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CALIFORNIA ENERGY COMMISSION

In the matter of) Docket No. 12-IEP-1D
Preparation of the)
2012 Integrated Energy Policy Report)
Update (2012 IEPR Update))

Lead Commissioner Workshop on Strategies to
Minimize Renewable Integration Costs, Requirements and
Improve Integration Technologies

CALIFORNIA ENERGY COMMISSION
HEARING ROOM A
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

MONDAY, JUNE 11, 2012
9:00 A.M.

Reported by:
Peter Petty

APPEARANCES

Commissioners (and their Advisors) Present:

Robert B. Weisenmiller, Chair
Carla Peterman, Lead Commissioner, 2012 IEPR
Andrew McAllister, Commissioner

Staff Present:

Suzanne Korosec
Lynette Green
Melissa Jones
David Vidaver
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Also Present (* Via WebEx)

At Dais

Timothy Simon, California Public Utilities Commission (CPUC)
Matthew Tilsdale, CPUC

Panelists

Mark Rothleder, California ISO (CAISO)
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Ben Kroposki, NREL
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John Kistle, AES Southland
Tom Pierson, Turbine Air Systems
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John Hernandez, Pacific Gas & Electric (PG&E)
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APPEARANCES (Continued)

Public Comment

Todd O'Connor, Critical Path Transmission
Stephen O'Kane, AES
*Ben Mehta
Bill Keese, Eagle Crest Energy Company
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*Steve Davis, KnGrid

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P R O C E E D I N G S

JUNE 11, 2012 9:06 A.M.

MS. KOROSEC: I'm Suzanne Korosec. I manage the Energy Commission's Integrated Energy Policy Report Unit. And welcome to today's workshop on Renewable Integration Costs, Requirements and Technologies.

Just a few quick housekeeping items before we begin. Restrooms are in the atrium out the double doors and to your left, we have a snack room on the second floor at the top of the atrium stairs under the white awning for coffee or snacks. And if there's an emergency and we need to evacuate the building, please follow the staff out of the building to the park that's diagonal to the building and wait there until we're told that it's safe to return.

Today's workshop is being broadcast through our WebEx Conferencing System and parties do need to be aware that you are being recorded. We'll make an audio recording available on our website in about a week, and we'll make a written transcript available in about two weeks. We'll have two opportunities for public comment today, one before lunch for those of you who are unable to stay until the end of the day, and one after our final panel. During the comment periods, we'll take comments first from those of you in the room, followed by those who are participating on WebEx and then, finally, those who are phone-in only.

When making comments or asking questions, please come up to the podium at the center of the room and use the microphone so that we can make sure that the WebEx participants can hear you, and it's also helpful if you can give our Court Reporter a business card so we can make sure to have your name and affiliation correct in our transcript

For WebEx participants, you can use either the chat or raised hand functions to let our Coordinator know that you'd like to make a comment, and we'll either relay your question or open the line at the appropriate time.

We're also accepting written comments until close of business on June 18th, and the Notice for today's workshop, which is available in the foyer, on the table out there, and also on our website, explains the process for submitting comments to the IEPR Docket. So with that, I will turn to the dais for opening remarks.

COMMISSIONER PETERMAN: Thank you, Suzanne. Good morning, everyone. Welcome to the eighth and final workshop of a series of workshops the Energy Commission is doing as part of the 2012 IEPR to develop a Renewable Strategic Plan.

We have spent the last seven workshops covering a number of topics and opportunities related to renewables, specifically identifying how to address some challenges, and so we've talked about how to site renewables in preferred locations, how do we reduce the cost of the renewables, how do we finance renewables, how do we staff renewables, what is the workforce that's needed, how do we interconnect renewables using the latest new equipment, and what renewables do we need to invest in, in the future. Our last workshop dealt with research and development opportunities and, indeed, there are many new technologies on the horizon.

Well, none of that matters if we don't have a way to integrate renewables into the grid in a way that provides reliable and safe power, 24 hours a day. And so, I think this is fitting that we're ending with this eighth workshop with a workshop on integration.

We're going to discuss here a number of the ways in which we have integrated renewables to date. As the California ISO has said, there are three pillars of success for integration, and they identify these as natural gas plants, Demand Response, and storage. We'll be taking each of these in turn, as well as looking to you to figure out better ways and systems we can invest in going forward.

Excited to have here on the dais with me are

Chair Weisenmiller, who I will turn to now for opening comments. We will also be joined by Commissioner Timothy Simon from the Public Utilities Commission, and when he arrives, I will also give him the opportunity to make welcoming comments. So with that, thank you, look forward to the discussion. Chair, any comments?

CHAIRMAN WEISENMILLER: Yes, again, I'd like to thank everyone for their participation today. In the last IEPR, we had workshops on some of these technologies, particularly storage, and the intent today is to actually cross-compare, first, to get the context of what we need for renewable integration in terms of the operational characteristics, and then to compare across those, the existing gas units, with some potential enhancements there, storage and Demand Response.

And Demand Response, again, we're talking not as much about basically load shifting as things that can respond within a 15-minute period. So if the wind drops, or if we lose a transmission line, we're looking for what we can do with Demand Response in that context, not day ahead, but something that you have to be able to respond at that moment. So, again, I think we're trying to cross-compare across the technologies and understand the tradeoffs. So, again, thanks for your participation today.

MS. KOROSEC: All right, a little background. Every two years, the Energy Commission prepares an Integrated Energy Policy Report that covers a variety of energy topics and makes policy recommendations to the Governor, with an update prepared in the off years.

In 2010, Governor Brown directed the Energy Commission to prepare a plan to expedite permitting of priority renewable generation and transmission projects. To provide the foundation for that plan, the Energy Commission developed the *Renewable Power in California: Status and Issues Report* as part of the 2011 IEPR, which described the status of renewable development in California, some of the challenges to future renewable development, and current efforts to address those challenges.

The report also established five high level strategies as the basis for a more comprehensive Renewable Strategic Plan that will be part of the 2012 IEPR Update.

Today's workshop, as Commissioner Peterman said, is the seventh IEPR workshop related to those five strategies. Our prior workshops covered renewable benefits, preferred geographic locations, interconnection issues, retail rates and costs, jobs and economic development, and financing and research and development.

And the discussions and input from these workshops are going to be used to develop specific near-term actions that the State needs to take to begin addressing the challenges that were identified in the Renewable Report.

The third strategy identified in the report covered both interconnection and integration and, since we covered the interconnection portion in our May 14th workshop, today we're focusing on how to minimize integration costs and requirements.

Our agenda today starts with a panel to discuss integration challenges now and in the future, and what's needed to address those challenges at both the transmission and distribution levels. Our second panel will focus on integration services that can be provided by natural gas plants, and that panel will be followed by an opportunity for public comment, and then we'll break for lunch. Panel 3 will cover Demand Response programs and how they can be used to help integrate renewables, and our fourth panel will talk about energy storage technologies that can provide integration services. We'll have another opportunity for public comment at the end of the day and hope to adjourn around 5:00.

So before we get into the panels, I'll just give some quick background on the topics that we're covering today, that were covered in the Renewable

Report, which discussed integration issues and detail at both the transmission and distribution levels, and I encourage folks to look at the two chapters of the report that discuss these.

At the transmission level, to meet demand for electricity, grid operators have to plan for hourly, daily, and seasonal fluctuations of electricity demand and supplies, and for unexpected outages for both power plants and transmission lines. And when committing or dispatching resources to meet demand, they have to consider the unique operating characteristics, constraints, costs, and environmental impacts for each electricity supply source.

The Renewable Report cited the California ISO Study on 33 Percent Renewables that was done for the PUC's Long Term Procurement Proceeding, which estimated that the share of California's electricity provided by variable renewable resources, like solar and wind, is expected to rise to 22 percent in 2020.

Variable resources have several characteristics that will require increased flexibility in the way California's electricity system is operated; they have a variable fuel source that is difficult to forecast accurately; they have a typical generation pattern that doesn't match system load; they have a generation pattern that doesn't smooth out variations to flow a predictable product onto the Grid; and they are unable to dispatch on command, or contribute to system inertia or frequency control.

Higher penetration of renewables will increase the need for ancillary services, including these that are listed in the table from the Renewable Report that can help balance demand and supply fluctuations, can help maintain grid conditions within prescribed limits, and provide reserves for unexpected events over different time horizons. Integrating large amounts of variable renewables will require regulation to follow real time ups and downs, and generation output, or voltage, or frequency. It will require ramping up and down generation from other units to follow swings in generation, will need spinning reserves provided by generating resources that are standing by and ready to connect to the grid, and will need replacement power for outages.

California currently relies on large hydro and natural gas generators to provide many of these services, but as more renewables are added to the system, it will become increasingly challenging. System operators will also need strategies to address potential over-generation issues that occur when there is more generation than there is load to use it, which typically occurs when the combination of imports, hydro, wind, and solar generation exceeds load, mostly at night or on the weekends, and generation has to be sold at a loss, or backed out, or shut down to balance the system.

Successful integration will also require improvements of forecasting of wind and solar technologies so that transmission and generation dispatchers can know how much variability that they need to plan for.

As Commissioner Peterman mentioned, there are three types of infrastructure that are being studied to support renewable integration, storage, Demand Response, and gas-fired units, and the ISO has called these resources Partners for Success, with each resource playing a different role, as shown in this figure from the report. Natural gas units can provide quick start-up, rapid ramping, regulation, spin reserves, and energy when intermittent resources aren't available.

Energy storage can provide flexible and controllable ancillary services at the transmission level, through voltage support and frequency response, and can store excess energy when on-line generation is excess of load.

Demand Response can help with integration by combining smaller loads to provide regulation or ramping through automatic controls that turn individual loads up or down, as need. And we'll hear much more about each of these during our panels today.

The Renewable Report also identified the challenges on the distribution side with integrating large amounts of renewable DG into the distribution system. California's distribution system only allows one directional flow from generation to substation to customer, and as more DG is added to the system, generation from these resources could be greater than demand and then you get backflow into circuits or substations. This is going to require new protection and control strategies to avoid damaging the electric system.

Another challenge is islanding, when DG systems continue to provide energy to a circuit, even without power from the utility, which is a serious safety concern for utility workers. And as more DG units are added to the system, the current anti-islanding devices may not be able to detect problems and send the signal to immediately stop producing power.

Utilities have also expressed concerns about what happens when large amounts of DG are tripped or lost at the same time, which could happen in response to a transmission-level outage or fault. Also, increased amounts of renewable DG can cause voltage variations that exceed current standards.

A good portion of the distribution system was designed in the mid-20th Century to provide power to relatively simple devices, and not to sophisticated electronic equipment that is used in today's homes and businesses, which is much more sensitive to variations in voltage and frequency.

And as well as the physical challenges, there is also a need for better coordination between distribution and transmission system planning, and for uniform and open standards to integrate intelligent technologies, renewable generation, and communication devices into a Smart Grid. Currently, neither California nor the Federal Government mandates adoption of specific standards related to Smart Grid technologies and generation devices, but that will be needed to ensure that products are compatible, function well, and support interoperability and communication between technologies.

And I see Commissioner Simon has joined us, so is this a good spot to stop and -- all right, thank you.

All right, the Renewable Report discussed several activities that are helping to address integration issues. Efforts at the transmission level include integration studies by the ISO as part of the

PUC's Long Term Procurement Plan. The 33 Percent RPS Integration Study filed by the ISO in July of 2011 provided preliminary results identifying the requirements to operate the grid reliably in 2020 with 33 percent renewables. The preliminary results of the ISO's analysis of the five scenarios studied in the LTPP indicated that the fleet of resources that was modeled could provide the integration needed in most cases just by changing the way that it's dispatched.

The ISO has also embarked on a several year market and product review for renewable integration to help address operational issues by aligning technical requirements and market incentives. And also, the ISO offers two Demand Response products that are laying the foundation for the role of Demand Response in integrating renewables.

The Renewable Report also noted that the ISO is scheduled to implement a regulation energy market in the spring of 2012 that would allow Demand Response and energy storage to submit bids to provide ancillary services.

The ISO is also working to improve its forecasting techniques to reduce uncertainty, and therefore the amount of standby capacity that will be needed to compensate for the variations between generation and load.

Other ISOs in the U.S. have modified their tariff structures to allow load resources like DR to participate in their markets; for example, PJM in the east allows load resources to provide forward capacity, synchronized reserve and regulation, and uses DR products for regulation and spin reserve. And we'll hear more about PJM's experiences later on today.

In addition to integration studies as part of the Long Term Procurement Plan, the PUC is contribution to integration efforts by evaluating the need for and benefits of energy storage. Assembly Bill 2514, which was passed in 2010, directed the PUC and publicly-owned utilities to evaluate cost-effective and viable energy storage systems and determine appropriate targets by October 2013. The PUC opened its proceeding in December 2010 and we'll hear about the current status of that proceeding in this afternoon's Energy Storage Panel.

Also, in November 2006, the PUC called for expansion and augmentation of the investor-owned utilities' DR Programs and, since then, utilities have increased their reliability and price responsive DR programs and created a utility portfolio that was projected to reach 3,000 megawatts in 2011. Many of these utility programs could provide supporting energy and capacity services and markets with increasing penetration of intermittent renewables.

Finally, the Energy Commission's Public Interest Energy Research Program has funded a wide array of research projects that will develop better forecasting tools for wind and solar generation, develop and demonstrate energy storage technologies, identify ways that Demand Response can support renewable integration, and develop the Smart Grid of the future.

Integration efforts at the distribution level include solutions to planning and operational challenges for integrating DG that are being addressed under the umbrella of the Smart Grid. Modernizing the distribution system is likely to speed up as a result of Senate Bill 17, which was passed in 2009, which requires the utilities to develop Smart-Grid Deployment Plans.

And in July 2011, the IOUs filed their Deployment Plans at the PUC that identified Smart Grid technologies to be evaluated for inclusion in the General Rate Cases, and publicly-owned utilities are also developing similar plans.

Utilities have also reported that they're investing millions of dollars to upgrade aging infrastructure to increase visibility, flexibility, safety, and reliability, and on the R&D side, the PIER program is leading an effort that includes several California utilities to measure and share information on how distributed PV generation affects voltage, power flow and harmonics on the distribution system, which will provide some real world insights and data, and help identify strategic upgrades and smart grid technologies that will be needed.

SMUD also has a pilot project that's funded by the Department of Energy to demonstrate inverter communications, using SMUD's Smart Meter infrastructure. By December of this year, SMUD plans to develop software that will interface with PV inverters and existing automated metering infrastructure, and allow inverters to communicate data, look for faults, and send control signals which will help in developing future standards.

The Renewable Report also discussed a study funded by the Energy Commission and the ISO that looked at experiences in Germany and Spain with integrating high amounts of renewable DG.

The KEMA Study, which was distributed generation in Europe, compared the European and California grids to see what lessons could apply to California's integration efforts. I won't go into a lot of details of the study, but some of the suggestions included additional telemetry and ability to curtail for system operators, to allow them to monitor and control DG systems, exploring a range of DG scheduling, re-dispatch, and curtailment options, that could be implemented in interconnection agreements, tariffs and, in market models, to accommodate backflow. Instead of extensive upgrades to California's existing protection systems, it might be possible to modify settings on some of the newer microprocessor relays that are already installed.

And one way to connect large amounts of DG at relatively low cost is to restrict the amount that can be interconnected to feeders, substations, or local load areas, which would reduce the risk of backflow and other impacts.

So that's a very brief overview of the information in the Renewable Status and Issues Report that relates to today's topics. And so, with that, I'll turn to Commissioner Simon.

COMMISSIONER PETERMAN: Thank you, Suzanne, for that overview. And welcome, Commissioner Simon and his staff from the Public Utilities Commission, appreciate you all making the trek to join us. Commissioner Simon's extensive work, particularly on gas, made him an ideal person to reach out to from our sister agency to have engaged, and happy he was able to join us.

Commissioner Simon, any opening remarks?

COMMISSIONER SIMON: Yes, thank you, Commissioner Peterman, and the staff and stakeholders here, Commissioner Weisenmiller. This is the first time actually we've had a chance to be on the dais together, so thank you. It's great to be here in Sacramento and, you know, the interesting thing is, to all the stakeholders that are here, I'm in conferences all around the country, or we are, where this very topic is being discussed. And, clearly, California is the Petri dish in terms of observations of how we are going to successfully employ, integrate, and maintain the system reliability that's being discussed today.

So you know, there's a whole industry of conferences that I have a sense do pretty well in this space, be it by way of the number of invitations that we receive, but, in reality, the real work is done right here, maybe without the same level of coverage, glitz and glamour, and dinners and receptions and things of this nature.

As you know, we have our Rule 21 settlement which is designed to clearly improve the interconnection process on the distribution level. As the presentation covered, we have a number of open proceedings at the Commission, many of which are mandated by the Legislature that is allowing us to better evaluate the challenges and the benefits and the opportunities of this very dynamic grid, transmission and distribution system that we are entering renewables, as well as other energy sources into.

If we look at what's going on in Southern California with our SONGS facility, and the fact that we are looking at August as the earliest for one unit and possibly later for another unit, it's not a question of when or if, it's really when we will have to test all of the various dynamic components that we're developing in some critical circumstances, so -- and that critical circumstance is peak load; as I like to say, black-outs in California is Latin for "Recall." You know, I use the term "outages," but we don't want outages either.

And as we increase our Renewable Portfolio, or move further towards our 33 Percent Standard, I don't need to tell you that those challenges exponentiate. So, mechanisms like storage, our Net Energy Metering system, increasing our distributed generation to the 1,200 megawatts that the Governor has put forth, all these factors come into play.

So you're the real experts, I sit here and listen so that, when I put forth a vote, I can be better informed. I will be in and out today, my Advisor, Rahmon Momoh, who was kind enough to park my car since I ran into some U.S. Open traffic in San Francisco, who will be back in the room shortly, but again, I want to thank you for all the hard work and dedication you put forth and look forward to hearing your contributions today.

MS. KOROSEC: All right, thank you. So with that, we'll move into our first panel and I'd like to introduce our moderator, Melissa Jones.

MS. JONES: Good morning. It's a pleasure to be here this morning and today our first panel will be focused on discussing the types and levels of ancillary services that are going to be needed to integrate large amounts of renewable resources, both at the transmission and at the distribution level. We will also be discussing some of the uncertainties associated with those needs.

We've got three panelists this morning, Mark Rothleder from the California ISO, he's Executive Director of Market Analysis and Development. We also, on WebEx have Lori Bird, who is a Senior Analyst with the National Renewable Energy Laboratory. And, in addition, we have Ben Kroposki, who is the Director of Energy Systems Integration with the National Renewable Energy Laboratory. And so we're going to have 10-minute presentations by each of the presenters and let's go ahead and start with Mark. Thank you very much for being here today.

MR. ROTHLEDER: Thank you. Thank you, Commissioners, for the invite. What I'll be discussing today is kind of summarizing what our studies, Renewable Integration Studies, are telling us so far in terms of operational requirements for the system.

