.

Michele had on hers, you know, she has to balance the cost against the reliability. And it may need to be looked again, just to see if we're consistent with the serving loads, and things like that, that we're using the appropriate reliability criteria in all cases here.

MR. THEAKER: And, Vic, Brian Theaker, I agree. And I think that, you know, the acknowledged part of where we still need to do a lot of homework in IRP is we started the conversation around the meaning and validating those metrics, but we haven't finished.

MS. JONES: So, I had a question about the role of the gas plants in the long run. So, we have a tradeoff between keeping reliability. We have some additional resources we'd like to develop. How long are we going to need to rely on these gas plants?

Go ahead.

MR. KRUGER: This is Vic Kruger from San Diego Gas & Electric. I think gas is an important part of the portfolio. Some people think you can just put enough batteries out there, and enough renewables and you have a perfectly good system. And I think we've already seen some diminishing returns on certain gas plants.

But it makes sense because batteries have a duration aspect. And, certainly, the contingencies, especially in small areas like San Diego, and Brian brought this up, sometimes the contingencies can't be readjusted for within the four hours of the batteries, or even six hours, or two hours, or whatever your standard is.

So, I think you have to have that as a backstop, where you can bring on this longer-term unit. And someone brought up that, you know, gas is a wonderful storage medium because you have it there and you could run this gas plant as long as you needed to maintain the reliability.

Whereas some of these demand response, and batteries and stuff, you have to design for something and you can't design for it at all times.

MS. JONES: So, how do we weigh tradeoffs like running the -- needing the gas plants for reliability and GHG reduction?

MR. THEAKER: Melissa, Brian Theaker. I think that's part of the, you know, the LCBF kind of set of glasses that we need to look this through. I think there are absolutely tradeoffs, and it's important that we squeeze all of the carbon out of the electric supply. But we're going to have to squeeze all the carbon out of every sector.

And I think, again, transportation electrification is -- we're putting a lot of eggs in that basket. But that basket doesn't -- you know, if there's holes in that basket, if we don't have reliable electric supply, then we've probably taken on a fool's errand.

So, I think it's just a set of tradeoffs that you're going to have to bear in mind. I think ROP will, you know, constantly be revisiting that question of, as we adjust the GHG targets down.

But, you know, when you're having conversations about reliability metrics is when those two things, in an LCBF kind of framework, and trying to come up with the right decision.

MS. JONES: Yes, Ross.

MR. GOULD: Yeah, so we're right in the middle of our IRP, and we're going out to 2030, 2035, and we don't see any decrease in the need for our thermal fleet. We're viable all the way through the end of the planning period and on.

It's definitely a balancing act with the greenhouse gas requirements and trying to figure out -- and the value of the thermal plants is just what we've been hearing here. You turn them on and you can leave them on for as long as you need them. So, when that need arises, you know, it's almost like the EV cars, you know, there's distance anxiety. You don't have that with a thermal plant. You can just turn it on and run it.

So, were able to maintain that because they're ours, and we own them, so the sunk cost is sunk. And I've become very innovative in trying to figure out ways to reduce the ongoing variable costs involved with them.

But if I was on the other side of the table, it would be very difficult for me to hold open a power plant that we built in 1987, that runs maybe 50 hours a year. I can only do it because I've already paid it off and I don't have to pay anybody else for it. And I've got an operating contractor that can do it remotely.

So, you know, I'm able to maintain the costs in that way. But I wouldn't be able to do that if I wasn't vertically integrated.

MR. BLUE: This is Greg Blue, with Cogentrix. You know, I think the GHG from power generation is going to go down with the amount of generation that's leaving the system. The OTCs, we heard some of the others. So, that's going to happen, anyway. And I guess it gets to a point where it's what type of gas unit are you going to have.

And if you have a peaker plant, for example, the majority of the time it's only going to run a very short amount of time. And because of that short amount of time, especially the short start-up time, the short stopping time, the short run time, minimum run times, that alone is -- per megawatt, the GHG footprint is much lower than some of these other plants that are out there, now.