So if we look at our traditional load curves, this is a typical load curve where load comes up in the morning, kind of flattens out at a level in the afternoon, and sometimes you have an evening peak that occurs late in the evening, and then a kind of ramp-out as load as you go later into the evening. In the off-peak hours, sometimes existing we have over-generation issues where you have too much generation and you have to basically back resources down to minimum loads, sometimes the prices currently go negative during that time. But this load shape is a very predictable load shape and it kind of -- it's a system and the resources are managed, committed in such a way and dispatched in such a way to manage this load curve and balance it.

As we move forward, you start to bring in additional amounts of wind generation and the green line here and the yellow line represent wind and solar generation, which the quantities of those megawatts of production are on the right-hand scale. So you can keep on going through.

So as you increase the amount of renewable resources, what really is leftover in terms of balancing the system is what we call net load, is really represented by this red line. And what we can see here is that, with larger amounts of renewable resources, this shape, this typical load shape that we now manage, is going to significantly change.

A couple things that are prominent are that, while the morning load pull is similar as the morning load pull comes up, you've got solar to offset that, you quickly have a kind of -- you could have a ramp out of load because now the amount of solar generation exceeds the amount of load as the load starts to flatten out. And so you have this now drop-off of balancing need as you go across that eight o'clock, nine o'clock time period.

Now, you get kind of into the second -- typically, we get into over-generation conditions in the morning, early morning hours, now you potentially can run into a situation where you have too much generation on in the middle of the day, so then the question is, well, how do you back these resources down that you need later -- in this case, two hours from now, to meet the peak and, then, basically have them ready to meet that peak?

So you may actually have over-generation conditions in the middle of the afternoon, which is a pattern that we do not currently have, and so it's a new operational paradigm that we need to be prepared for.

As you get into that evening peak, now, rather than dealing with potentially a 3,000 to 4,000 MW ramp, you may be dealing with, in this case, 13,000+ MW over two hours, and then the question is do you have the resources either available, positioned, committed, and ready to take that ramp of that evening local? And then, after that, you quickly drop off where you don't need that generation. So you can see from this that the amount of cycling of the resources, the amount of minimum load, inflexibility on a resource, is going to really matter in this new paradigm. Next slide, please.

COMMISSIONER PETERMAN: Excuse me, Mark, before you move to that next slide, just one quick question. I see that this is representing January 2020 --

MR. ROTHLEDER: Yes.

COMMISSIONER PETERMAN: I'm just wondering if you were going to take, you know, in August or summer peak, what would change specifically this over-generation, middle of the afternoon, might there be load to meet that?

MR. ROTHLEDER: So if this is a summer pattern, then we could create these patterns for any period, 365 days of the year, now that we have the profiles. The summer will probably not be as difficult in terms of an over-generation pattern in the middle of the day, but what you will see is you can still see some of those ramps in those evening periods. And what you'll also see is probably a shifting of the peak and, so, rather than the peak occurring around 3:00 in the afternoon, 4:00 in the afternoon, you may see the peak shift by a few hours because, at that point where the combination of solar generation is dropping out and load is still on, air-conditioners are still coming on in the evening, you may see the actual peak shift. It may be a lower peak, so you may have some capacity -- or, sorry, the renewable capacity -- of meeting some of the load, but the shifting of that peak may be observed. And so, in that case, the ability of things like solar to store and maybe ramp out slower may be providing value in meeting that shifted peak.

COMMISSIONER PETERMAN: Thank you.

MR. ROTHLEDER: So in addition to the kind of daily variability, which honestly is predictable variability, okay? We can kind of predict what the pattern is going to be, going in today, we can try to commit the right resources, get the right flexibility on line, but there's also a degree of uncertainty around this. And the uncertainty is now not just load uncertainty, but also supply uncertainty. So, whether the cloud cover can come over the solar panels, or wind variability, there is a range of varied uncertainty around that net load curve that we need to be prepared for.

In addition to the daily variability and uncertainty, there is also intra hour variability uncertainty, and we measure that by looking at what the expected average load will be for the hour, and then kind of measure what the five-minute average net load will be, the difference between that and the five-minute net load, and the hourly net load, and that is what we call load following quantity.

And then there's a difference between the five-minute and kind of the fine tuning as you get into real time operations, and you need to still balance the system every second to second, and the difference between five-minute variability and the actual variability is effectively what you use Regulation for, so your regulation which is on an automatic generation control, is doing that second by second fine tuning balancing.

So from an operational perspective, what's the issue if we can't balance the system in an adequate way?

Well, we have certain operational standards that, when we are bound to operate to, and if we do not meet those operational standards, we can be fined, or, worst case scenario, if we're not operating within those standards, we run the risk of jeopardizing the reliability system in case of some larger event occurring. So our measurement standards are currently CPS1, which measures the Area Control Error of a Balancing Authority, a Balancing Authority Ace Limit which measures, again, kind of within a 30-minute basis how well we're balancing the system, Disturbance Control Standard, and the Disturbance Control Standard is basically how well we respond to a contingency event. And I want to make sure it's clear that a contingency event is not a wind variability event, or a solar event, a cloud cover coming over a solar field, that's not what is considered a disturbance, it's more like a large resource basically tripping and you being able to respond to that and ensuring that we maintain frequency within certain standards.

This slide here just illustrates that we have seen a degradation of some of our Control Performance Standards in terms of our operational standards that we're trying to meet. The green line is basically what we have to meet and, in 2010, we started to see some degradation of that performance, as illustrated by the blue bars.

A couple of things have happened in that time period, one is we moved from a standard to a balancing standard in 2010, that is under a trial period. That allows for more flexibility to occur between balancing authorities, so we can lean on each other more frequently and in larger quantity while still maintaining performance. However, in doing so, we may have reduced our performance of our CSP1 performance.

The other thing that has happened over this period of time is that we have increased amounts of renewable resources, and so some of the variability on wind and solar resources has contributed to some of this maybe degradation of performance.

Last week, when we hit our new record of wind, 3,100 MW of production of wind, the same day, same week, we also achieved a new all time peak for solar resource production at 843 MW. Now, these seem very small when you compare to where we are expecting to go over the next eight years. We're talking about 5,000, 6,000 MW of capacity and production potentially, and you realize that this is a significant change over a short period of time.

So what our studies have done and have been trying to do is quantify the operational requirements and we've been trying to do that in different timeframes, to cover different timeframes of operational need. As the first slide indicated, we have to have enough flexibility to cover that daily ramping of resources and that's something that we've coined as maximum continuous ramp, how do you take those long relatively slower ramp periods and have enough capacity that's moveable to cover those periods?

If we look at our Net Load Curve today, some of the longest continuous ramps are in the 18,000 MW range, actually, with renewable integration, so some of those ramps actually may decrease because your capacity at peak is being met, and so your longest continuous ramp periods may actually decrease. However, the speed at which you need the ramp capability may actually increase, and so we need to be prepared for maybe shorter ramps, but potentially faster ramping capability. Next -- I'm sorry, previous slide.

Operating Reserves, that's our traditional spinning and non-spinning. We don't see that significantly change because it's more a function of your load, rather than the variability. Regulation, we do see a potential doubling of regulation requirements which currently run 300 to 600 MW for our system, and we probably will see something up to about 1,000 MW of regulation need at higher renewable integration levels.

Load following, which is something currently not a product, but we are introducing products to support load following, including flexible capability, over an hour, we probably would need about 3,000 to 4,500 MW, and in the future 2,500 to 5,000 to 6,000 MW, depending on the conditions.

Then the last one is Frequency Response. This is something both inertia and Governor control on resources during low load periods, or during periods when you have a lot of renewables, you may not have a lot of Frequency Response to address the contingency events, and so we will need to maintain -- more about maintaining -- sufficient sufficiency response capability to be prepared for such events.

I'll leave these slides to my Panel 2.

COMMISSIONER PETERMAN: Mark, just a quick follow-up question, so I'm just looking at this slide previously, which is very helpful, and I'm just trying to conceptualize where the issue of over-generation then plays into these five categories on how I should be thinking about what additional services may be needed for that, and where it's coming from.

MR. ROTHLEDER: Well, we kind of cross the gamut of continuous ramp, regulation, load following, so why we focus a lot about upward capability, there is a downward capability issue in terms of over-generation condition. And the question there becomes how you minimize the amount of minimum load of resources, conventional resources generally have minimum loads that have to be beyond to the extent you can cycle resources off, to the extent you can curtail resources, there are options and ability to manage the over-generation condition. Regional coordination is also part of the solution in terms of over-generation condition, as is storage. Demand Response is -- I'm not sure is a significant player in terms of over-generation because, at that point you need actually more load, so if you have some dispatchable demand that you can actually increase the demand, it may help, but oftentimes Demand Response is talking about curtailing a demand to get some additional supply effectively.

COMMISSIONER SIMON: Mark, in this surplus or over-supply, is there an estimated amount, if any, of displacement that is going to occur -- I guess probably the most glaring example is what occurred up north at the Bonneville Power Authority and, as I understand, based on their water tables, we may have another event of that nature. I think that was 10,000 MW. Has there been any forecasting on what amount of displacement we're seeing?

MR. ROTHLEDER: Yeah, let me go to my next slides, and I do have a few studies, but I won't go through the details of how we developed these studies, but through the studies we basically tried to come up with shortages of both upward capability and downward capability. Next slide, please.

And in the upward capability direction, depending on the scenarios, we see little or no need for additional capability based on the expected infrastructure that will be there. But that is based on an assumption about a significant amount of Demand Response being developed, as well as energy efficiency being developed in the cases of the trajectory cases. If you make some compensation for the potential for under-performance of energy efficiency programs, we do see a potential need of 4,600 MW of resource flexibility, flexible capability. Then the question is, well, where do you get that flexible capability? And some of those resources needed for the upward flexibility may be needed in local areas and, so, we're doing some studies there to indicate that maybe about 3,000 MW of local resources may be needed and necessary, and some of those resources will meet the flexibility needs, and there may be some residual amount of need system-wide.

Timing-wise, there may be some needs arising as early as 2018, and 2018 is an important year because of the once-through cooling retirement schedule. Next slide and I'll just help answer the question about downward capability.

We do in our studies, we do observe a need of about 3,000 MW of operational flexibility in the downward direction. And the question is, do we have enough flexibility in the fleet to do that. And what the studies have shown, and the studies were using a flexible -- we're using flexibility across effectively interchange across the West. What we observed is that we didn't see a significant amount of shortage of downward flexibility needs; in other words, we found the ability to meet the simultaneous load and the need for downward flexibility, however, I'm a little skeptical around that solution because some of those solutions indicate that we will be exporting from California as much as 5,000 MW of net export out of California. And, for my experience, we've never seen anything lower than about 2,000 MW net imports, okay, it's very rare that we would ever get into a net export situation.

So the question that we have to ask ourselves is, is that a realistic dispatch condition? Are we really going to be able to turn down other resources across the West that they may need for their peak period, including coal resources, to basically absorb an over-generation condition in California? I think if you put some additional constraints around what the net exports out of California may be, you would probably see a situation where this need for downward flexibility and capability would increase, and I think you would also observe the need to potentially curtail resources in California, and then you're going to have to weigh what the resource that would be curtailed. Do you curtail the renewables? Or do you curtail other resources? This will be exacerbated in the springtime period where you have high hydro conditions, spill conditions potentially, and potentially high amounts of renewable production early in the morning.

So I don't want to have a perception that downward or over-generation issues are not an issue, I think from my review of the results, I think we need to continue reviewing this issue and not potentially be masking a potential real situation.

COMMISSIONER PETERMAN: Mark, thank you. And this is somewhat of a follow-up question to Commissioner Simon's question because I think it was also touching upon this issue, that with the current generation that we're seeing now, for example, with the wind, if we were not to curtail the renewable resources, then what are those renewables displacing in terms of other generation in California? And is that generation -- that thermo generation -- needed for other reasons such as local reliability, etc.?

MR. ROTHLEDER: Yeah, I think it will be displacing thermal generation and the more flexibility you have in cycling a thermal generation off shorter cycle periods, combined cycle, gas turbines, the more ability you'll be able to absorb and displace that. And we know that the once-through cooling resources will be largely retired, or replaced, or repowered, that actually does provide some flexibility because, instead of having to keep those resources on at high minimum loads, you'll be able to basically potentially cycle them off to bring them down to lower minimum load levels.

It does matter on the technology. Some of the combined cycles right now do have relatively high minimum loads. Some of the newer combined cycle technologies hopefully will have lower minimum load ability to cycle more often. Those operational features will be important in this new world.

CHAIRMAN WEISENMILLER: Yeah. I had a couple comments. First, I was going to ask you, have you done any assessment of how much inertia we need in the system?

MR. ROTHLEDER: Yes. We did a study with GE and what it indicates is that -- and I think it was in one of my previous slides -- we need about 700 to 800 MW of frequency response, quick frequency response capability, something that can basically respond in seconds. In order to achieve that, what the study has indicated is that we basically have to have about 3,000 MW, 3,100 MW of head room on resources that basically are frequency responsive. When I say "frequency responsive," they have Governor controlled capability. And, so, about 3,000 MW of Governor controlled capability at any given time needs to be unloaded and available on line system, synchronized.

CHAIRMAN WEISENMILLER: Okay. The next question was, of the -- now that we're at 3,100 MW of wind, what's been the maximum drop-off of wind within one hour?

MR. ROTHLEDER: We've seen some of our largest drop-offs within an hour, I think, have been around 700 to 800 MW of drop-off.

CHAIRMAN WEISENMILLER: Okay. And I guess the flip side is how much of an increase in an hour?

MR. ROTHLEDER: I think it's comparable to that, but I don't have the exact numbers.

CHAIRMAN WEISENMILLER: Okay. And in terms of how much Demand Response do we have right now available to the ISO to respond to system changes?

MR. ROTHLEDER: That’s a hard question to answer. When you say "available to the ISO," there's about 2,400 MW of Demand Response or interruptible programs. A lot of those programs are not managed by the ISO, they're managed by the utilities. They invoke and take actions on those based on either forecast conditions, or forecast of prices going into the day ahead.

In terms of our responsiveness, it's probably within the day a couple thousand during a summer period that we would have.

CHAIRMAN WEISENMILLER: Yeah, I know when you looked at San Diego and Orange County, I think on the day ahead numbers we were at -- I'm going to say about 500 MW, and on 15-minute, we were down to tens of MW.

MR. ROTHLEDER: That's about right.

CHAIRMAN WEISENMILLER: So I would assume overall a couple thousand, again, we're down to more like 100 or 200 for that sort of 15-minute --

MR. ROTHLEDER: A lot of the Demand Response right now needs at least advance notice, a lot of it is not available and going to be within 15 minutes, but if you do call upon it, it's going to have to stay off for a long period of time.

CHAIRMAN WEISENMILLER: And at this point, do you have an idea of how much storage is available to the CAISO?

MR. ROTHLEDER: Well, the big storage devices are going to be basically the hydro storage devices and there it's 1,000 MW. If you also include some of the storage facilities in the Department of Water Resources, you get a significant amount of storage. If you're talking about storage that is smaller scale, regulation, frequency response of storage, with kind of the newer battery flywheel type stuff, we're talking about very small quantities at this point?

CHAIRMAN WEISENMILLER: Would you guess under 10, or 10's.

MR. ROTHLEDER: Ten.

CHAIRMAN WEISENMILLER: Ten's? Okay. And in terms of -- do you have a sense of how many hours of over-generation we had this year and how deep the over-generation was?

MR. ROTHLEDER: So I'm going to answer it this way, a true over-generation event that we basically had to pro rata reduce supply? I don't think we got into that type of over-generation condition. How often did we have negative prices indicating that we had an over-supply? It was roughly about five percent of the hours.

CHAIRMAN WEISENMILLER: Okay. And I guess the last one, although I suspect it's probably better to hold off until the next session with you, is that you've talked about the need to bring the gas generation units down and quite a bit gets to the characteristic of the gas units. Obviously, a lot of the existing fleet has more, say, tens of hours of start-up. And relatively high minimum load. And so that gets to the question, if you're really trying to respond, we need flexible fast start and, so, I know you talked about the need for a certain amount of flexible fast start gas units, as opposed to the existing fleets. Do you want to talk about, at least, foreshadow those studies for the next panel?

MR. ROTHLEDER: Yeah, I think our studies do indicate an increased amount of cycling of resource need and that net load curve in the first slide indicates that we may need to turn down resources at a period of time that we don't do it today. Today, we keep those resources on and get them on in the morning, or Monday, and that's kept on all week, or for the period of the peak. For these events where we're going to have to potentially bring on a resource for two hours, we're going to probably need resources that can cycle on and within 15 minutes to an hour to be prepared for that event, and not cause this over-generation condition at the same time.

COMMISSIONER PETERMAN: Thank you. I think the Chair set you up nicely for your last slide, so do you want to finish up with that?

MR. ROTHLEDER: Thank you. So some of the next steps. I think we're actually at a point now, we have a pretty good handle around the operational requirements in terms of quantity of what do we need. Do we have an exact number for everything? No, but I don't think you need an exact number. I think we know the ranges, what we're going to need.

I think the discussion needs to now shift to how we make sure that we have that. And there's kind of two timeframes of making sure you have it, it's what do you do on a daily basis to manage the fleet that you do have, and there we have market mechanisms, and we probably need to augment some of those market mechanisms as additional products to manage the fleet in such a way that we are preparing for the variability events.

But then there's a different timeframe of how do you meet the need. And there, it's the more what we're kind of having a discussion here is, how do you plan the fleet for the future and have the mechanisms and the resource capability in place? And I think there, the mechanisms we have right now, the procurement mechanisms we have now, may be a little bit too piecemeal, and I think we need to start taking a look at more of a comprehensive how do we get the right resources in the system and maintain those right resources in a period that looks ahead? And I think you need to start looking at some of those mechanisms that then can value and assess and optimize both Demand Response, storage, and also conventional resources and the role they play in meeting the operational requirements of the future.

Lastly, it's incumbent on the ISO, again, to continue to evolve the market to better manage the variability, better forecasting tools, and better market products, market products that meet the system needs, and also do not limit the technologies that potentially can provide those services. And we've done some of those things and we need to continue doing those things to ensure that we're not limiting the resources and the capability in the system. Thank you.

COMMISSIONER PETERMAN: Thank you. Just one more follow-up question, Mark, and you may not be the best person to ask this, but I think you've characterized well that the CAISO has identified more or less the needs, etc., and I'm thinking about the other balancing authorities and to what extent they are at the same -- they've done that same degree of analysis, and I'm just wondering if you can speak to the extent which your products are being used by the other balancing authorities in California, or what coordination is happening amongst them, as well.

MR. ROTHLEDER: So within California, there's the study work that we did in the CPUC Long Term Procurement Planning, actually it extended beyond just the California ISO, it was a California view of what the potential requirements are. Now, how those requirements would be met, we're only kind of focusing on what within the California ISO, what the potential needs were. And in the other balancing authority areas, why we quantified some of those requirements, and we did production simulations to determine whether there was enough fleet capability to meet those. We have not done a coordination of how best to coordinate across the whole state, or, frankly, across the West. We are starting to look at some studies that are looking at regional coordination, both within California and across the region, across the whole western area connection, to better manage the need for fleet for flexibility and meet the variability's of the future. Some of those studies do support some of the things we're going to get into, I think, a little bit later about energy and balanced markets and stuff like that. Some of those mechanisms that would allow for more flexible intertie utilization, I think, are a part of the solution.

CHAIRMAN WEISENMILLER: Yeah. I think it's probably safer for me to make the comment that reading the FERC Outage Study, I mean, the message was pretty clear that we have too many balancing authorities and not enough visibility and coordination across those balancing authorities. And I think, certainly, it's been a consistent message that, if we can get the intertie scheduling more to five minutes, as opposed to an hour, there is substantial benefits. But I would have to say that there would be substantial benefits from having fewer balancing authorities and greater visibility. And certainly, when you look at the slide on the CPS, you have to be concerned if -- if the balancing authorities are all leaning on each other more, but with poor visibility and the current fragment of the structure and WECC's frankly inadequate performance on the outage, that we're really going to have problems in the Western reliability.

MS. JONES: Thank you. And I think that's a pretty good segue into the work that Lori Bird has been involved in. Lori is on WebEx and the one study that we're familiar with is the Western Governors Association Study that she has been involved with, but she's also very aware of a number of other studies that have gone on in terms of integration challenges. So, Lori, I'm going to turn it over to you. Thanks.

MS. BIRD: Yeah, thank you very much. It's a pleasure to be here this morning. Yeah, I think that was a nice segue into what I'm going to discuss. You can go to the next slide. I'm going to mainly talk about a new report that's coming out from the Western Governors Association, I contributed to that report and it talks about various options for addressing integration challenge in the last -- I think we've already pretty much covered, you know, the challenges, the variability, and the uncertainty of the wind and solar, so we can go to the next slide.

But, getting back to what we just heard, the discussion we're just starting to have, is the Western -- outside of the California ISO, we have hourly scheduling in most parts of the West, a large number of balancing areas, 37 balancing areas, not a lot of cooperation between those at this stage, although increasing amounts of that effort to try to encourage that. But that's the context the West is currently operating in and it does pose a lot of challenges for the integration of renewables.

So this study, and the Executive Summary is now available on the Western Governors Association website, and the full study will be available shortly, I don't think the whole thing is up, to my knowledge, yet. But it's available at that website, at least the Executive Summary. So this study goes through a number of options that states could use to integrate larger amounts of renewable energy with some look at, well, what might be some of the least cost options in certain areas without -- it's not a quantitative analysis, it's based on existing literature, existing studies that have been done, and it's really a review of all those. I'm actually filling in, I guess, really. The Regulatory Assistance Project led this work and edited it, we contributed to this, and it was funded by the Energy Foundation with support from DOE, as well. Also, I'll just mention, there was a pretty good sized technical review committee with a lot of stakeholders involved.

So the report focuses on -- there are nine chapters in the report and each one focuses on one of these areas, and these are the options for cost-effectively integrating renewables in the West. And so, just quickly, I'm going to go through a couple of them, and not in very much detail, you know, we only want 10 minutes here, but the report goes in and describes the issues associated with each of these, you know, what the benefits are of trying to do some of these, implement some of these options, and some recommendations for what states could do to try to facilitate some of these things, so the first being expand subhourly dispatch and scheduling, so moving away from hourly scheduling in much of the West, but trying to get that down to five, 10, 15-minute scheduling, or at least 30-minute would even help in some areas. So facilitating dynamic transfers between balancing authorities is another issue that could be important for California, in particular, trying to get some of the renewables from other parts of the West; implementing an energy imbalance market; improving forecasting; encouraging geographic diversity of the renewables, which can help reduce the variability; improving reserves management, and I'll talk about that a little bit later. We've already had a lot of talk about Demand Response, but basically, you know, that can be one of the more cost-effective mechanisms for dealing with large events where that generation is not there, where the forecast is wrong, and then accessing greater flexibility in the existing fleet and from generation. So next slide.

So I just have this graph here to kind of indicate that there are different cost solutions, depending on the specific power system, as well. And we have some indication in the report, you know, it's not -- we have cost information where it was available from different (inaudible), and we have summarized that, at least where it was available. We've also -- the report also includes, and I didn't include it here, a table basically, or graph, that kind of compares the cost of the various options, you know, in a very general way.

But I guess I'll just comment, you know, in many cases, flexible demand, things like that, can be pretty low cost solutions compared to other things like storage, in general, although a variety of mechanisms may be needed.

So just to get into a little more detail, but not much on each of these topics, I'm going to cover them very briefly, but the issue of dynamic transfer, so this is the ability to move generation from the balancing area where it physically resides and have it be controlled by the receiving balancing area, which is one of the things that is being looked at and can be used for the California RPS. So there are some challenges with doing dynamic transfers in the West, dealing with the fluctuations in voltage and power flows on the transmission lines can get challenged, determining whether or not there are lines that need to have dynamic transfer limits on them, and identifying where those lines are problematic is probably one of the first steps that need to happen. And then determining priority for improving or easing those restrictions and in some regions, you know, some of the reliability procedures such as voltage control and Remedial Action Scheme, arming, is being done manually, and this limits the ability to do a lot of dynamic transfers where you have these power flow and voltage fluctuations that are a lot more significant than they would be without dynamic transfers. And it's a challenge for the operators. And so there's a need to automate those procedures in a number of areas, is certainly necessary. There is a lot of other detail in the report on this. Next slide.

An Energy Imbalance Market, there's been a lot of study and work on this, in particular, this option. And there is, I'm sure everyone knows, the Western State Energy Board and WECC has a lot of information about the Energy Imbalance Market that they put forth on their website, but this would be a centralized market that would allow re-dispatch of generation every five minutes, and it would basically enable balancing areas to utilize regulation across a larger area to access the most cost-effective resources for balancing. So it can really reduce cost and it would result in five minute scheduling and dispatch of the, you know, re-dispatch which can also be quite helpful.

So the next steps for that were some key recommendations for -- can you go back -- you know, for moving that forward, there are still some issues that need to be resolved, one is exploring financing options, you know, having PUC discuss the costs and benefits of this to the ratepayers, addressing the concern that EIM could lead to an RTO. There's been a lot of discussion of that. But I think there's been a lot of work on that issue, in particular, showing that it certainly can be structured, and there's no reason why it would lead to an RTO, or that it needs to do that if it's structured properly. Another potential issue is this question of market manipulation and, so, you know, if some work could be done to determine or just to design the market so that would not be a concern. So I think that's all I'll say about that particular -- but there are a variety of things that states can do to help move that discussion along and try to make a decision if that's useful.

You know, studies do show that the larger the area, you know, there's more participation in the energy imbalance market, certainly the more benefits that you get to the region. So it's important if it does move forward to have a large number of participants in the market. Okay, next slide.

We've already heard a little bit of discussion about the need for improving forecasting and, you know, this can basically just reduce the amount of reserves that are required by understanding more fully what you're going to be able to get from a renewable at different times. So some of the recommendations for advancing that are to use more regional forecasts, studying the feasibility of different forecasts for day-ahead unit commitments, and schedule updates. And this little question of the forecasting ramp, so reviewing whether existing forecasting equipment can adequately predict ramp, and improving ramp forecasting, in general. Next slide.

Another option for integrating renewables is encouraging geographic diversity, so making sure that the renewables are spread over a larger area, so that the variability is reduced. And so, this has been an issue, I think, in Texas, in particular, they've seen a lot of their development in West Texas and now they're starting to see that diversity location -- other places are doing this, as well. So ways of doing this, you know, investigating the pros and cons of siting optimization software, consider siting wind and solar to minimize the variability of the output, but there's a lot of -- there is a balance here that a number of -- the cost of the renewables, of course, is an issue, as well, so all of these things must be balanced. Supporting right-sizing of interstate lines could also help encourage geographic diversity. Okay, next slide.

So Reserves Management -- and this is a bit of -- there's a lot of stuff in here in this category of Reserves Management, what do we mean by this? So there are a variety of options that could be used to help reduce the amount of reserves that are needed to address the variability of the renewables, and so there are a number of different options that are discussed in the report, one is reserves sharing, so the idea of balancing areas joining together and, if there's a surplus or deficit of generation, netting those out before determining the regulation reserve requirements. So that's one strategy where dynamic calculation or reserve, you know, determining how much reserve is needed at different times because it's not going to be steady, it's going to be changing over time with the renewables.

Another thing that, you know, it's a bit controversial, I think, but could -- some additional study, it may be worth some additional study, is this question of can you used contingency reserves for wind events, so there's a question of reliability concerns with this approach that, you know, if you use the contingency reserves for a wind event, then maybe there's not enough if there's an outage on the system, but there could be some analysis performed to determine the benefits of that is perhaps the next step for that one.

And then ramp rate controls on variable generation is another option that can be explored, or perhaps utilized to a larger extent, you know, limiting the amount of ramp and using control equipment to indicate what the variable generating unit, to minimize those ramps. Okay, next slide.

And we have heard a lot about Demand Response already. As I mentioned, it can be a pretty cost-effective -- I just wanted to show that it can be a pretty cost-effective solution and there's already a lot going on in this area, so here are some recommendations for complementary Demand Response that can complement the wind and solar. You know, one issue might be to test the value propositions to assess customer interest, and strategies for controlling loads up and down frequently, that's one area that states could conduct some research. Cultivating strategies that earn customer confidence in Demand Response, encouraging third-party Demand Response Aggregators to participate, and then making sure that Demand Response can compete on a par with supply side alternatives in utility resource planning. Next slide.

Okay, this is my last slide. So this is the general topic of increasing the flexibility of existing generation to meet a new generation. And so I think this is an area for some additional thought. What are some things that can be done? One is conduct a flexibility inventory, and it sounds like that is already being done by ISO and some -- analyze the potential for retrofitting less flexibility generation plans, and look at the incentives or disincentives for plant owners to invest in flexibility, particularly for new plants. You know, it costs more to have flexible generation typically, so there needs to be an incentive for them to do that. Identify strategies to minimize or avoid cycling. I think, you know, there are a couple more here, but those are the main ones. So that's basically it, you know, as I said, this study goes through in more detail, you know, I tried to give kind of a whirlwind tour of the recommendations, this isn't even a full summary, it's not even a full listing of all of the recommendations in the report, so I refer you to the full report if you're interested in any of these particular topics in greater depth. So thank you very much. That’s all I have at this time.

COMMISSIONER PETERMAN: Lori, thank you very much. This is Commissioner Peterman. I heard a presentation on the report when I was at a WIEB, a Western Interstate Energy Board meeting, with a number of the other states from the West, and we all found it very interesting, and a number of the recommendations here would be useful for all the states to think about. And I'll just say that, we'll just assume that the actual report is submitted to the docket, so that we can pull upon it as we're thinking about recommendations.

I just had a couple quick follow-up questions. Number one, on subhourly scheduling, this always comes up that's something that's ideal, I guess the question for you, as well as maybe for Mark, is why are we not seeing it, then? Where are the barriers to having this happen? This seems to be something that there's general consensus on value for.

MS. BIRD: Well, you know, obviously we do have it in all the large markets in the U.S., it's these smaller balancing areas that have not done it in the past, so it requires significant change for them and their operating systems, so I think there has been some progress --

COMMISSIONER PETERMAN: Is it time? Is it cost?

MS. BIRD: You know, I think ultimately the cost should be reduced with the operational efficiency, but there is cost, you know, upfront cost, in making that shift, but ultimately there should be cost savings resulting from a more efficient operating market.

COMMISSIONER PETERMAN: Okay, thank you. And my second question, you can tell me if this was touched upon in the report or not, and I can just whip to it, in terms of geographic diversity, what type of scale does the report recommend? Are we talking about diversity within a few miles? Or a larger footprint?

MS. BIRD: It's usually a larger footprint. I mean, basically it can vary, I mean, you want to make sure that the profile of the generating plants, in particular units, they're not going to be aligned, right? So it can vary depending on what kind of terrain you're talking about, or so forth. But a lot of it is weather patterns, you know, moving through and you want to make sure that the same weather system isn't going to knock out all of your plants at the same time; there was an incident in Texas just a few years ago where there was a weather front that moved across and it took out a lot of their plants at the same time. So, you know, I think the greater diversity that you can get, the better, you know, there are a lot of other considerations in mind, but making sure that you're not going to be affected by the same weather patterns is essentially what we're talking about.

COMMISSIONER PETERMAN: Thank you.

CHAIRMAN WEISENMILLER: Yeah. Hi, this is Chair Weisenmiller. So a couple questions. First, it would be great if, when your report goes into the Docket, that basically certainly the cost chart on the flexibility options, it would be great to get that in.

MS. BIRD: Okay.

CHAIRMAN WEISENMILLER: In terms of dynamic transfers, part of my question is, my impression was that, you know, the amount of dynamic transfers available is actually relatively small, so I was trying to get a sense of whether you've done any estimate of the magnitude, whether it's tens, hundreds, thousands, or tens of thousands of megawatts potentially for dynamic transfers?

MS. BIRD: Well, I think, you know, there's been a lot of work by some committees in the West on this issue of dynamic transfers, and there's this question of whether some of the lines need to be limited, and how much transfer can actually be -- how much can be transferred over those particular lines. So there are some studies that have quantitative numbers that are coming out -- I might have to follow-up with you after this to actually point you to them, but there is work being done on that. But I think it's an open question. I think it's an area where there have been some dynamic transfers, there are some challenges to it, and some of the balancing areas have had their issues with them under their current reliability procedures. I was talking about there is manual RAS and so forth, you know, they're doing these things manually, and so there's limits to what they can actually do on certain lines for that. So those are real challenges to larger scale implementation of it. And so that's what needs to be addressed, I think, in some of these areas. You know, lines that are key, where we really want to be doing some dynamic transfers, making sure that they're trying to address limits on those particular lines is maybe the next step.

CHAIRMAN WEISENMILLER: Okay, certainly if you could submit for the Docket some of those studies that would be useful. Another observation, again, you talked about the Energy Imbalance Market, and frankly getting to an RTO was why there's some way of dealing with some sort of combined dispatch would be very valuable. Obviously, that would take a long time, so the question, again, is how to get intra-hour scheduling on the ties -- on how to focus on at least getting some stuff sooner as opposed to the perfect, but much much later.

MR. ROTHLEDER: Commissioner Weisenmiller?

MS. BIRD: Yeah --

MR. ROTHLEDER: This is Mark Rothleder. On the dynamic transfers, in the California ISO, we have a couple thousand MW of dynamic transfer, most of it is usually -- there are a couple different flavors -- one is a jointly-owned unit that just dynamically schedules in whatever portion of its owned output of a resource, it's usually fairly static, and then there's other dynamic transfers that are dispatchable dynamic, and so we actually can dispatch the resources externally through the dynamic transfer on a five-minute basis. And there we have about 500 MW or so of those types of dynamic transfers, and then we've approved a dynamic transfer policy that would allow renewables to also be dynamically scheduled and into California, and right now we've got a couple hundred megawatts of those currently, but we expect those to increase.

In terms of dynamic transfers, in terms of it being a solution to the problem, it is partially a solution to the problem, especially if you can access additional flexibility from externals, it also could contribute to adding to variability to meet California load because you could be transferring what is now a firm schedule, which is being balanced by external balancing authority, you may be transferring that variability as a dynamic transfer of a renewable resource. So it works on both sides of the equation, potentially increasing the variability transferred, and also a solution to the variability, depending on the types of dynamic transfer that you're transferring.

CHAIRMAN WEISENMILLER: Okay, but of the existing dynamic transfers, isn't Sutter -- it seems like that would be a significant chunk of that, or is that separate from that?

MR. ROTHLEDER: It's a type of dynamic transfer, it's a pseudo tie, so it effectively looks like it's a resource inside at the California ISO.

CHAIRMAN WEISENMILLER: Okay, thanks.

MS. JONES: Okay. Thank you very much. Thanks, Lori. So our first two presenters have talked about grid level integration, and our third presenter, Ben Kroposki, will be talking about distribution level renewable integration. So, thank you.

DR. KROPOSKI: Okay, thank you.

COMMISSIONER PETERMAN: And, Dr. Kroposki, looking forward to your presentation. Just looking at your slides, if you want to jump relatively soon to the examples, I think we've got some of the other information already in the docket.

DR. KROPOSKI: Understood. I'd like to thank you for this opportunity to speak today and, so, go ahead to the next slide. So the first thing I'll just hit on this slide is that you have a goal of 12,000 MW of localized energy generation or distributed generation, which is what I'll be talking about, how to integrate that into the grid. So, next slide.

So this is a busy slide, but it just kind of is a laundry list of all the technical concerns, and we've hit on these in most of the topics -- or talks, so far today, so I won't spend any time here, really, except to mention on the bottom, on distributed issues, the reality is that interconnection concerns are real, but they're also solvable and we've managed basically to come up with solutions to almost -- to all of these issues at some form or another. So go ahead to the next slide.

So as a generalized topic in discussing distribution integration issues, you know, the reality is that the current grid was really designed around both power generation and delivering that central-station generators to customers. As distributed generation is integrated into the system, that does cause backflow of power from these distribution generation systems, and that requires new protection systems and control strategies to avoid damaging the electric system.

There is a high variability in distribution system designs, which is a challenge, as opposed to the transmission system which is fairly standardized in terms of the way it's designed, and allows for a bi-directional power flow. The distribution system has, you know, grown up over the last 100 years, in a variety of different configurations. It doesn’t make for a completely standardized solution very easy, although, that being said, I think that there are lots of technology options out there that can alleviate a lot of concerns in that area. And standards are definitely an important part of the solution.

The other thing that we see is this really rapidly increasing number of requests to interconnect, and so there needs to be a way to reduce the costs and complexity, and the length of time to approve these types of interconnection requests.

So the next set of slides I have in here is sort of learning from experience, the German example. And the reality here is that Germany is clearly the world leader in distribution level of grid integration of renewable energy sources. If you take a look at the little chart here, you can see right now in the German grid, they have over 50 gigawatts of installed renewable variable generation capacity, with almost 30 gigawatts of wind and 25 gigawatts of PV. Go ahead to the next slide.

Then the question is, where is all this PV located? The reality is 80 percent is at medium voltage or low voltage systems, so that means it's basically distribution level connected. I put a little comparison over to the side there to kind of look at the difference between the German Grid and the California Grid, you can see Germany has got about 80 million people, about an 80 megawatt peak, with over one million separately installed PV systems, totaling about 25 gigawatts of PV. Compare that to the current situation in California, 37 million people, 60 megawatt peak, 150,000 systems, roughly, and about three gigawatts of installed PV capacity. So you can see there's about a factor of 10 roughly in what Germany has been able to install into their system to date.

The reality also is that, you know, most of this has happened in the last five years, so they have really ramped up with the last couple years being around seven gigawatts of installed PV into the system. So go ahead to the next slide.

The other interesting thing is, you know, where in Germany is all of this located, it's really highly concentrated in the southern area of Germany, it actually is kind of a unique situation there where the majority of the north is wind power, and the wind installation is on the northern side if Germany, and the southern side of Germany is where the installation of solar power is, for the most part.

This is one of the most recent realities of what's happening in Germany. And this particular slide shows the solar production from May 25th of this year, where they had basically a world record in solar generation with over 22 gigawatts of solar power being put into the grid, and that accounted for roughly about 50 percent of the load on that system. You'll notice a little bit of difference there with the handout and this particular slide, but what this is really causing is that load shape to drastically be modified, and what you saw CAISO present for the 2020 load profile is what they're already starting to see inside of Germany with this amount of solar integrated into the system.