So, I think some of that's going to take care of itself, I guess, in one way.

MR. SMITH: It's Mark Smith, with Calpine. Let me just add that I think there are plenty of opportunities to reduce GHG emissions from the existing fleet. Those may be missed opportunities, unless we change compensation levels.

I'll just give you two very, very simple examples. One that we think might be successful and another that's highly unlikely to be successful under today's market.

The one investment that we're aggressively pursuing is associated with one of the RMR contracts that was just granted or issued by the Board of the ISO. It's a peaking plant that runs fairly consistently, not for its peaking capacity, but for its voltage support in the limited area.

We would be happy to consider an incremental capital investment to put a device in between the gas turbine and the generator, a clutch, if you will, that allows us to disconnect the gas turbine once the machine is started, and run the motor, essentially the generator, as a synchronous condenser. Dramatic reductions in GHG emissions for the need that would be required in that area.

The only way we'll consider doing that is if we have an opportunity, through an RMR contract, to obtain not only cost recover our investment, but return on that investment.

So, that has a potential of being, you know, a true and real opportunity to reduce GHG.

Another that's less likely to occur, is routine and simple upgrades to combined cycle facilities that reduce the heat rate of those facilities and, therefore, reduce the GHG emissions.

There's no compensation in this market for reduced heat rates, right. Even, for instance, and I'm -- you know, with the energy margins as thin as they are, that's where the heat rate value would become in. You would become inframarginal and you would collect some incremental marginal energy. There's no compensation for that. So, it would not make sense. Unfortunately, it's a missed opportunity for investment in things that could reduce GHGs.

So, just as an example of one that does work and one that’s unlikely to work at least under the current structure.

MS. JONES: And do you think that RMR is the appropriate way to do that? Is there some other mechanism?

MR. SMITH: I would be happy to do that under a long-term contract.

(Laughter.)

MR. SMITH: Or, any other mechanism that makes -- puts me in a position of making a rational, economic decision. Taking my scarce capital and investing it in something that I expect to get a return on, and be compensated reasonably over the term.

MR. CUMMINS: Paul Cummins, Wellhead. I think the combined-cycle plants, especially if they’re slow, they’re going to have to get out of the way. That’s the only choice for reducing the GHG from thermal generation.

Peakers, on the other hand, I’ve said it before, I’ll say it again, they get out of the way. They’re there when you need them. How long are we going to need them? I think forever.

I happened to be in San Diego, the last time San Diego went black. We have three facilities there. Two of the three were instrumental in restoring the electricity to the San Diego Region. And the San Diego Region was black long enough that if those plants weren't there, but storage had been there, I don't think they would have gotten it restored. Because duration is important.

So, how long are we going to need peakers? I think forever. The question is optimizing and making efficient use of them, okay.

And I like the technology upgrade that Edison just did with their two peakers. And you know what they can do with a peaker that's got that technology upgrade? They can do exactly what Calpine was just talking about for the voltage services.

But it also gives so much more functionality to peakers. So, it becomes something more than a peaker, it becomes a new asset class. And I think that's the way to reduce GHG.

MS. JONES: Just to talk about something that's a little bit longer term, somebody mentioned transportation electrification. And that is going to be a major strategy. How do you -- how do you utilities see that changing your load curve? What do you see is the need for generation to meet that kind of a demand?

MR. LAWLOR: I'm going to have to answer that one in the written comments. I don't have any information on it.

MS. JONES: Go ahead.

MR. KRUGER: Vic Kruger, with San Diego Gas & Electric. We see the electrification of the transportation industry as a major change in our area. It sort of goes hand in hand with the last comments. You know, some gas-fired generation can act as an insurance policy or an enabling technology. Because if you do have a three-day, cloudy period, which is very seldom in San Diego, you still want to be able to charge up the cars, you know, if they're used in the transportation industry. And it may even reduce, you know, greenhouse gas emissions because if people can't rely on charging up a battery-only car, they're going to get a plug-in hybrid, or something that can also, you know, run with gasoline and stuff. So, overall, you have to balance all these factors together.

Vehicle to grid is just in its infancy, as well. That can help change the shape of the duck over time. And penetration of, you know, electric cars we think is going to be quite high in our service territory.

MS. JONES: Go ahead.

MR. LITTLE: Greg Little for -- oh, I'm sorry.

MS. JONES: Ross?

MR. GOULD: From our experience, right now we're looking at early adopters from the EV side. And they're easy to talk to. You can get them to shape load curve easier. But as we see the adoption try to, I guess, grow, and grow, and grow, and the more normal masses start using them, they're going to want them to perform like regular car, and they're going to want to plug them in when they go to the grocery store, in the middle of the afternoon, or right after work, or whenever, and they're not really going to care.

So, the big challenge that we see is how do we continue to shape the usage of those facilities, and that will be a big driver for us.

MS. JONES: And what are you looking at as the tools to help shape that?

MR. GOULD: Well, right now, it's real time of use and education.

MR. KRUGER: Also, you know, smart charging and the time-of-use rates are going to play a major role, I think, in San Diego. Where if you tell people I t's going to cost you four or five times as much to charge your car now, as later, the cars already have enough intelligence to pick the time they're going to charge.

And as we get into these cars with bigger, and bigger batteries, where they're not forced to charge every day, otherwise they can't get to work the next day. Some friends have the new Volt and they charge, you know, once a week. Because when you're over 200 miles of range, it's not as critical. And I think that works in well with the new rate designs, and things like that.

MS. JONES: Go ahead, Eric.

MR. LITTLE: Yeah, so in addition to those types of programs, of the pricing mechanisms and so forth, there's also the look at demand response in these types of areas. And battery storage in electric vehicles could very well be one of them.

Demand response has traditionally been thought of as reductions of load, when system conditions are such that resources are scarce. But if we've got over-generation conditions, the belly of the duck issue that's been discussed a lot here today, there could very well be incentives to consume at certain hours. And if those incentives are there, and you've got an electrified vehicle fleet, perhaps you very much have an incentive to have charging facilities at work locations, such that during the middle of the day, when the over-gen is going the greatest, your car is being charged at very, very low costs, for you then to go home.

So, I think it's a combination of the pricing elements and the demand response types of activities that we need to look for, first, and see what that does with the grid, and if that's able to take care of situations before we say, well, we're now going to need to build another 10,000 megawatts of gas resources. I don't think that we're there.

MS. JONES: So, in terms of the generators, what's your thinking about your role in terms of transportation electrification?

MR. THEAKER: Brian Theaker, with NRG. So, again, the fundamental is if we're going to get to the State's GRG targets, we're going to have to de-carbonize everything. And transportation, you know, is 40 percent. That we've got to, you know, squeeze that turnip as hard as we can squeeze it.

We think the transportation electrification is an essential component of that.

But as I noted in my comments, transportation electrification works as reliable as your electric system is. And, so, we think that there's still a role for gas in maintaining that reliability, to ensure that we have the kind of -- you know, the electric system we have now, where you don't think about whether the power's going to be there when you turn it on. It is, because it's been there for the last 50 years.

We think that gas is a component of maintaining that reliability. We also think that storage is a big piece of that. Because I totally agree with Eric, if we can get rate design and some of those things figure out, you know, we have a tremendous advantage, we can think about all of this solar in the middle of the day as a downside, or we can think about it as an opportunity to really take advantage of it, you know, in ways that will help the State achieve its policy goals.

MS. JONES: Shift it back to you for questions, comments?

CHAIR WEISENMILLER: Actually, let's -- let's go to public comment, and then we may have some wrap-up comments. At this point we have one blue card in the room. So, starting for public comments for those in the room, and then we'll go to those on the line.