Some of the balancing areas, if you will call them that, or transmission area operators within Germany have started to become "exporters," so that situation that the CAISO mentioned, where they could possibly see export of power from California, it's happening within the balancing areas of Germany right now.

So going back to some of these integration issues, this one highlights one of the utilities' major concerns, which is reverse power flow causing increased voltage levels, they definitely are seeing this, although you can see the penetration level, which this is occurring -- they have about one megawatt of solar, and only really 100 kilowatts of peak load -- are fairly high, so, really the reality is, on the distribution level, some of these problems are happening at much higher penetration levels than we kind of normally put flags into the system right now.

For example, in California -- and a lot of utilities use this as a rule of thumb around the country -- is a 15 percent before they will go into a supplemental review, this is much higher than 15 percent, although they are obviously seeing some of these issues.

This is the overall looking at a substation transformer that is supplying power back to the transmission system. You can see over the last couple of years this system has moved from sort of what they would consider their normal generic load profile to where they are exporting during the summertime, quite considerably, having reverse power flows back into the transmission system in Germany. So go ahead to the next slide.

COMMISSIONER PETERMAN: A quick question, so these are higher penetrations than the 15 percent rule of thumb being used in the U.S., so what would the percentage equivalent be?

DR. KROPOSKI: Oh, if you go back, I mean, so instead of 100 percent, these are 100 to 200 percent, much higher as a percent level.

COMMISSIONER PETERMAN: I don't know if I really understood the answer.

DR. KROPOSKI: As opposed to 15 percent, they are more like 100 or 200 percent.

COMMISSIONER PETERMAN: Oh, okay. Thank you.

DR. KROPOSKI: So they're already --

COMMISSIONER PETERMAN: I mean, I heard it, I just didn't believe it, now I believe it, okay.

DR. KROPOSKI: Yeah, they're way way above sort of the nominal levels that we consider for doing these studies, in Germany. So go to that last --

So initially, you know, what caused all of this deployment, obviously Germany was offering some extremely high incentives, they also had very high goals on distributed solar. They have most recently been backing off their incentive program considerably with the idea that that would slow down the market a little bit, the fact is that low PV prices have really continued to drive the market in Germany. And they weren't expecting seven gigawatts to go in last year, but that did, and again this year they're still seeing a lot of demand for putting in PV systems.

So the other things that have sort of created this, they have an extremely simple standardized interconnection process that basically allows the PV system to interconnect. If the utility deems that they do need a system upgrade into the distribution system, they're able to rate base the cost of that upgrade. So that is something a little different than you see sort of normally in the U.S., where they have been incentivized in the utility system to allow the interconnection.

The other thing that's going on right now is that these high penetrations really have demanded how PV systems need to be changed in terms of the design and operations of them. Basically, Germany has gone through a process of updating their interconnection guidelines to require volt var control capability, trip setting variations, so under and over a voltage frequency setting, the ability to ride through faults -- that capability and the ability to do remote curtailment for system stability. So these sort of lists are now implemented in the German Grid Codes so that they can handle these increased levels of solar.

And then they also have, if you look at their longer-term goals, they basically have an 80 percent renewable goal by 2050. In order to do this, they are now really examining not only their interconnects, but how they do transmission system planning and upgrades throughout the country, and how they'll handle this large an amount of renewables, and they have to manage that with their interconnects to other countries around Germany.

This just highlights some of the work that we are doing with the utilities in California to address some of these particular issues, I'll just list them there, but we are working with a variety of the utilities here in California to evaluate these new technologies as they come on-line.

And I just wanted to highlight some of the advanced capabilities that we have at NREL in terms of our Energy Systems Integration Facility where we're testing and evaluating some of these high penetration scenarios in an operational environment.

This kind of highlights a project that we're doing with SMUD, where we're looking at high penetration, residential deployments of PV systems, and then monitoring the impact of these systems on the utility grid.

You can see how we're using this to do scenario analysis around cloud cover and the impact visually on distribution systems. We're also able to take -- and this is one of the things that, as we look at these new technologies and requiring inverters and other technologies in the system, you want to be able to test those in larger scale deployments. This is an example of what we call Hardware-in-the-Loop testing, where we're able to take, for example, a new inverter that may have volt var control, implement that in the lab, test that at real power, deploy that into a simulation of a much larger distribution system, and we take that into a model that we validated with actual field measurements, and then we're able to loop that back into the control and look at the impact on the Grid system.

This is my last slide, it really talks about what are the solutions when we're looking at distribution level interconnection. First, on the technology side, obviously distribution system upgrades and whether that's upgrading lines, or transformers, the real question ends up being here who pays for it, it may not be the least expensive solution when you want to look at how to get this much renewables integrated into the Grid. Obviously, you have to weigh those upgrade costs vs. other options that you have. For example, the second bullet there talks about advance functionality for inverters, so moving the inverters to what we're seeing in Germany where they have this volt var control, the ability to do fault ride-through, remote communications and power curtailment, all of these have been proven in the lab. We've done a lot of research and experiments both at NREL and the California Energy Commission has also funded a lot of work in this, where we've developed this type of technology, we just haven't deployed it at a mass scale yet.

The next bullet there is really looking at what kind of standardization do we need around those control and communication interfaces. The key there is obviously, if you're going to start looking at distributed resources in the system, those control and communication interfaces need to be secure in ways to make sure that that is properly integrated into the system operations.

We are doing some work with understanding the best locations to integrate new renewable deployments, and then integration, as we move to higher and higher penetrations, will need to look at how do we bring in localized load control and energy storage to reach the higher penetration levels.

In terms of standards and regulatory solutions, obviously we need to go back and take a look at the interconnection standards that are out there, the requirements. Basically right now there is a little bit of a roadblock in that current interconnection standards, whether it be IEEE1547, UL 1741 which is the certification procedure that implements that, and then things like Rule 21, the small generation interconnection procedure, and WDAT, all are based on basically 10-year-old interconnection procedures that did not expect us to reach high penetrations of distributed generation, and those need to be updated to allow some of this advanced functionality. We also need to look at how we can streamline some of this interconnection procedure if we allow this functionality to occur, so that these systems can be more quickly integrated into system operations. And then, looking at how to streamline some of the permitting process along with this would also be helpful, especially on the distributed generation aspects.

So next slide -- that's it, I'll end here and take any questions.

COMMISSIONER PETERMAN: Thank you. Normally we ask panelists for their recommendations, but all three of you have been very helpful in providing those upfront and, arguably, we could spend all day just hearing these presentations, I found them very interesting. I don't have any follow-up questions right now.

CHAIRMAN WEISENMILLER: I just had one, which is when we can expect the inverter standards to be upgraded?

DR. KROPOSKI: So in May -- let's see, last month of this year, there was a meeting on IEEE1547, which ends up sort of being the base document because it's a national standard, that's going through a revisions process and it actually has to be reaffirmed next year, so we're looking at putting together an Addendum to allow these types of functionalities into that system. There is, you know, a little bit of a lag between when these things get decided in terms of standards, and then when they get put into certification processes, and when everybody's rules updates to them. So, unfortunately, it takes on the order of a year or two, unless they end up being mandated changes from some regulatory position. So there is a process right now where these standards are being reevaluated. I think there is the opportunity to speed that up.

CHAIRMAN WEISENMILLER: Yeah, that would be important. As you know, we have about 100,000 systems in the field now in California, we're obviously trying to grow that pretty quickly --

DR. KROPOSKI: Right.

CHAIRMAN WEISENMILLER: And it would be better to have sort of a appropriate inverters in place now, as opposed to a couple years out when we're sort of double or triple that number.

DR. KROPOSKI: Absolutely.

CHAIRMAN WEISENMILLER: So that may be something that the PUC may want to act more proactively on.

DR. KROPOSKI: Yeah, I would agree. I mean, I think the challenge that Germany has had is that they did not update their standards until they probably had about three-quarters of a million systems installed, and so they are actually trying to figure out ways to go back and retrofit some of their inverters for frequency response.

COMMISSIONER SIMON: Briefly, could you expand on the who pays for what scenario? Are you speaking in between FERC rates and CPUC rates? Market vs. --

DR. KROPOSKI: What I mean by that is, if you look at the variety of solutions that you can come up with to increase penetration levels and still operate the system safely, some of those, you know, maybe allow the inverter to operate differently, or some of those may be that we would upgrade the distribution system components, for example, re-conductor the cable to a larger wire size, or switch out a transformer. The question ends up being, you know, who pays for those system-wide upgrades? Is it the person that wants to install the distributed generation source? Or are they just rate-based across the utility system? In Germany, they've decided to go with that approach where they've allowed any system-wide upgrades to be rate based across their system. That’s allowed the PV deployments to not have to incur those costs, but you have to take into account who ends up paying for that type of system.

MS. JONES: Well, I'd like to thank the panelists. I think we've covered most of the questions and I think we're at our time limit. So, thank you again.

COMMISSIONER PETERMAN: Thank you, Ms. Jones, for your moderation, as well as just your advanced work to get these questions and these presentations together, this was a good first session. Thank you very much.

MS. KOROSEC: All right, if we can have our second panelists come up to the table and our moderator, Mr. Vidaver.

COMMISSONER PETERMAN: I will say, I'm really excited about this next panel. I've been wanting to see this panel for over a year and I'm glad we found an opportunity to work it into an IEPR Workshop. So, thank you in advance to all the panelists who will be joining us.

MR. VIDAVER: Good morning, Commissioners. I'm David Vidaver with the Energy Commission staff. We're here to talk about gas, one of the three pillars of integration, and the one that tends to be frowned upon the most. We are going to talk about what gas needs to be able to do and Mark is here to tell us what gas needs to be able to do to provide the services that increasing levels of intermittent resources require, and then we're going to talk about what gas is able to do and where that's going to move forward.

Would you like introductions now or do you want parties to introduce themselves as they're called upon to speak?

COMMISSIONER PETERMAN: Whatever you prefer.

MR. VIDAVER: I'll let them introduce themselves when they speak. The first question I have is of Mark, whom you've met. The ISO is developing a series of new ancillary services; there are increased needs for existing services. The question I have for him is, what does gas need to be able to do to provide these services? What metrics are used to value these services? And indicate that the operating characteristics of a planner such that they can provide?

MR. ROTHLEDER: So this is a continuing work in progress, what attributes -- what are the characteristics of the resources, especially gas resources, does the fleet need to be? And the studies are interesting in the sense that what we need, ideally, is resources that can ramp fast, start quickly, low minimum loads, can provide regulation, can provide either inertia because they have a rotating mass, or provide some kind of frequency response and/or a voltage response. Depending on where the resources are located, they also may need to be able to provide some kind of local service capability -- voltage or responsiveness to a contingency event in the local area.

That said, I also want to say that the studies have also indicated that resources that may not have these attributes may also be helpful in unloading resources that do have these attributes, so there is some tradeoff that can occur on potentially less flexible resources that can unload flexible resources. But you need to have some mix of resource fleet that has embedded within it at least some minimum amount of flexible capability, so that you can do those tradeoffs.

COMMISSIONER PETERMAN: Mark, can you just clarify that last statement? I thought it was interesting, but I don't know if I fully got it, which is that you have resources that don't have these attributes, but they can help unload resources that do?

MR. ROTHLEDER: Yeah, so let's assume you need 3,000 MW of ramp flexible stuff, okay? And at the same time, you need to meet your load. Well, if that ramp flexible stuff is loaded to meet load, well, it's not helping the flexibility at that time, anyway, okay? However, if you load up another resource, either increase your imports, or load up another resource that is relatively inflexible, you may be able to unload that resource that is then flexible and is positioned to provide that flexibility. So it's a mix of total capacity and a mix of combinations of resources that can achieve the objective. So part of our study, they're trying to analyze, well, is it a -- can you meet the needs by adding additional flexible capacity? Other types of capacity, and we hope this will inform that decision.

CHAIRMAN WEISENMILLER: Okay, well, just to pin you down for a second, when you talk about flexible or fast start, you know, what sort of numbers are you looking for?

MR. ROTHLEDER: Well, it depends on the characteristic, the need over what period. So as my earlier slides indicated, to make the daily ramping capability necessary, you may need as much as 16,000 to 18,000 MW of something that's moveable. Now, does it have to be fast start? No, not necessarily. It could be interties, it could be stuff that is scheduled over an hour, okay? So you probably are talking about in terms of fast start capability, it really depends on the mix of resources, when they're being used to meet load, when they're being used to meet the flexibility needs, and so while I'd like to give you an accurate answer, it really depends on the combination of the conditions. Roughly speaking, you probably need about 4,000 MW of additional capability in 2020 that is somehow fast start able, inflexible capability, on top of the imbedded expected resources at the time. So the resources that are already expected to be there are kind of your base.

CHAIRMAN WEISENMILLER: Okay, I guess what I was trying to get to, some of our existing steam boilers take like, say, 20 hours to start up and I'm assuming you're looking for more like 10 or 20 minutes on the fast start?

MR. ROTHLEDER: Fast start would be something in the 10 to, well, 10 to one-hour range would be ideal, something you could get started within the hour. We have capability of looking over up to five or six hours, but the shorter the time period is, the better off you are in terms of being responsive to the changing conditions.

MR. VIDAVER: In your first presentation, you talked about augmenting market mechanisms to increase the flexibility of the existing fleet, and you discussed a couple of ways it could be done, for example, intra-hour scheduling of imports, etc. Are there any other efforts under way at the ISO?

COMMISSIONER PETERMAN: Mr. Vidaver, could I ask you to say that question again louder? Because I can barely hear you.

MR. VIDAVER: I apologize.

COMMISSIONER PETERMAN: Okay.

MR. VIDAVER: In his first presentation, Mark talked about changing protocols to get more flexibility out of the existing fleet, and we talked at length about intra-hour scheduling of imports. I'm asking if there are other things going on at the ISO which are designed to increase flexibility out of the existing fleet, and he also mentioned that they are trying to incorporate operating requirements into resource adequacy and procurement, and I wonder if you could talk about those briefly.

MR. ROTHLEDER: So in terms of -- we are looking at other products and we've introduce a flexible ramping product that does, in addition to our reserve require us to maintain a certain amount of five-minute ramp flexible capability that is basically committed and on-line. That is a new service that we are compensating those resources, trying to do it at a marginal price. We will be evolving that product to be biddable products, where you can actually bid in for that capacity on a daily basis.

We are revamping and enhancing our regulation capacity, so to incent faster resources, expand the pool of technologies that can participate in regulation, and so that will help shore up the regulation and expand the fleet that can provide regulation.

We've done studies around frequency response, we don't have a frequency response product at this point. I think the first step would be whether we need to at least monitor and maybe put some kind of constraint around management of the fleet to ensure that there's a certain amount of committed unloaded capacity that can meet the frequency response at any given time. Other things that may be looked at in the future, voltage control and those types of services, that's something for the future.

In terms of the longer term, getting outside the daily operational, we are looking at flexible capacity products whereby -- and enhancing the resource adequacy with a procurement process to consider operational characteristics. I know we think that, if you enhance those procurement processes, you will get a fleet that is not just capacity capable, but flexible capable, that you need. That cannot just be done on the spot markets with market products, on the spot price. You need some kind of forward looking capacity procurement mechanisms to do that, and we believe that would be necessary.

COMMISSIONER PETERMAN: I'll just say, when we do hear from the other panelists, I would be interested in hearing your responses to whether these products that Mark has laid out will be sufficient to incentivize you all to provide these products to the market. Commissioner Simon, do you have a question?

COMMISSIONER SIMON: Yes, first, I want to thank Commissioner Peterman and Chairman Weisenmiller for this, I think, very important topic that we've had dialogue on, and I'm definitely looking forward to hearing the other presenters. I did have a question.

Understanding the amount of fuel switching that will occur, both for base load and peak in the region, are you getting an indication from generators that, in terms of what will be needed for various products to maintain the reliability, that the demand for these technologies could create any type of shortage or constraint in terms of the size of turbines that will be needed within the region, you know, for generation purposes? Because, particularly in these coal states, many of them within the WECC, I take it, will see a move towards natural gas by way of the predicted prices and reserves, so I'm just curious, are we -- and then you have this going on in a global basis, as well, by way of shale gas and horizontal hydrologic fracking. Is that a legitimate concern?

MR. ROTHLEDER: I think it is a legitimate concern. I think how the mix of resources outside of California in the coal and the gas are used, and I think being able to use those resources in a more flexible way is something that is being discussed, and I think needs to be discussed more, especially, as I indicated earlier, if we get into over-generation conditions in California where we're doing large amounts of an export, cycling of those resources external to California may be a necessary part of the solution. Whether those coal resources will really cycle, or whether they move towards a gas resource that can cycle more frequently, that may be part of the solution that needs to be kind of considered much more.

CHAIRMAN WEISENMILLER: Yeah. Mark, in terms of my follow-up question, the old paradigm is pretty much load, resource, balance, and it looks like the new paradigm we're looking for is much more an operational mix of characteristics; and I was trying to figure out, in terms of if any of the other regions in their procurement process, reflect that need to build up a stack of resources with the right characteristics.

MR. ROTHLEDER: From the forums I participate in, it seems to be a discussion that is happening more frequently across the West. I think there's an expectation that the energy itself, while still an important product on the margin, may be decreasing somewhat in its value, but there's the operational characteristics which will be increasing potentially in value. Whether they're offsetting, whether you can do that in the spot market alone, is really very, I think, questionable. There may be other mechanisms necessary to ensure that that flexibility is there.

MR. VIDAVER: Well, I can imagine that the owners of the existing fleet would have comments on what you've just said, and we have Mark J. Smith from Calpine here to probably comment at length on that, what Mark has just said.

MR. SMITH: There is much to speak of, actually. Yes.

COMMISSIONER PETERMAN: And if you would provide some context quickly about the size of the fleet that Calpine has, and just the role in California to date?

MR. SMITH: Absolutely. Thank you,

Commissioners, for inviting Calpine to come and speak. Calpine owns and operates about 6,000 MW of generation within the state, the majority of which is highly efficient, flexible, combined cycle power plants that have vintages of six to 10 or 12 years old. We also own a fairly large fleet of peaking resources that are fully contracted currently to Pacific Gas & Electric. So, David, do you want me to respond to Mark's comments, or launch forward on my presentation?

MR. VIDAVER: I assumed you would want to say something about --

MR. SMITH: Mark and I agree on many many points, probably reflecting back on what he said, one of the primary points is that the ISO is taking, I think, dramatic and positive steps to identify the needs of higher penetrations of renewables, the needs that are needed for compensating resources, and attempting to identify both what the incentives would be to offer incremental flexibility, and what the disincentives are within their current market to offering that same flexibility.