Steven Kelly, come on up.

MR. KELLY: Steven Kelly, for Independent Energy Producers Association. And I really appreciate you putting on this joint energy workshop on this issue, because I think it's very critical.

This has been a fascinating discussion, and listening, sitting in the audience and being able to listen to the give and take, it strikes me that there's two colliding forces that are kind of moving to what I call unhelpful uncertainty.

One is this capacity gap, the capacity issue. And the other, that we haven't talked about too much, is untimely decision making. And I want to deal with both those.

I very much support what Tom Doughty was talking about, was that we need a durable process. I do have concerns that it would not be quicksand, that that process would be able to move forward in a timely manner to make decisions, to send signals to the marketplace about what to do next.

Let me briefly address the capacity gap, which has been talked about quite a bunch this morning. When I do back-of-the-envelope calculations, we've got the OTC units, that's about 9,000 megawatts. Diablo -- and that's, those are going to be done, in one form or the other, by 2020.

Diablo Canyon is 2,000 megawatts, shutting down by 2024, the beginning of that process.

And there's also something that was not mentioned, as I recall today, was the new ELCC calculation that is being -- is progressing at the PUC. Which the estimates that I've see might have the impact of reducing capacity counting for the utilities, from 2,500 megawatts or more. And that's likely to take place by 2019.

You add that up and you've got 13,000 megawatts of capacity that is uncertain going forward, beginning as early as 2019.

Neil Millar had mentioned that once you get beyond the OTC, you get into 4,000 to 6,000 megawatts of lost capacity, then you start to have some issues that arise. He indicated that he thought that might occur in 2021, 2022. I think it might occur quicker. And I'm looking at 2019, 2020 as the time frame that we might have issues emerging that are problematic.

And, then, you couple that with the CCA issue, where the utilities are presenting that roughly 40 percent or more of their existing load is likely to depart, and there's some uncertainty that we have about who's going to be buying the capacity. Not only on a long-term basis, but in the immediate term. We call this a capacity procurement gap. It creates another level of uncertainty that we have some concerns about.

Regarding timely decision making, the IRP is not supposed to be finished until 2021, or 2020, you know, the '18, '19 time frame.

The RA proceeding that is ongoing, I heard the ISO mention that they were going to take on a process that's 12 months. If that kicks over to the PUC, you've got to add 18 months for them to get a decision out.

That's 30 months. In both cases, we're looking at a 2020 time frame for decision making, at best, that would authorize the utilities to go forward and do something.

So, I view this as a colliding problem that we need to deal with sooner, rather than later.

Some potential solutions. If new infrastructure is needed, then certainly don't wait until 2020 to make those decisions. I think that is going to turn out to be too late, or you'll have to default to more higher cost resources, than you would otherwise want to have.

CHAIR WEISENMILLER: Steven, wrap it up. You can do it in comments.

MR. KELLY: Thank you. If I --

CHAIR WEISENMILLER: One more, yeah.

MR. KELLY: One last second. And I wanted to deal with the -- we've proposed a multi-year RA program at the PUC, in that process, and it's come up today in the conversations. There are two aspects of that, a procurement aspect and then a just, simply, a reporting aspect, which we have advocated for as a minimum start point to move forward.

That doesn't -- that will give the signals to the decision makers about where we stand, we think, as we move forward and look out three to five years in advance. And we think that would be a helpful solution as well. Thank you.

CHAIR WEISENMILLER: Thank you.

Anyone else in the room?

Anyone on the line?

MS. RAITT: Nobody on WebEx.

CHAIR WEISENMILLER: Okay. So, wrap it up. I'll make a few comments. First, I wanted to thank everyone for being here today, for the conversation we've had.