And some of the things that he didn't mention that the ISO is participating in, and that Calpine has been very supportive of, is focusing in on some of the disincentives, things like the way costs are recovered through bid cost recovery, it's a detail, but it's an important detail to offer incremental flexibility. The price ranges with which bidders are able to bid, particularly decrement energy, is an important issue that the ISO is addressing, to give us more flexibility. They're also addressing, might I say a bit indirectly, a prevalent bidding practice in California called self scheduling, it's an opportunity for generating resources to essentially say, "I'm going to run wherever I want to run, and you can't reduce me below that." It says, "I'm a price taker, I'll pay whatever the market clears, but I'm going to run my unit at self-scheduling." They're creating a lot of disincentives to self-scheduling to try to get people to put in economic bids to expose the inherent flexibility of the machines. Okay?

So with that said, I think the ISO is taking many positive steps to move forward. I would say the one thing that has been touched on a little bit this morning, and Mark touched on it a little bit, and Chairman Weisenmiller, you touched on it also, is the fact that the existing fleet is probably the lowest cost resource available for you to increment the flexibility of the system, that is, the existing fleet of combined cycles, 10,000 or 12,000 MW, including Calpine zone fleet, is probably the low hanging fruit in this market. It's the easiest and probably the quickest from the standpoint of capital investment, permitting, and from decision to implementation, the quickest way to get to incremental flexibility.

That existing fleet -- and I'm sure that the folks from Siemens and other folks will talk about -- that existing fleet with investments can probably fairly simply and reliably increase its ramp rate by an order of magnitude, probably double it. It can but its start time probably in half with certain investments, and it can reduce the overall cycle time, which is something that we didn't talk about, but it's probably pretty critical in being able to manage highly frequent and variable loads, it can but its overall cycle time and, therefore, cost pretty substantially.

Now if those kinds of investments -- again, I think Dr. Marini - is that how to pronounce your name -- will be addressing it specifically, but combined cycles that you've permitted were designed primarily as intermediate or baseload machines, and the technology -- I'm going to put this as simply as I can, and the doctor will probably go much more complicated, but it combines two forms of generation, it couples two forms of generation in one to squeeze as much capacity and energy out of a unit of natural gas as possible. And those two components, the first end of it is a gas turbine, not unlike that which you take off in an airplane often, right? It's a very fast reacting, very fast ramp rate. I mean, think of the ramp rate when you're on the take off, or a landing, very quick machines. But that's coupled to a steam generator, so the exhaust from that very fast gas turbine goes into a boiler and then eventually into a steam generator, and it's that back end which currently slows down the combined cycles -- it wasn't an issue when you expected these machines were going to run day in and day out without cycling, when they were going to run as base load machines or intermediate machines. So a lot of the investment de-couple -- to the existing machines -- could de-couple the gas turbines from the steam turbines, and we can talk about a temporators or quenching or blankets or auxiliary boilers, all as ways to get to that essentially de-coupling, but those are fairly minor investments, and I'm talking about single digit percentages of replacement costs, okay? So somewhere maybe seven to nine to maybe up to 10 percent of the replacement cost you put into an existing facility, double the ramp rate, and cut the start time in half, reduce the overall cycle time. Low hanging fruit that we absolutely ought to correct

Now, Commissioner Peterman, to your direct question, which is what do we have to do to get there. Okay? I brought one slide and one slide only, and it's not even mine. The slide that I brought belongs to the Department of Market Monitoring at the California ISO, and each year they look backwards at the revenues that were thrown off of their markets to try to figure out how much revenue a typical combined cycle generator would capture to the current markets. And if you look at the slide in 2011, which is the latest data that they've analyzed, you can see that the current ISO markets throw off roughly $20.00 per KW year of revenues specifically from their energy and ancillary services markets. That compares to the cost, a levelized cost, of a combined cycle unit in the range of $200 a KW year. No rational business person is going to make an incremental investment in capacity when you're confronted with costs like this. Your own numbers from the CEC show that the going forward cost, that is, things like ANG and property taxes, are about $50.00 a KW hour.

So you can see that, without an incremental payment of some kind, without an incremental investment of some sort, further investments will not be recovered or could not be recovered. Now, what this doesn't include, Commissioner Simon, is your resource adequacy payment, but it's capped at $40.00 per KW year, it's not capped, the utilities can come to you and say it's too much at $40.00 a KW year. So, even if you add that on to the existing ISO payments, you're roughly at your going forward costs, and it's irrational to make investments.

So, Commissioner Peterman, what do we need? We need a different form of compensation. We need incremental compensation. Mark Rothleder is working on short-term products that will help to get us there, but a short-term market is never going to justify a capital investment, at least in today's world in California. What we need is to translate those short-term products into long-term demand for products, long-term demand for the kind of attributes that we want in this market, and then offer contracting opportunities so that I, as a generator, can look out three or four years and know what my revenue expectation is going to be, know what my return on an incremental investment is going to be, and make a rational decision.

Now, I think we're headed in that direction, at least I optimistically hope that we're headed in that direction. Commissioner Simon, it's a bit of a tangled web at your Commission between the LTPP tracks and the RA tracks, we're hoping to get a line of sight through those to get to a forward procurement requirement; that will help dramatically, we think. We also think that, in addition to a forward procurement requirement, if we get to a point where it's attribute-based, where it says, we need ramping capability, we need fast starts, and we need other attributes that we'll get to a point where it'll be rationally economic for us to make these kinds of investments.

So that's a long long answer, I think. My whole presentation, my entire slide deck, in response to Mr. Rothleder, and I think that I'll probably have more things to say as the panel wears on, if that's all right, David. Commissioners, thank you. I would be happy to answer any questions based on what I --

COMMISSIONER PETERMAN: Great, because I've got a couple -- a couple questions. So this chart, the Levelized fixed cost target, this is a new plant, is that correct?

MR. SMITH: Yes, that would be the cost of a new plant, right.

COMMISSIONER PETERMAN: Okay, so an existing plant, you would position that around -- well, our studies say $50.00, but I was just --

MR. SMITH: Right, you're -- I'm sorry, Commissioner. Your studies show that the going forward costs -- so that ignores all capital recovery, all return on equity, all costs of debt, okay, just the going forward costs would be $50.00.

COMMISSIONER PETERMAN: And do you have a ballpark estimate if you are looking at a typical plant in terms of capital cost recovery and such, what that would be?

MR. SMITH: I don't, it depends on the individual unit and how old the unit is and what its depreciation schedule is, and how much of it has been depreciated.

CHAIRMAN WEISENMILLER: A couple questions. I think, first, just for context for people, oftentimes we talk about the gas plants, although there are at least three different types, there's the peakers, which you have -- Calpine has some, but anyway, it's a much different story than the hypothetical combined cycle. We had the old steam plants, which a lot are sort of LBJ vintage, which eventually will be repowered in some fashion, but very low operating range. And then we have the combined cycles, most of which are the newer ones, which, again, represent the Calpine fleet. So we're talking just about those newer combined cycles in this context. And so, looking at those, again, the interesting question, as you indicated, most of these were built assuming like an 80 percent capacity factor, and obviously most of them, I think, are operating more at 50 percent. And presumably, there are investments that should be made in those plants to give those greater operational flexibility. Do you have a ballpark sense of what those are in terms of magnitude? And then, the other question is, would you make any of those investments based upon RA contracts which are essentially year to year?

MR. SMITH: Thank you, Mr. Chairman. Let me start with the ballpark estimates. Converting a combined cycle, a base load combined cycle to a peaking plant is probably not feasible, but there's something in the middle where we can, as I said, pretty substantially reduce our start time, reduce our overall cycle time. A peaking plant can start -- our peaking plants can start in 10 minutes and they would have a minimum run time of about an hour, maybe two hours, before they can shut down, and that's really driven by the thermal stresses without those machines.

Is it possible to get a combined cycle plant there? An existing combined cycle plant there? Maybe. As I said, the key is de-coupling the steam side from the gas turbine side, to get quick starts and to get ramping capability. And again, I think somewhere in the range of, you know, seven to 10 percent of that $200.00 per kilowatt year number is about what you can do, maybe $50 million, something like that, you could probably get quite a bit of incremental both ramping capability and reduced start time.

Now, the next question I think you asked was a bit leading and I appreciate it. And the question was, would we make an investment based on the current annual RA program. And let me just put that in context. There's a substantial portion of our fleet today, as it sits, on June 11th, that doesn't have contracts beginning January 1st, 2013. If I don't know six months forward, or by the time RA contracts are completed for 2013, in October, maybe three months before the fact, whether I'm going to have contracts and revenues, I'm going to be very disinclined to make an incremental capital investment, especially in the current environment of market clearing prices. That's why I argue a longer term forward commitment makes sense, and ideally one that is attribute-based.

COMMISSIONER SIMON: Yes, thank you, Mark. Two questions, 1) in terms of your cost estimates, does this include once-through cooling restrictions that may imply and/or additional carbon cost, that being sequestration?

MR. SMITH: Thank you for asking that question because it goes back to Chairman Weisenmiller's context, Calpine doesn't own any once-through cooling units, so that cost estimate is really overnight capital costs that would be associated with the kinds of incremental investments we would need to make. No, it wouldn't also include GHG costs, or sequestration cost. It's an overnight capital cost.

COMMISSIONER SIMON: As Calpine has probably noted, both Colorado and Oklahoma have embraced long-term procurement contracts to lock in on current price levels. Does that provide -- even though understanding that's pass-through, but does that provide any level of certainty that would better integrate LTPP and RA?

MR. SMITH: Well, quite honestly, I'm not familiar with Colorado's structure, but let me answer the question more generically. With a commitment to a capacity revenue, and that doesn't necessarily not lock in prices, Commissioner, because gas price volatility could occur, as well, so what that essentially is, is a commitment to make the machine available and meet whatever attributes and design standards the off-taker would like. A commitment of three to five years is going to get the investments, probably. As a matter of fact, for some of the existing units that we have, we have upgraded turbines as a direct result of having term commitments on them.

CHAIRMAN WEISENMILLER: I guess, Mark, since you're here, I asked the other two questions on which may be leading or not, but at this point in LTPP, can any of the existing plants bid for long-term contracts?

MR. SMITH: No, the existing plant are prohibited from bidding into the PUC's -- or, the Utilities' RFO's that are a result of the 10-year forward LTPP construct and, as a matter of fact, I would say that, if there's one thing the California Energy Commission could do, it's to not assume that uncontracted units going forward are going to be available, we have seen that in spades with the unfortunate case of our Sutter plant.

CHAIRMAN WEISENMILLER: Yeah, I tend to view Sutter as sort of the canary in the coalmine in terms of the existing gas leaks, so I guess the question is how many of your existing plants as they get de-contracted are going to have financial challenges?

MR. SMITH: Well, I think you can reflect on the slide that I've shown here to indicate that, without adequate additional compensation, if gas prices stay where they're at, or even if they modestly increase over the next couple of years, the challenges to existing assets will rise. And the number of megawatts, and I think there's 10 or 12,000 MW, not just Calpine's fleet, of combined cycles that would be in a similar position.

COMMISSIONER PETERMAN: Just a follow-up question for both Marks, perhaps. You know, looking at this slide, acknowledging that the need -- the greater benefit of turning the short-term compensation to longer-term stream, but just taking one year in itself, with some of the projects that you are considering at the ISO, Mark, you know, how much does that reduce the difference between the revenue needs and currently what's available?

MR. ROTHLEDER: The short -- if we're talking about the short-term products, things like flexible ramping, it's a small increment on top of these, so it's meant to manage the fleet, it's meant to be an efficient way to manage the fleet that you have, but I’m not sure if it -- and it may provide some incentives for a fleet that exists to maybe put some investment into some incremental enhancements to extract some of the flexibility, but it's not in itself going to resolve these differences.

COMMISSIONER PETERMAN: Thank you.

MR. VIDAVER: Well, we have new combined cycles and now we have very very very new combined cycles and other gas turbines, and there has been no original equipment manufacturer that has been more successful in getting its wares placed in California in the past couple of years than Siemens, so we've asked a representative from Siemens to come in and talk about what new gas can do and what the obstacles are in the way of new gas doing even more.

DR. MARINI: Hello. I'm Bonnie Marini. Thank you for having me here today and I will try to address some of the questions that you brought up, but most of my presentation is really about the capabilities of our new gas turbines and we're continuing to grow those capabilities over time. So if we could go to the next slide?

Siemens has been working on developing flexible combined cycle for California and for integrating renewables -- okay, can you hear me better now? Siemens has been working on developing flexible combined cycles to integrate renewables for more than a decade now. We looked at the situation and saw some of the challenges that were coming in the future and started focusing our development on the bottoming cycle, as well as the gas turbine, and I think Mr. Smith had stated it well, that a lot of the challenges with getting combined cycles to move is not with the gas turbine itself, but is with the balance of plant and designing it to move quickly.

We have three kinds of products that move very flexibly to integrate with renewables, and examples of them are on the slide in front. And the middle one is really a unique product, we call that our Flex-Plant 10, and that product was really born out of a desire to make a peaking plant that could meet emissions requirements because a simple cycle gas turbine has very high exhaust temperature and so you can't run that exhaust flow through a conventional catalytic reducer, so we wanted to reduce the temperature of the exhaust, and to do that we developed a very flexible simplified bottoming cycle to enable the exhaust energy to come out, go through an SCR, and get the whole plant down to 2 ppm NO_x emissions compliance. And in doing that, we worked with boiler manufacturers to develop capabilities to get boilers that would ramp up and down very quickly and enable that plant to move like a simple cycle. That plant was designed and will deliver 150 megawatts to the grid in 10 minutes, so it has that flexible capability that peaking plants do, but adding that bottoming cycle gave it a lot of extra benefits, it got us down to a very low emissions compliance number, it makes the plant more efficient than any simple cycle plant would be, even a very high efficiency gas turbine would not be nearly as efficient, as even a simplified combined cycle, so you get better efficiency, it uses a tremendous amount of less water than most simple cycle options, and so you add all these capabilities into a combined cycle and you have a peaking combined cycle application. So that was really one of the first entries into that concept in getting combined cycles that could be used for peaking capability.

We started bringing those capabilities into our more conventional very high efficiency combined cycles, so a standard three pressure, reheat, high efficiency combined cycle. And on the right you see an example of that with Lodi Energy Center, that's what we call a Flex-Plant 30, and that's a high efficiency combined cycle that still can ramp and has a lot of the capabilities that we had in the smaller combined cycle to start quickly and ramp quickly, load follow quickly. When we first developed that plant, it did not start as quickly as a Flex-Plant can, but I'll talk a little bit about some recent developments, and we've been advancing that capability as we go.

And on the left is a different approach to meeting the flexibility capabilities for integrating renewable, and this is actually a simple cycle plant, but this plant uses a dilution SCR, so Marsh Landing, our simple cycles with the dilution SCR, and when that plant went under contract, Siemens actually did not offer a dilution SCR, but we have added that to our portfolio and we're continuing to work to add capabilities that we see would help enhance these renewables and being able to integrate them onto the grid. And I'll talk a little bit about those capabilities going forward. If you could click, you can see the pictures of the real facilities and where they are in construction. Some of those pictures are a little older than others.

But we continue to work to get low cost, clean generation for a combined cycle and get the flexible fast moving generation that's needed to integrate with renewables. Next slide, please. And you can click again.

So basically, we see the place for gas generation to be to marry these technologies that are out there in the marketplace, so you have very low flexibility, base load generation, and as has been brought up several times, this was really how everything was operating in the past, everything moved rather slowly, so there really wasn't a huge need for combined cycles to move quickly. But with the introduction of large portfolios of non-dispatchable MW of renewables that will ramp up and down quickly, there's the need for these combined cycles to move flexibly, to ramp up and down. And so we designed the features into our plants to do a lot of the things that we've heard before -- they need to start fast. And so these plants are all designed to put 150 MW on the grid in 10 minutes.

And I just wanted to mention, these plants I've shown pictures of are all with our F Class gas turbine, but Siemens actually offers three different sizes of gas turbines for different needs that fit into these kinds of plants. We have E class engines which start in about 110 MW; F classes are about 200, and we have H class that are about 275 MW. So we have different sizes that all leverage these capabilities, depending on the need of the particular facility. They will load follow up and down -- quickly. Now, one of the things in technology space that we combine here, that aren't really combinable is starting fast and ramping fast, they're two separate capabilities. I think in the service fleet, this is something where capabilities are easier to add in one than the other, so starting fast is actually a harder thing for a boiler; it's the kind of thing that the boiler has to be designed for in the first place. But ramping fast and being able to load follow is something that is a situation with modifying your bottoming cycle, adding some capabilities, and some of those things can be done in existing cycles and upgraded to allow cycles to load follow once they're warm.

And for a two on one combined cycle, these cycles can load follow at more than 75 MW a minute. And I think one of the interesting things to look at when you're looking at this very large renewable portfolio is I think historically people looked at small generation to help firm that capacity, but if you have a large number of MW you want to move, being able to do it with a large facility helps you because you can move a lot of MW at once, and as was mentioned before, ramping up isn't the only challenge, ramping down is a big challenge, and shutting down a small facility quickly and controllably is somewhat more difficult than ramping down a large facility with the same number of megawatts in a controlled fashion. So we believe that some of these large combined cycles with their ability to use the top of their cycle to move up and down will be very helpful in integrating renewables.

We've also added the capability to run them at much lower loads and run them efficiently at much lower loads, so the gas turbines can go to lower loads at high efficiency, and they can operate between the low load and the high load very flexibly during the day.

COMMISSIONER PETERMAN: Dr. Marini, may I just interject, just so I can keep similar numbers on this, my same page for my notes, so the average combined cycle currently operating in California, what would the comparable numbers be in terms of how much can ramp in a certain amount of minutes, and the load followings, just acknowledging that there's some variation, I don't know if Mark maybe has a better sense to try and get a gauge.

DR. MARINI: There definitely is some variation from plant to plant. Maybe you have some numbers for the Calpine units?

MR. SMITH: I think, Commissioner, it really depends -- I'm sorry to say that it depends. It depends on the load level that the machine is at, in other words, if you're at the top end of the load curve, in other words, within say 10 percent of the maximum output of the machine, the ramp rate is going to be pretty slow, and it's going to be slow because most of that ramp rate is coming from that slow moving steam turbine. If you're below that, say in P min 2 X 1, so you have both gas turbines running and the steam turbine is coupled to it, you can move very quickly for the next, you know, say an existing plant might be able to move for a small range at 40 MW a minute, maybe. Now, that's not what would be reflected in the ISO's data because we have to average it over a longer period in order to show what the incremental rate is.

COMMISSIONER PETERMAN: So under ideal circumstances, most optimistic prediction would be about 40 MW a minute in terms of load following? And then what would be the start capacity?

MR. SMITH: Again, in a 2 X 1 combined cycle mode, starting at P min, and that's what our typical ancillary services tests will show. So there's a strong capability from the existing machines. Now, I'm sorry, your second question was?

COMMISSONER PETERMAN: Well, I was just looking at both of these statistics on this slide, so just --

MR. SMITH: The start times?

COMMISSIONER PETERMAN: The start time.

MR. SMITH: Yeah, I would say that our typical start time from a hot configuration is 90 minutes.

COMMISSIONER PETERMAN: Okay.

MR. SMITH: So, in other words, if you've been off-line less than a few hours, you can start in 90 minutes, a combined cycle, a little bit longer as the machine cools down more and more.

COMMISSIONER PETERMAN: Thank you very much.

MR. SMITH: Sure.