I think, again, conceptually when you look at it, the issue going forward is going to be going forward cost, volume of going forward, and price curves. And, you know, certainly having implications on our power market. We've talked about -- I want to discourage people from thinking it's only a gas issue. It's certainly one of the reasons why we're losing a nuclear plant, certainly one of the reasons why we're starting to lose some hydro plants.

So, again, as you go forward, as the forward curves go down, you know, you're going to see more resources that have issues. You know, certainly encourage people to look at the economics on it, basically on renewables, again.

It's just the characteristic, as you add more zero cost resources to the mix, you're going to bring down wholesale prices. That is both a cost and opportunity.

I think in terms of trying to figure out what to do next, you know, part of it, again, is the focus on what's the solutions. As long as we have excess capacity, the value of additional, you know, generation is pretty close to zero. So, you know, part of the question is how do we have an orderly process for tidying things up some?

You know, and basically, trying to make sure that we've identified, quote/unquote, the right plants, right location, right characteristics. And, you know, frankly, some of the rest of you should go away, be it packing them up and moving them, or whatever. But we'll have to go in that direction.

Long-term trends, I was going to point to a recent study that was done by IEA, in Irena, looking at basically how to get the world to the under 2 level, 2060. And, certainly, the IEA looked at it with nukes. Irena, the German's contributed money, so it's without any additional nuclear plants, it's pretty much renewables and energy efficiency. But there is some role for case even in that Irena case. But again, more on the operational side.

So, again, the issue we need to come up with is how to get to the right mix question and move forward from there.

COMMISSIONER RANDOLPH: Yeah, I'll just say I think you hit the nail on the head. We need an orderly process to kind of, you know, analyze these issues and come up with the right solutions, in a manner that's timely enough to be effective.

And, so, this discussion has been useful I kind of posing some of these thoughts and possible solutions. So, I really appreciate everyone's participation in this.

VICE PRESIDENT DOUGHTY: Well, Chair and Commissioner, thank you for allowing ISO to participate, both as presenters and here, on the dais. I took away a lot of notes today and I learned a lot.

I will tell you that we've been looking forward to this discussion for a long time. We've had written communications with many people in this room, meetings with many others, hearing about these. But to bring them all to the table, in one session, I think was invaluable.

Some of the headlines that I captured today. We are acknowledging together that we are long in capacity. Neil Millar showed a graphic, showing that we are 57 percent, still, gas capacity. With renewables growing quickly, that pie is shrinking. It's just natural.

Solar peak has doubled in the last two years and we'll only continue to see that.

So, as that is played out, we've heard words that the existing growth in renewables are squeezing margins down to where fossil units are just not able to participate.

So, we know that some plants need to go. We want to retain the most valuable units. And as we see this precipitous decline in capacity, we've got to be very careful. And there's a certain level of urgency, now, to make sure we put in place programs to retain those units we really want.

We heard that we're missing longer-term procurement signals that can exist between the one-year RA and the ten-year LTPP or IRP processes.

We heard terms today around highly-valued asset classes that may make good use of a living wage in the AS space. Thank you for that.

And then timing, we heard about the need to fortify the timing so that we have an earlier assessment of RA showings, to give more notice to plans for what they've got to look ahead to in the coming year.

We also heard about the possible need for a more significant RA redesign, perhaps with some level of central procurement. And, then, certainly the need to better integrate ISO backstop and the RA procurement program.

So, those are just a handful of the things that I took away today. There are certainly many more insights that will come out through the record.

For us, we think this is a moment of significant urgency to do this right, and to get it taken care of, now, before we move into a place where plants that we seek to retain are beginning to depart the system.

So, with that, I'll prepare to depart this room. Chair, thank you, again, for welcoming us.

CHAIR WEISENMILLER: Actually, I was going to ask Heather to remind people when written comments are due.

MS. RAITT: Yes, just a reminder, the written comments are due May 8th. And that's it.

CHAIR WEISENMILLER: So, the meeting's adjourned.

(Thereupon, the Workshop was adjourned at 2:34 p.m.)

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

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