DR. MARINI: I think, in addition to the rate at which the machines can move, one or the other capabilities that we've improved is the level that you can turn the machines down to. And that's a feature that is important, as well, how far you can turn the whole combined cycle down. We've gone to levels as low as 40 percent load on the newest combined cycles, which gives you a lot of MWs to move up and down.

Now, while we're doing all this, we also have to maintain all the capabilities that the plants had in the first place, high efficiency, low water usage, low emissions. And recently we've seen people having an expectation that they're going to be ramping very frequently. In the past, it was assumed that you would ramp infrequently, so having an emissions excursion while you were ramping wasn't really an issue because it would be averaged out, it happened infrequently. But now we see an expectation that this will be happening very frequently, and Siemens has just introduced the capability to maintain low No_x and CO emissions will the combined cycles are ramping. And we call that Clean-Ramp, I'll talk a little bit more about that in a coming slide. Next slide, please.

So combined cycles, one of the reasons we're focusing on combined cycles is clearly there's an advantage in efficiency, the cost of generation, the cost per MW is lower with the combined cycle. The other thing that comes out of that directly is that you're generating less greenhouse gasses if the efficiency of your generation is higher, so it helps both in cost and environmentally.

So this slide shows a little bit about how this cycle differs from what had happened in the past. So the green line on the right is how a traditional combined cycle would have started up, so some of the cycles that were designed a decade ago, they would ramp up to a low level, they would hold at that level for some warming and pre-warming of some of the bottoming cycle equipment, they would take another step, or two, or three, to get to the top of the combined cycle. Now what we do is we start the gas turbine up to base load almost immediately, so we'll sync for five minutes, we'll ramp it up to base load, you see that gas turbine line on the left, and we're able to start the bottoming cycle quicker and faster, which is that steam turbine line you see in the middle, and the Flex-Plant line is how much generation we can get now with this new technology and the new capability. So you get more megawatts faster, and the other thing you do is you generate less emissions because, when the gas turbine is at very low load, it's putting off a lot of CO. So it helps you in several different ways.

I mentioned the clean ramps, so this is a new system that Siemens just started offering in December of 2012, we just introduced this system, and it is a system that maintains stack emissions while you're ramping, and right now, Siemens is able to guarantee the NO_x and CO to be within emissions compliance while you're ramping, and we're currently working on some testing and finalization to be able to guarantee ammonia slip while you're ramping the system. Next.

Okay, so basically, in conclusion, the Flex-Plants are combining some features that we feel are very useful and valuable for renewable integration, it's got a huge operating window, so you can go from low load to high load, it has very high efficiency, it's got a low cost of generation and low greenhouse gases, and the low emissions and the ramping capability with the clean ramp, so these capabilities are things we're focusing on and trying to continue to develop with our combined cycles. And the last slide, please?

So there was as question on what challenges remain and I think there are basically two challenges, and one we've talked about a bit before, is how to get people to down select these technologies, that right now there is just little pay-off in many regions for flexibility and adding these capabilities to the cycle. And then the other challenge we see here in California is that the entire process for putting in and choosing these cycles is very long, and that adds some challenges to implementing the latest technologies, there's a lag between the development and availability of the technology and when it can be implemented here in California. And also, there are challenges in costing and pricing and being able to maintain a cost level, or offer a cost that would be good for the duration of time that it takes to go from first introduction until the plant is purchased and implemented. Thank you.

COMMISSIONER PETERMAN: Thank you. Following up on an earlier question by Commissioner Simon, what's the demand you've seen for these new products in California and in the West at large? And also, just in regards to timing, how quickly could we do some of the retrofitting suggestions that you mentioned? Acknowledging that, perhaps, more on the regulatory end will be the time delay than on the equipment end, but it's good to have a sense of how long it takes to get this new equipment.

DR. MARINI: Could you please clarify the first question?

COMMISSIONER PETERMAN: So the first -- so Commissioner Simon was asking you earlier, I think we've both been hearing within the WECC, current coal plant operators are considering transitioning to natural gas plants, and so wondering if you're seeing a demand for these new types of plants outside of California, and also what the demand you're seeing within California, as well?

DR. MARINI: Well, you know, the market is so difficult to predict, sometimes we say we're in the crystal ball business trying to figure out what's going to happen next. I think there's a general expectation that there is going to be a big boom in demand for gas turbine generation in the coming years, but it's very difficult to predict which year that's actually going to happen. I think historically we've seen that the U.S. market, instead of being smoothly developing and ramping up and down, is happening in huge peaks and valleys in demand, and I mean, there's a lot of information being requested, there are a lot of customers asking for details and starting to develop their plans to go forward, but it's uncertain. We do expect that there's going to be a huge peak. But no one knows for sure.

COMMISSIONER PETERMAN: So would it be fair to say that we have yet to see the on-the-ground experience yet with these faster, more efficient plants?

DR. MARINI: No, in fact, in one of the previous presentations, they were talking about the renewable integration in Germany and our benchmark plan for our 8000H is in Germany, and that plant has these fast start capabilities, it's a single shaft one on one combined cycle that produces 500 MW and it is on the grid every morning in half an hour. It shuts down overnight every day, and it's been operating that way for almost two years now.

CHAIRMAN WEISENMILLER: A couple questions. I guess, on the timeline for new projects, I was wondering if, Mark, if you could submit that chart that ISO developed in August in the record here. I think there's an ISO chart that was talking about sort of an eight-year timeline? Yeah. And in terms of -- in your slide 5 on the timescale for stuff, at this point, I'm just trying to -- if you can give us a rough sense of what the timeline looks like, the operational characteristics?

DR. MARINI: Oh, to start up the plant?

CHAIRMAN WEISENMILLER: Well, yeah, just go back to slide 5 for a second. That one. Okay, so the bottom access, roughly what's the timescale on that?

DR. MARINI: Well, there are two ways to start up a Flex-Plant, and if you start the gas turbine as fast as possible, then you can get the bottoming cycle up in less than an hour. And if you start it at a slightly slower ramp rate, you can get the whole cycle up in under 45 minutes.

CHAIRMAN WEISENMILLER: Okay, thanks.

DR. MARINI: You're welcome.

COMMISSIONER SIMON: Yes, I'm trying to reconcile the presentation so far. Mr. Smith, your contention is that, under the existing fleet, with upgrades, the demand required for 33 percent and the variability in fast ramp needs will, from Calpine's perspective, the existing fleet can cover Calpine's commitment to that scenario.

MR. SMITH: Commissioner Simon, what I would say is that I think it's the low hanging fruit, it's the cheapest source of incremental variability or flexibility services. I don't know if Calpine's fleet alone could meet all of the demands, or even the entire combined cycle fleet as it exists today could meet the growing demands for flexibility. I know the ISO has spent an enormous amount of time studying that, but what I do know is that it's most likely the cheapest source, one of the cheapest sources, of incremental capacity.

COMMISSIONER SIMON: And to roll over to Dr. Marini, and I'll expand a little beyond the WECC and even the U.S., when we're looking at, again, fuel switching, and the demand for fast ramp products, the current supply, or the projected supply of turbines can meet the demands that California will have under the 33 percent scenario?

DR. MARINI: That’s a rather difficult question to answer. I actually -- I don't exactly know how to answer that question. I mean, it depends how the timing is and how everyone spaces out their orders for gas turbines. Certainly, there is a limit on capacity, on how many gas turbines can we produce, and we do anticipate that we're going to see it peak again, where the demand may out strip the supply capability, but it's very hard to say. We do -- I'm responsible for looking at the market in 60 Hz globally and there are different regions in that market that are very very active, and regions that are less active, so -- in many of those regions, this fast ramp capability is important, but really what's limiting the lead time or availability of these plants is the gas turbine. And it's the same gas turbine, whether we configure it in a very flexible bottoming cycle, or in a less flexible bottoming cycle for a region that doesn't need that kind of capability, so it's really the number of gas turbines that the company can produce at any given time and what the demand is in terms of orders. So I do think there's some risks that we're going to get to a capacity limit, but, no, one of the reasons that we haven't gotten there, that there haven't been purchases, of course, at the volumes that we would have predicted in the past, is because of the recession and the reduction in load demand in some regions, but we're definitely seeing a trend that people who are replacing power, or adding power, are going to gas supply because the cost of fuel is low. And we see studies that show that availability will be expanding, that there are expectations that the regions of the world will have the same kinds of findings that we had here in the U.S.

COMMISSIONER SIMON: To Mr. Rothleder, taking both of these accounts into effect -- you know, this kind of reminds me -- because I deal with this issue all the time, as well as my colleagues here on -- my own attempt to forecast for purposes of my vote, and particularly the cost to ratepayers, and it reminds me of the Bill Cosby show where the Huxtables have hired a contractor to do work around the house, and every time Cliff Huxtable asks the contractor the cost, or what is this, he would answer, "Well, it depends." And that seems to be the overriding response. But, again, Mr. Rothleder, taking this into account, and by way of the CAISO's projections, do we see fast ramp technology and availability of these technologies, in terms of global demand, and California is clearly a part of -- a major part of that global demand -- are there any anticipated supply concerns from the ISO's perspective?

MR. ROTHLEDER: I can't speak to the capacity to create the turbines and stuff. I think our concern is that, do we have the market structures, the policy structures in place, to properly determine what that demand should be and act on those needs? Because if that demand doesn't -- if that demand isn't created for whatever technology, then it won't be developed. If we can get that demand created to meet the operational needs in the timeframe that it's needed, over the next eight to 10 years, I think then you have -- if you stage it correctly, you can deal with things like existing resources that maybe are shorter lead time, lower cost options in the short-term, while you get ready for those potentially higher cost, higher quantity needs as you take on the once-through cool change-out. That's in the 2018-2020 time period. So I think you have to start asking now to create and stage that plan of demand and not wait because, if you wait, then your demand and your options are very limited at the end, and maybe even more costly. So I think staging it, planning it out now, is the time we have to act.

MR. SMITH: If I could respond to that, just for a moment. Again, this is Mark Smith of Calpine. In a world of such dramatic uncertainty, particularly cost uncertainty, it seems to me the best solution would be to create a market where people can bid what their true costs are, and allow that market to find a way to meet the demands that have been expressed, as Mr. Rothleder says, through the functions of competition. And what that means is we need to go out into some future time period and identify what those products are, what those attributes are, what those needs are, and allow everyone to express what their indifference price is, whether that be demand side, incremental investments in existing facilities, brand new facilities, alternatives maybe to once-through cooling units, that don't involve brand new power plants. Let them express all alternatives, and through a market, and that seems to be the best way, at least from my perspective, to find the solution without having a Huxtable omniscience knowing all prices at all times, and all costs at all times.

COMMISSIONER SIMON: So you're basically referencing a restructuring -- a market restructuring to increase competitive choices when you're speaking of competition?

MR. SMITH: Yes.

COMMISSIONER PETERMAN: Thank you.

MR. SMITH: Thank you.

COMMISSIONER PETERMAN: Thank you for that and for -- I think we've got on the record that you're interested in an attribute-based system. Cognizant of the fact that we haven't heard from our two other panelists, so let's hear from them. And I know we're running past time, I'm going to ask for everyone's indulgence, if you need to step out, leave, do whatever, feel free, it's an open hearing. But I want to make sure -- this is a good discussion and we're going to go a little bit longer in order to capture everything, to the extent possible.

MR. VIDAVER: Siemens is not the only entity staring into a crystal ball trying to figure out what natural resources are going to be demanded. The project developer is faced with a menu of resources presented by Siemens, among others, that offer different characteristics and different costs. The developer, in turn, is staring at a crystal ball that is whichever entity is evaluating the resource that the developer coughs up in an RFO. We're pleased to have today John Kistle with -- I believe, is it Allegany Energy Services?

MR. KISTLE: AES.

MR. VIDAVER: AES, okay --

MR. KISTLE: Which is not Allegany.

MR. VIDAVER: Oh, my apologies. AES Energy, which owns and operates existing once-through cooled resources in the Los Angeles Basin, and I understand will be coming in to talk to the Energy Commission about new resources at one or more of those facilities. So he is here to offer us the perspective of the project developer.

MR. KISTLE: Thank you. John Kistle, I've been with AES about 10 years, and in those 10 year, I've had an opportunity to work on a number of different generation businesses around the world. AES is a company of a little over 40,000 MW in 26 countries, and we have 4,200 MW here in California, specifically in the West L.A. Basin. Our units in L.A. are of the LBJ vintage, they are about 50 years old, they are gas-fired, they are once-through cooled, and they are exactly what needs to go away and be repowered.

So our challenge is really finding the right solution for our sites and a number of the attributes that have been discussed, as well as other economic and environmental considerations. I can state clearly, there is no shortage of solutions. There are many options available to us, there are proven gas turbine technologies, as Siemens has pointed out, that the gas turbine proper has been demonstrated in peaking applications for many many years, so our challenge is really coming up with the right gas turbine and right attributes and the right balanced plant design, this decoupled nature of the secondary cycle and facility.

I placed a slide here that helps us look at this a little differently. So many times we think about heat rate and the variable cost of generation, and then we think about the fixed cost to build the asset, and we don't think about where it's really going to run within the broad range of its turndown capabilities, the numbers of starts, and what truly drives the cost of energy on an asset. I've represented two different technologies here, one Bonnie has already discussed the Flex-Plant 10, and in this case I'm showing two Flex-Plant 10s and I'm trying to get ourselves somewhere around a 500 MW comparison to demonstrate that the aeroderivative peaker and the combined cycle rapid response have some very different considerations here. And what we see is this spread on heat rate really requires productivity, you have to be able to operate in a condition that allows you to extract some value of this heat rate. If you're operating in some off base condition, or off design condition, you can see that this heat rate benefit gets diluted very very quickly. And that's the point we're trying to make here at about 400 MW, or at about 200 MW, depending on the configuration when compared to an aeroderivative, there really isn't a lot of heat rate benefit. The environmental benefits start to degrade in these operating conditions. And that has been our biggest challenge. We can look at the static economics of a facility, but the dynamic economics of a facility have been very very difficult for us to forecast. Then, we consider, in addition to this notion of variable cost on fuel, what are the recoverable costs to be able to start? And we've found that start costs drive the economics significantly greater than the variable cost of fuel, especially if we're looking at a lot of cycling duty where we need two or three starts a day.

Mr. Rothleder's earlier slide that showed the two peaks with the renewable integration are exactly the case that we're thinking about -- two to three starts per day. What do the economics of an existing facility look like compared to something that is specifically valued for that type of operating environment? And that is really where the challenge resides for us now. There's not a lot of clarity available to what the system requirements are. We've come up with some targets, we've come up with some attributes, and although those attributes are indeed important, we understand that, they do not provide a substantial economic benefit to how we value the facility. So our objective is to find something that the system needs that still results in a relatively competitive cost of energy. We saw some numbers up earlier o $0.10 to $0.13 KW, we think we can get under that, but we need to make sure we're communicating what those iterations are in the system, or in the technology, or the limitations -- the appropriate limitations to be able to enable that. Next slide, please.

I have depicted here one of these solutions. Bonnie also mentioned an E class gas turbine, a technology that's been around for about 30 years, and here we look at a multi-state generator -- or a multi-stage generator, and start considering some of those attributes and the turndown capabilities. And this is a configuration here that could put about 300 to 360 MW on-line in 10 minutes, has a reasonably competitive heat rate, has about a 100 to 120 MW a minute ramp rate, and it's fairly economical to build. It has a fairly economical start cost. But is this heat rate and these off-case conditions acceptable? You know, economics, we can pursue on this, but if we don't find the appropriate iteration within the system to help us understand if this solution is going to work, we may be chasing the wrong dog up the tree in this case.

There was an earlier statement that the permitting process takes quite a long time, and I think we all understand that, and I'm not here to refute the permitting process. But the assumptions that go into the economics of something that we want to permit can change, and the dynamics of that are really what we're trying to chase down here, and we seek a forum where we're able to get some iterations on those dynamics to test the robustness of some of these solutions. We prefer not to be in a position where we are having to retrofit turbines in 10 years because some of these market conditions moved out of favor. We think we can test some of those solutions now. Internally, EAS has done that, but we would like to engage with other entities to help derive some of the robustness in these solutions.

I'd like to overlay this in the next slide to show you how it lines up with the existing choices that have been used in California. This type of configuration, by the way, the multi-stage generator, is prevalent in California, but it's very broadly used in the rest of the world, as well as the United States. Not a problem at all to go out and find the turbines and the technologies that enable this sort of solution.

There were a couple of questions about ramp rates and time integration and in the last slide I've tried to depict what some of these solutions can do for you. Last slide, please.

Here's a time stamp from initiating admission until about 350, 360 MW on-line, 10 minute, we have de-coupled the back end of the combined cycle configuration from the ability to ramp the gas turbines. A consideration, again, in the economics and the limitations, my job is to find the best economic choice for a number of these parameters, and there are plenty of technologies to do that. Some of the methodologies used to value a gas turbine move some of the variable costs into a fixed category by putting the penalty on the asset for a minimum amount of time that it would operate. And if we ran in a truly variable cost environment, we would be able to eliminate some of these fixed costs and look at what the true costs of dispatch in and out is and what the true cost of energy is, and remove some of these limitations from minimum on and off time. We've indeed gone through that exercise to, 1) drive a solution that is unlimited in the number of starts and stops that it will have, at least in the engineering there will be other environmental constraints, and then iterate on if that lower start cost makes sense, if a higher start cost can be burdened, and if the fixed or variable cost of energy is worth it in the end. And in these sort of iterations, we would like to go through in a number of forums that would be available, and I'd like to follow up with the CAISO on, as broader, how does the system react to that? What are the needs? Where are those needs being driven? And let's find a solution when we repower that enables that cost of energy solution rather than looking for constraints on existing assets or making something that's out there already out of market trying to get back into market, and I hope that's something that resonates with you folks.

COMMISSIONER PETERMAN: Thank you very much. One of the things I've been thinking about generally with this topic are the opportunities for co-location and to what extent companies are pursuing them, and since AES also does wind generation and other, PV and storage, etc., just wondered if you could speak to if you are co-locating some gas plants with some of these renewables, and yeah, just get your thoughts on that.

MR. KISTLE: No, we are not. The available land that we have for the existing assets is inadequate for additional solar or for wind, and in the areas where we are building solar and wind, that real estate is best used for that particular technology, we're not looking at co-locating gas turbine assets with those facilities. Now, there is an opportunity for energy storage -- battery storage, with wind and with solar, and yes, we are looking at that.

CHAIRMAN WEISENMILLER: My understanding is you do have a storage experiment on one of the gas plants in California at this stage and I just wanted to understand how that was working.

MR KISTLE: We had a small one MW battery on the Huntington Beach facility. The purpose for that was really to test the controls to allow the integration and the ramp capability of an energy storage system, which has been demonstrated, we've worked that out, and it's now being applied to larger scale projects.

CHAIRMAN WEISENMILLER: That's right, you have a larger scale, I guess, I'm trying to think, in West Virginia?

MR. KISTLE: There are several different energy storage projects that are going forward, I'm not familiar with all of those businesses and locations, so I can't comment to them specifically.

CHAIRMAN WEISENMILLER: It is interesting because, when you bought these assets, when Edison owned those, they used to typically, for their plants, they would start up about and shut down about six times a year, so certainly in the current regime, that's probably more like a weekly number than an annual number.

MR. KISTLE: A little bit more often than that.

MR. VIDAVER: Thank you. We'll now return to the notion of how the existing fleet can provide additional flexibility. We have a representative from Turbine Air Systems.

MR. PIERSON: Thank you, David. My name is Tom

Pierson. I'm the Founder and Chief Technology Officer of TAS Energy. I think my talk will dovetail very well with Dr. Marini and Mark Smith's. Basically, this is a technology that expands the flexibility and the quick response of existing or new combined cycle power plants.

So this technology will expand the -- call it the operating envelope -- of existing combined cycles by approximately 15 percent by adding this on the approximate top 18 opportunities in California, we estimate it could create an additional 1,500 MW of flexible power and that a cost of about $250 to $300 per KW, per incremental KW, if it's applied on a new combined cycle plant, or about $350 to $450 if it's a retrofit of an existing combined cycle plant. So it's roughly a third of the cost of adding an additional peaker. In addition, these flexible megawatts are generated at the same -- roughly the same -- heat rate as the combined cycle, so it's significantly better than what you would see with a peaker. It's also a very proven technology, there's roughly 400 turbines around the world that have turbine inlet cooling and not necessarily generation storage, which I'm mainly going to talk about, a little newer version of turbine inlet cooling.

The other advantage of these is they can be added very quickly, really, you can do it in less than a year, even on a retrofit basis, so it gives you a lot of flexibility in terms of adding flexibility into the Grid, and it's in nice increments of roughly 40 to 80 MW per retrofit, let's say if you're retrofitting a 500 MW two on one 7F combined cycle, which we would look at as kind of the classic case for integrating this technology, you're going to pick up roughly, you know, 65 plus MW in that plant and you're going to get a lot of flexibility, which we'll talk about. Again, at about a third of the cost, roughly half the emissions, of a peaker, but with, of course, no new transmission and no additional gas turbine maintenance because you're really utilizing the same gas turbine, it's just able to operate more flexibly.

So this is basically what all gas turbines look like as a function, the power is a function of the weather, and the nameplate of all gas turbines is defined as ISO, which is 59 degrees, so at 59 degrees, your 500 MW power plant does 500 MW. But when it gets hot, it starts to lose MW, and it loses them pretty dramatically, as you can see. On a 100 degree day, you're going to be at more like 82 to 83 percent of your nameplate, and of course, if the weather is colder than 59 degrees, you can actually get more than nameplate. And this curve is kind of baked into the contracts because it's always been this way, and the unfortunate part about this is, generally where you have your shortfalls in most locales, is in the hot time of the day because everybody is turning on their air-conditioning units, plus generally the wind isn't blowing quite as much when it's really hot out, 95 or 100 degrees, and at that exact moment is when your gas turbine fleet generates the least of the entire year. So essentially, what this technology will do, turbine inlet cooling, which actually started in California in the '80s, we actually did the first projects in the Bakersfield Area in the mid '80s. At that point, basically what you did is you took weather out of the equation, so you -- it's what we call turbine inlet cooling -- you would lock in the design point, let's say 50 degrees, and so now you're getting about 103 percent of the nameplate all year long. That's turbine inlet cooling.

But generation storage is an improvement on that because now you have much more flexibility. Now you have the ability to almost instantaneously change that operating point by changing the temperature of the air going to the gas turbine through stored energy, which I'll talk about in just a minute. But I want you to picture this curve and remember that all we're going to do now is we're going to control the weather. What we used to do, we fixed the weather at 50 degrees, no matter what the weather was, now we're going to change the weather to 75 degrees, 74 degrees, 52 degrees, whatever it needs to be, and we'll do it very very quickly. Next slide, please.

So this is kind of what it looks like. Basically, you're going to take off-peak power, so this is also a way to store energy, so we're going to take off-peak power, this could be wind power, you're looking for a load sync, this is a perfect load sync. We'll utilize that power, it can be either at a fixed rate or a variable rate, so this can essentially act as Demand Response because essentially what we're doing is we're talking power, pretty much wherever we need it, wherever it's cheapest in a 24 hour cycle, we're going to consume that power, and we're now going to store it in the form of thermal energy storage, in the form of chilled water. Okay? So let's just assume we're doing this at night, we're talking low cost renewable power and turning it into cold water, and we're storing the cold water at night. In the daytime, we now have all this stored energy and, as the weather starts to change, and as the Grid needs start to change, we can dispatch this stored energy very very quickly to change the air temperature really fast.

Now, this is a great opportunity to, if you want, ramp up/rig down, because all you really need to do is you're essentially controlling a pump. You're changing the speed of the pump, which will change the air temperature within minutes to the turbine, which will change the output of the turbine.

The other nice thing about this is it's very efficient. If you take about a MW hour of off-peak power, let's say renewable power, you can make about eight MW hours, you're in the peak, with that stored energy. And I think there is a part in here where we talk about the round trip of the thermal energy itself is actually slightly above 100 percent, and the reason for that is, we're making the cold at night, the ambient temperatures are lower, and so the refrigeration system is running more efficiently than if we had to run it during the day, which is the way we used to do it in the old turbine unit cooling arena.

So what are the barriers to the market? Well, I think Mark has hit on a lot of them. Actually, part of the problem is that this degradation curve that we just talked about is already baked into the contract; it's baked into the contract. So let's say if Calpine wanted to make an investment to gain this additional 15 percent of flexibility, how do they get paid for it? It's an existing plant, we've now picked up an additional 15 percent MWs, you're in the hotter times of the day, but there's not a good way for them to get paid for it, unless, as I understand it, they have to reopen the entire contract, the main contract. So one suggestion is to look at an overlay contract, in other word, they've already got a contract for the base plant, now they're going to look at making an investment, it can be not just this, it could be anything, an investment in maybe the HRSG side, whatever, but there needs to be a way where they could get a contract for that incremental performance, which this would offer.

Secondly, because this essentially turns your combined cycle into what we call a virtual peaker, but yet it's still using existing iron in the ground, there needs to be a way, when you're looking at additional peaking MWs or flexible MWs, that this can bid into that. Generally, the RFOs that look at new capacity, or new steel in the ground, kind of ignore the fact that, well, we can add some steel, it's a different kind of steel, it's a tank in a refrigeration system applied to an existing power plant, but the additional MWs are going to show up at the same place where the original MWs were, right? So if there could be a way for the RFOs to bid in generation storage, and then, finally, we would recommend that, before a peaker was built, look at the economics of adding generation storage. As Mark alluded to, and which I fully agree with, the cheapest MWs and the cheapest flexibility is very likely to be enhancing what you already have. It's also the quickest in many cases. So I think this would do that. Next slide.

So just to review what we've talked about, there's an opportunity here in California to gain an additional 1,500 flexible MWs from your existing combined cycle fleet with a cost of about -- well, if we're retrofitting, I think we're probably around $350 to $450 per KW, and it can be done with no new transmission. We could actually do it in time for next summer, 2013, it can move that quick, ready with 100 percent efficiency on the energy storage, it's very flexible, it's the only way I know where you can actually take MWs off the grid in the form of energy storage, and then deploy them at will to generate eight times the MWs that you took during the off-peak. It's proven, it's very reliable, as a matter of fact, and the maintenance cost of these generally is about one-tenth per MWH vs. what the gas turbine itself is. And it's extremely environmentally friendly, you know, this will reduce the amount of start/stops of your combined cycles by increasing its operating range, and it gives a load sync for those shoulder periods where you're at low load already, and you're looking for a way to soak up those megawatts. Thank you.

COMMISSIONER PETERMAN: Thank you, Mr. Pierson. That was very useful, I think it was well timed at the end of the presentations because you gave a real world example of the type of retrofit that can be done to what the existing and new plants. I would welcome, perhaps from Calpine or some others, in formal comments, or comments submitted by other parties, in addition to the generation storage example provided by Mr. Pierson, are there other -- what would be other adjustments one could do that would be in kind of that same spirit, that would improve the efficiency by a certain amount. Also, Mr. Pierson, I was thinking that your technology would work well also with the co-location, with the wind facility, for example, in terms of being able to use some of that off-peak power for storage. I didn't have any more specific questions about your presentation. Chair?

CHAIRMAN WEISENMILLER: Yeah. Just a couple. One is, again, my understanding is that this only works in combined cycles, right?

MR. PIERSON: No, actually, turbine inlet cooling has been applied actually much more to peakers.

CHAIRMAN WEISENMILLER: Okay.

MR. PIERSON: Generation storage, basically the idea of using the off-peak, could be applied to peakers, as well. It absolutely could.

CHAIRMAN WEISENMILLER: Okay. The other question is you said 400 applications around the world. What's the maximum amount of time that any of these have been in operation? Or how long?

MR. PIERSON: Well, the longest ones have been here in California.

CHAIRMAN WEISENMILLER: Okay, so Bakersfield, so that would be --

MR. PIERSON: Yeah, probably 1987.

CHAIRMAN WEISENMILLER: Okay, so basically no problems on the financing side in terms of the types of guarantees that could be provided. Is that true?

MR. PIERSON: That is true. The vast majority of those have been -- you know, they were put in when the plant itself was because the retrofit still has this -- it's a contract problem, it's a market problem, it's not a technology problem, so whether we add this technology to the new or an existing gas turbine doesn't really affect the reliability or anything else, but it does affect the way things are contracted.

CHAIRMAN WEISENMILLER: Okay, now in terms of markets, is there any way in terms of the CAISO's products that this type of application would have a market? Just in the ISO context?

MR. ROTHLEDER: In the short term, I think this would be useful in terms of meeting the flexible capacity needs, the flexible product that we've introduced, five-minute ramping.

CHAIRMAN WEISENMILLER: Okay. And I guess I'll hold off until Todd Strauss is on later today about storage, but ask Todd the contracting questions at that stage.

COMMISSIONER SIMON: Mr. Kistle, I had one question in reference to your Huntington Beach storage technology in light of the SONGS dilemma that I had referenced, I think, in my opening remarks. Will this -- will you be utilizing this to test this storage backup, the SONGS scenario --

MR. KISTLE: No. We've removed the one MW battery that we had there for testing and the system is no longer connected, it has been relocated.

COMMISSIONER SIMON: Okay, thank you.

COMMISSIONER PETERMAN: Thank you. I think now I'd like to turn to see if there's any public comment in the room or on the phone, and then return to our panelists for any final comments or observations in light of what they heard from their colleagues on the panel, with a wrap-up at 12:30. Thanks.

MS. KOROSEC: All right, anyone in the room like to make a comment? Todd, go ahead.

MR. O'CONNOR: Thank you. My name is Todd O'Connor. I represent Critical Path Transmission and it's part of the High Desert Power Authority, a joint municipal powers authority representing the cities of Pittsburgh and Lancaster. Thank you, Chair Weisenmiller, Commissioner Peterman, and Commissioner Simon, for this opportunity to speak. My comments are few.

In referencing Ms. Bird's presentation, and on page 8 under Dynamic Transfers, one of her key recommendations is -- I can quote -- "identify most receptive and most restrictive transmission lines." And my question is, has there been any discussion in terms of what factors go into defining the most receptive transmission lines and, conversely, what factors go into finding the most restrictive transmission lines? And on page 11, a key recommendation focuses on siting wind and solar together to minimize variability of aggregate output. And Kern County is currently, to put this in perspective of what's happening throughout Southern California, in Kern County for example, in 2011, Kern County has issued permits for 1,334 MW of wind, and 1,570 MW of solar, and they're capable of being integrated into two balancing authorities, at least, one through the municipally owned utility lines, LADWP, and SCPPA, and the other obviously is CAISO. And through 2011, Kern County has issued 7,000 MW of wind and solar, 3,900 of which are on-line. And I thank you for this time.

COMMISSIONER PETERMAN: I don't know if Lori is still on the line, so I might turn to Mark and see if he can comment on looking at the capacity for dynamic transfer. I believe that was your question, particularly looking at IED's balancing authority, basically, and ISO, was that it?

MR. ROTHLEDER: Specific to dynamic transfer or defining the least restrictive and most capable transmission to transfer the energy, I wasn't sure if it was just specific to dynamic transfer.

MR. O'CONNOR: It was referring to that, to that recommendation of what factors went into defining most restrictive and, conversely, what factors or criteria are you looking at in going the opposite way.

MR. ROTHLEDER: For dynamic transfers, I mean, the ISO did perform some studies around dynamic transfer capability, looking at the dynamic capability of transferring and the variability impacts of transferring variable resources across intertie paths, and so that was helpful in at least giving us confidence that, at least on our major paths, it wouldn't look like, at least from an ISO perspective, there would be any significant limitations at the expected level of renewable integrations that may use those paths. We're looking at coal and we were looking at Western River. That said, we're also participating in other balancing authority studies that are looking at the similar things in their balancing authority areas, so while we might not have identified a limitation, others may identify limitations about voltage control devices that could limit the import capability of dynamic transfers. In terms of just general transfer capability, I think we -- the ISO has a transfer planning process that looks at queues and the interconnection requests, as well as transmission plan upgrades needed for various policy, economic, and reliability needs. And so, as part of that process, we do identify bottlenecks and maybe not identify where the least bottlenecks are, but at least where bottlenecks may arise in the case of proposed projects, and how to relieve those bottlenecks.

CHAIRMAN WEISENMILLER: Okay. I think what may help, and just following up on Todd's question, is if you could submit the prior studies you referred to initially that the ISO has done?

MR. ROTHLEDER: Sure.

CHAIRMAN WEISENMILLER: For our record, that would be good. Thanks.

COMMISSIONER PETERMAN: And I would also say, regarding your question, feel free to -- Lori is not on the line anymore, just send her an email directly, it's in her presentation, about the criteria used in that study.

MR. O'CONNOR: I'll do that.

COMMISSIONER PETERMAN: Thank you very much.

MR. O'CONNOR: Thank you.

COMMISSIONER PETERMAN: Sir?

MR. O'KANE: Thank you. My name is Stephen O'Kane and I'm with AES and, with full disclosure, I'm a colleague of Mr. Kistle's here. There's an issue that we danced around a little bit here on this panel and we talked about renewable integration of the various options, and we tend to think about it as its equal wherever we put it, but location matters. Location is hugely important and I think we've even been thinking about it the wrong way, co-locating some of this flexible integration with the renewables. I think we touched on it very briefly at the beginning, is that the thing to do is not -- it's not with the renewables, because serving the load, the local reliable areas and then providing the flexible ramps and start times, capabilities right there.

Mr. Kistle addressed what the developer really needs to do is to do is come up with a project that fits the needs for a specific location, specific project. So it's not a one-size-fits-all, there's many different options out there and it really depends on location, and I think location has to be addressed first before we start looking at many different options out there, and watch out for this trap of providing the flexible capabilities, gas-fired capabilities, at the points of the intermittent generation technologies, so that local reliability area is the most -- must be served first. And I wonder if CAISO could expand a little bit on that.

COMMISSIONER PETERMAN: Well, I have to say, first, thank you for your comments. And I think, definitely, location does matter, I think when you start first, though, with the attributes we're looking at and see to what extent location matters for some of them, for inertia, definitely it does matter, for some of these other ones, less so. And I think one of the takeaways I have from this discussion is we know what they actually should be going after; within those, what is the prioritization? Where is the sweet spot where you get a project that meets all of those? Is there a project that optimizes all of those? Mark?

MR. ROTHLEDER: I think he raises a very good question. This is a multi-faceted problem. You have capacity needs, you have local constraints, transmission constraints, you have attributes of operational characteristics, and frankly, it's a complicated enough problem that it begs a question of, okay, do you solve this with some kind of global optimization that tries to minimize the cost of everything? Or do you try to address some of the issues sequentially, and then deal with the residual needs at some point? And I think in the long run, I think we need to look for a market structure that, as Mark Smith indicated, provides some kind of sustainable, flexible and competitive way of meeting these needs and dealing with these things. We don't want to be here talking every year, every five years, about the issue, but you want some kind of structure in place that basically sustains and evaluates this on a normal basis, looking out five to eight years, and you basically then competitively get what you need to meet those local system and attribute needs, and you do it in a competitive way that recognizes that there may be switch-out of technologies at some point, as a technology becomes less efficient and can be replaced, a structure that can allow for that would be very healthy. I think we need to start looking for those opportunities.

COMMISSIONER PETERMAN: Thank you. I also think historically, integration has been the responsibility of the System Operator, both providing it and the cost associated with it, and we've talked about in past workshops how consideration of those costs, the PUC is now looking at considering those costs in the procurement plans for renewables, and so one of the interests I have in co-location is thinking about to what extent can we have generators take more responsibility for some of the integration requirements, and to what extent can that be provided as a package, the power, vs. having to deal with the integration afterthought.

MR. ROTHLEDER: Yeah, and that opens up another set of issues and questions about how to best efficiently send those signals to the resources that may be able to self-manage that. Do you do that through allocation of the cost of the short-term products? Or longer term capacity? So there's an allocation question that comes into play there. Or do you attribute integration costs as the utilities, those that are trying to meet their responsibilities, you say, okay, there's a certain cost average to that, and you build that into the decision making process. I think our perspective is that it may be most efficiently to send the signals to the resources that are maybe resulting in the need for this additional flexibility and those costs would be then eventually passed through to the load serving entities, but they would be done in potentially a more efficient way, and decisions could be made at the level, as you described, of putting a set of mitigating measures in place at the same location, or a different location, to resolve those issues. Again, I think it's a structural issue as to how you do that in the most efficient way. And certainly, cost allocation is something that needs to help guide that.

CHAIRMAN WEISENMILLER: Yeah. I think the other question, and we never quite got to question 4, and certainly in people's written comments, and obviously the 4,000 MW of flexible resource we're looking for, if we were located all at Folsom, you know, would not be useful in terms of dealing with other local capacity needs or, you know, spreading that through the transmission in terms of dealing with congestion. But to the extent the gas plants provide a variety of services, not just the flexibility, but that certainly affects the co-location questions. I think, on the integration issue, you know, a question is going to be just economies of scale, and if you really drive it all the way down to every resource, is that uneconomic compared to having the integration resources coming from substantially larger assets, which you will find out over time. But, anyway, as people do their written comments, we certainly would appreciate more comments on the questions we never quite got to, and I think the intent at this point is to try to give everyone one last opportunity to wrap up, you know, in terms of what you've heard so far.

MS. KOROSEC: Excuse me, Chair, we do have some questions on the WebEx.

CHAIRMAN WEISENMILLER: That's great. Let's get them.

MS. KOROSEC: Okay, we have Ben Mehta. Ben, your line is open.

MR. MEHTA: Okay, I'm Ben Mehta, an ex-EPRI, PG&E and CEC Manager. I recently came from a World Hydrogen Energy Conference in Canada, in Toronto, and the discussion at the meeting among the world community, particularly the Germans, the Canadians, and Japanese, was to consider converting the intermittent renewable power using electrolyzers into hydrogen, and storing and transporting that hydrogen in the existing natural gas storage and transportation system. And there was quite an overwhelming positive interest in the conference, and I wanted to hear whether any of your panelists had any comments.

COMMISSIONER PETERMAN: Thank you for your comment, that insight from your conference. I'm sitting here thinking that just sounds a very expensive way to deal with intermittency, although it is a way, and do any of our panelists have any other comments on that? They don't have any other comments on that today, but thank you for bringing that up as an option, as well. It's just something always we can consider going forward and I think, generally, as we think about hydrogen, we've had to think about it in our transportation work here, as well as our renewables, it's just the technology is still expensive right now, and so that would be the question, but to the extent --

MR. MEHTA: No, it is not expensive, it is commercially available now, and two big companies in Canada and in Germany are going to demonstrate at some scale over the next three years.

COMMISSIONER PETERMAN: Well, very interesting. If this is a topic you're particularly interested in, don't hesitate to submit information to the Docket, because I would love to be proven wrong about it being more costly. Thank you.

MR. MEHTA: Okay, thank you. Bye.

MS. KOROSEC: All right, and I do want to open the phone lines just to give the opportunity of those who are phone-in only. Anyone on the phone who would like to make a comment, now is your chance. Your lines are open. All right, I think that's it for the public comment, then.

COMMISSIONER PETERMAN: Great, well we will have a public comment period at the end of the day, as well. David, I'll turn this back over to you for any, again, comments from our panelists, some burning issues or comments you want to share with us and, again, we appreciate you submitting anything else you would like in written, as well.

MR. ROTHLEDER: No, thank you. I think I said enough.

COMMISSIONER PETERMAN: We should have given you a set up here, you had to talk so much.

DR. MARINI: Thank you very much for having me here. It was an interesting discussion.

MR. KISTLE: Thank you. No further comments.

MR. PIERSON: I guess the only comment I would say is, you know, the technologies are out there. The challenge is getting the markets to be able to adopt the technologies. If we could fix that problem, I guarantee you, entrepreneurs will come up with all kinds of solutions, but they can't change the market. That's really the biggest problem of all.

MR. SMITH: Thank you, it's Mark Smith, and thank you for inviting Calpine and me, particularly, to speak, I've enjoyed the panel. It's been very very interesting. Calpine's message here is pretty plain and simple, let's try to find the lowest cost way in order to integrate renewables as the challenges occur over time, and we think that one of the lowest cost ways is by modifying existing assets. Thank you.

COMMISSIONER PETERMAN: Thank you. Well, thank you very much, Mr. Vidaver, for your moderation and we also welcome your recommendations, as well. With that, we are going to break for lunch. We'll be back at 1:30. Thanks.

(Recess at 12:27 p.m.)

(Reconvene at 1:35 p.m.)

MS. KOROSEC: We're going to go ahead and get started with our Panel 3, which is Assessing Demand Response Potential to Provide Renewable Integration Services.

MR. GRAVELY: Good afternoon. Mike Gravely from the Energy Commission R&D Division, and we'll be talking for about the next hour and a half on Automated Demand Response, and the primary focus is going to be on using Demand Response for ancillary services or for supporting renewable integration. Classically, we use it for peak load reduction, and usually for both, but today's focus is going to be on renewables.

Just a quick introduction from our work here at the Commission. We've been working in almost the last decade on Demand Response, and probably the last five years more pretty aggressively on automation Demand Response for all sectors, residential, commercial buildings, and industrial. We learned early on that the automation of Demand Response makes it much more predictable and it makes it more reliable. We found in most cases we got more Demand Response than we were able to much more reliably predict what we were going to get. So we started working on an open protocol, we didn't want the market to go out and have dozens of different types of protocols and signaling architecture, so we started working with industry and with the Federal Government to come out with an open automated Demand Response protocol and it's been named OpenADR, and you'll see as we go through, we'll talk a little bit about it later today as we look at the different ways of automating it. It basically provides a protocol opportunity for individuals to have their proprietary tools, at the same time the communication is not proprietary, so everyone has the opportunity to participate. And it has been, as a result of ARRA, there's about a half a dozen key projects being demonstrated in the country and, as you can see, throughout the world, there's been interest in the automation of Demand Response, particularly using this protocol, the National Institute of Standards and Technology is working right now to come up with a standard protocol for OpenADR for the country to use as we go forward.

So the panel today, we do have a lot to cover, so I will go ahead and start in with the first speaker. I think Scott is online with us. PJM has been very active in the area of participating with Demand Response in this market and, so, are you online, Scott?

MR. BAKER: I am. Can you hear me all right?

MR. GRAVELY: We can hear you fine. So go ahead and we'll bring your presentation up and feel free to start talking a little bit about what's happening on the East Coast.

COMMISSIONER PETERMAN: And I'll just interject here. Hi, this is Commissioner Peterman. If you weren't able to join us for the morning sessions, I'll just offer a comment about what we heard, particularly from the ISO, that there's going to be a need for resources that can provide those regulation services within a few seconds, or a few minutes, and really looking at that smaller subhourly timeframe. And so I appreciate there's much to talk about with Demand Response, and we've talked about some of the opportunities of Demand Response in previous IEPR workshops, and we really again want to focus on the opportunity for Demand Response as an integration resource, and as a complement or a substitute for both storage and natural gas. Thanks.

MR. BAKER: Thanks for that lead-in, Commissioner, I appreciate that comment because my presentation here is really going to focus on PJM's changes to its regulation market and what we've been doing in attesting and accommodating Demand Response in the regulation market. I apologize, bear with me a little on my voice, I'm a little bit under the weather here.

A quick introduction to PJM and who we are on the East Coast, we are an RTO covering 13 states plus the District of Columbia. We have about 750 member companies serving a little over 60 million people, and we have a forecasted peak load in MWs of 163,800. About 21 percent of U.S. GDP is produced within PJM, so we are a very large service territory and I think that should be noted in contrast to some of the discussions around system control, renewables integration, that were happening this morning related to California, so there are some differences there.

To give you a picture of renewable energy in our service territory, these are the states that have RPS targets, states that have an RPS goal. If you add --

take these mandates, forecasts then into the future, given their timeframes and their schedules, this translates into about a 42,000 MW wind requirement and about an 11,000 MW solar energy requirement, that translates into about 14 percent of the energy in PJM coming from renewables by about 2026. So while today we only have about 5,000 MW of wind, and just recently passed 1,000 MW of solar energy, we do see the RPS mandates ramping up in the future here and recognize the need for advanced technologies markets to accommodate renewables. Next slide, please.

This is typical where summer peaking RTO, typical load curve, this actually happened to be our all time peak last year, load curve, and if you -- again, please -- you'll see what our wind production did on that day. These slides of wind generation, and it's really no different in PJM, our geographic territory lends itself to this type of wind profile during our peak period. So highlighting the need for storage and advanced Demand Response technologies here. Next slide, please.

Again, I wanted to really focus my comments today on the regulation market. Given PJM's size and the resources that are in our territory to date, we're 180,000 MW of generation capacity, we will deal with integration near-term, potentially mid-term, through our ancillary services market. And regulation will be a very important part of that in the near term. I wanted to focus today my comments on PJM's regulation market and how it's changing some of the new technologies and demonstrations that we've done to help accommodate them. I mentioned 14 percent of our energy is forecasted to come from non-dispatchable variable resources.

The other reason that we are making changes to our regulation market is to increase the efficiency of that market as we will move to a performance-based regulation market, which means that resources will be compensated based on their contribution to system control, that's a big change. In the past, resources were all compensated with the same clearing price, regardless of how much one resource contributed to the system control over another. So that will change. And this is really also going to help transition cost-effective energy storage in the electric system.

So here I listed, I think, five of the biggest changes that we have made and are making, I should say, to the regulation market. The first there is just, four years ago now, we had a 1 MW battery facility, actually on PJM's campus, and we used that demonstration to help develop an entirely new regulation signal that is tailored for fast responding resources. And also, those resources which may be limited in energy. So this is called the Dynamic Regulation signal and it is calculated to be an energy neutral signal that's also highly correlated to system frequency, energy neutral over a rolling average, and what this signal does is it allows PJM to better use fast responding resources without straining those resources such that they aren't able to compete in the market for the amount of time that would be necessary to have a sustainable solution there. So, one of the things that we found prior to developing this signal was that our regulation signal was biased down, which meant that energy limited resources would tend to fill up and have to take themselves out of the marketplace, and so we really saw a need, in order to encourage these new resources to come to PJM's marketplace, the need to develop a signal like this.

I mentioned Performance-based Regulation, briefly, this is the FERC Order 755, which is requiring RTOs and ISOs to develop a two-payment system for regulation, one for capacity and one based on performance. The thing we have made, which has really developed a lot of activity in the Demand Response marketplace is the fact that we lowered our regulation capacity requirement, just previously one MW, down to 100 KW, and this is actually a minimum capacity requirement now across all of PJM's markets, energy, capacity, and ancillary services.

This was, I think, an important change to help new, particularly Demand Response resources, enter the marketplace sooner, rather than later. It gives us a much better understanding of how these resources participate, what their operational characteristics are. So that approval from FERC was issued last fall. So, since then, we've had a number of smaller Demand Response entities entering PJM's regulation market.

The last two is a recent FERC approval for Sub-Metering of Demand Response Regulation, and the last bullet there is a new Registration category for Demand Response participations called a Regulation Only. What that new category does is it allows for more flexible market participation within the same Demand Response site, in other words, multiple CSPs, Curtailment Service Providers, and control Demand Response resources at the same site, and participate in different marketplaces, not during the same hour. Next slide, please.

So I just want to highlight a couple of these alternative resources that are now in our marketplace, or that PJM has done demonstrations with to sort of better understand their characteristics. The first is an AES project called Laurel Mountain, which is a wind farm, 98

MW wind farm in West Virginia that is co-located with a 32 MW battery. And this is the largest battery storage system in PJM to date, and it is currently providing fast response regulation services in our regulation market. My understanding is that AES is also using the battery to test different wind firming, if you will, capability. Next slide.

I want to steal Ron's thunder because I see now that he's on the same panels, but just briefly, we've worked with Enbala which is a company that takes advantage of what they call process storage and if you go to the next slide, please, what Enbala has done in PJM's marketplace is applied technology -- control technology -- to existing loads, in this case, water pumps at a wastewater treatment facility. And when they operate individually, you know, it looks like chaos, essentially, but when aggregated in an unique way, if you go to the next slide, please, what they're able to do with these water pumps is follow PJM's regulation signal really quite nicely, and Enbala is currently a PJM market participant in providing regulation services with Demand Response products. Next slide, please.

This is one that we talk about quite often because we think there's really a lot of potential for this energy storage resource here, I'm talking about electric storage water heaters. We have been running a demonstration with the Steffes Corporation for some time now, learning and collecting data on how large volume electric water heaters are able to follow frequency regulation signal, the fast response regulation signal, and also optimize their usage of electricity for LMP. And so this water heater, which is in PJM's headquartered lobby, actually provides hot water to our building and it also looks at the day ahead LMP schedule and chooses which hours it's going to heat water. And in those hours that it's heating water, it's also providing regulation to the system, so essentially overnight it's providing frequency regulation and also heating water to provide obviously a service to our building. Next slide, please.

Another very interesting type of distributed energy storage and Demand Response product is obviously electric vehicles. There's, of course, lots of talk about what electric vehicles are going to mean to the electric system, when deployed en masse, and we are no different, very interested in how these resources are going to interact with the electric system. And we have run a project a couple years ago with the University of Delaware and an industry consortium called MAGIC, and what we demonstrated was the aggregation of electric vehicles to provide frequency regulation and this is really -- this is technically feasible activity, but it turns out it's very difficult to do from a business rules perspective, and so PJM, over two years with this project, got a lot of insight into what business rules, or barriers were presenting themselves for a distributed energy storage technologies, in particular, to integrate into PJM's Demand Response markets. And this project has been very valuable in educating PJM staff and also our stakeholders into the various issues that come with distributed energy storage technologies.

So I wanted to keep my comments brief and focus on the regulation market here, and I apologize for the voice here, but I'm happy to take any questions, otherwise, I look forward to the rest of the discussion on this panel. Thank you.

CHAIRMAN WEISENMILLER: Thank you. This is Chairman Weisenmiller. I guess I wanted to ask you how many MW of Demand Response capability does PJM have on its system at this point.

MR. BAKER: Total Demand Response clearing in our forward capacity market, I believe, we just cleared our reliability pricing model in May and I believe the total number of cleared MW was 14,800, approximately, MW. That is the capacity Demand Response product.

CHAIRMWAN WEISENMILLER: Okay. And what sort of time responsiveness do you have in those MWs?

MR. BAKER: Those particular MWs that operate in the capacity --

CHAIRMAN WEISENMILLER: Yeah, exactly. I mean, if you need to get a response, how fast can you do that?

MR. BAKER: It's going to vary on the type of resource, I believe, that's bid into the marketplace. The response duration varies between different products in the capacity market. I may have to defer to one of my panelists for the response, the speed at which PJM requires the Demand Response capacity resources to respond. I'm not exactly sure and I don't want to give you a wrong answer.

CHAIRMAN WEISENMILLER: Okay, well, if you could respond following up -- I'm really focused on Demand Response as a way to deal with renewable integration, and so trying within that hour type of response, as opposed to a lot of our traditional programs tend to look at Demand Response more with a day ahead market, so I was just trying to understand how much of the PJM market was day ahead vs. day of market, or within that hour market.

MR. BAKER: The capacity -- that number of MWs that I just described there is in the capacity market and most of that is participating in the emergency response program, so these are resources that are called upon up to a handful of times throughout the summer to respond to emergency conditions on the system. So this isn't typically a product that we see for use for renewable integration. It's possible that you could use it in the case of an extreme ramping event, but the amount of wind generation that would be needed on our system to create that situation would be much much more than we're predicting currently.

CHAIRMAN WEISENMILLER: And roughly what did it take to get that much -- that many MWs, either in terms of the size of the capacity payments, or the program structure?

MR. BAKER: Well, I mean, the first answer is probably it took a forward capacity market construct to get that Demand Response, you know, in the marketplace. In terms of the clearing price, are you talking about this year's clearing price or just in general trend?

CHAIRMAN WEISENMILLER: In general terms would be good.

MR. BAKER: Yeah, the clearing price for forward capacity has been, you know, it fluctuates each year, it's typically somewhere around $100, but it has had wide swings in some years, it also depends -- it is location specific, as well. So we have particular areas, we call them load deliverability areas, but the areas sometimes clear at higher prices because they're constrained, so it's tough to give you just kind of one answer there. This year's price was over $150 in most of the RTO, was slightly higher than that in some regions, and it was above $300 in one particular region in Ohio.

CHAIRMAN WEISENMILLER: Okay, thanks.

MR. KEEHN: Can I ask one question? Can you just tell me what the units are for that? You said dollars.

MR. BAKER: Yes, I'm sorry, that is MW per day. Dollars per MW day. And the most recent market results are available on PJM's website, if you go to markets and then go to reliability pricing model, you'll find results from the most recent auction there.

MR. GRAVELY: Thank you very much, Scott. Actually, Ron is not here, he might have been able to respond to your timing if he gets here, he's coming in today on a plane, so he may --

MR. DIZY: I am here, actually. I'm on the phone.

MR. GRAVELY: Oh, okay. So I thought maybe you might respond to that question he had on response time for the services you provide.

MR. DIZY: Oh, sure. So I, yeah, well, in our case, the regulation signal is a four-second signal. In general, generators are responding anywhere from a minute to several minutes. Our typical response is 30 to 60 seconds for full effect, although you start responding right away. So when you look at those charts and you sort of see the pace of response, one of the things you find is that loads certainly are capable, at least in aggregate, of responding at least as fast as what we're used to with generators and in some cases quite a bit faster.

MR. GRAVELY: Okay, thank you.

MR. DIZY: Did I answer your question?

CHAIRMAN WEISENMILLER: Sure, that helps.

MR. GRAVELY: So we'll go to our next panel member here, Andy Satchwell from Lawrence Berkeley National Lab. They've been doing work for both California and other states and the Federal Government in this area, so Andy will update us on what they've learned, and some of the barriers to DR.

MR. SATCHWELL: Great. Thank you, Commissioners, thank you, Mike, for this opportunity to speak with you. As Mike said, my name is Andy Satchwell, I'm at Lawrence Berkeley Labs in the Electricity Markets and Policy Group. My particular research areas include Demand Response and Smart Grid, Economic and Policy

Issues. Particular to our discussion today, I've been leading the technical assistance work for the Western Governors Association, Estimation of Demand Response Resources for WECC's Transmission and Generation Expansion Planning, as well as working with WECC staff on the modeling of those resources. And then we're also currently engaged with a DOE project that is looking at Demand Response as ancillary services across the nation, and our portion of this specifically is to look at the identification of barriers related to procuring Demand Response's ancillary services, so just simply put, what's the business case for these types of resources? You know, just because Demand Response is a cost-effective resource, it doesn't necessarily mean or imply that utilities, or Aggregators, or customers, will pursue those resources.

So what I wanted to focus on today was just giving you all a framework to think about and evaluate the barriers that are going to be discussed in this panel and as you guys consider Demand Response resources.

So I think it's actually helpful to set this framework up in a hierarchical way. And focusing on how to generate and capture value to market participation for Demand Response, and this framework is essentially a hierarchical set of questions, so the first question to ask is, who is eligible to provide the Demand Response's ancillary services? So that goes to produce requirements and product definitions. And the second question really asks, who can bring these Demand Response resources? So are we talking about here the Aggregators, LSEs or utilities, or the customers, themselves? And the third question in this hierarchical framework to ask is, are customers interested? Where is the value proposition? And also the consideration of other Demand Response programs they may be enrolled in or considering to participate in. And I think this framework is useful for policy makers and regulators to consider both the upstream and the downstream issues. While a regulator or policy maker may not have the ability to effect the Reliability Council Rules, more of an upstream issue, by looking at this framework, you can consider being prepared on some of the downstream issues when those other issues get addressed because, as you're well aware, this stuff doesn't always happen perfectly, and isn't always perfectly timed, so that anticipation is what's sort of present in this framework. Next slide.

So the first question, who is eligible, this really gets to the reliability and market rules that may define the ancillary service product definitions, or their requirements.

And another way to look at this is to ask what is eligible. For an example, it's barrier specific. In the WECC region, in our work, the WECC Reliability Rules, as currently designed, do not allow Demand Response to function as spinning reserves or regulation reserves, only non-spinning. That said, the WECC stakeholder group just passed a few weeks ago a standard that allows Demand Response and other loads to provide spinning reserves, and there's sort of an inherent part in the language that refers to being frequency responsive.

So these are the types of barriers, as well as the ways that they're being addressed, that have to occur for there to be opportunities for Demand Response to provide these ancillary services. Next slide.

So the next question is, who can bring the resources? And I think this question helps to identify and categorize barriers that result from retail ratemaking issues, as well as barriers to market entry. So here, I've identified a couple of those, you know, for example, ancillary services costs may be simply passed through to customers and the motivation for the utility to reduce their ancillary services costs may be non-existent. And the utility also has to evaluate and understand that trade-off between generating shareholder value from capital expansion and the offering of Demand

Response programs that went into that capital expansion. Next slide.

And the third question looks specifically at whether customers are interested in participating in these Demand Response programs. And this question is meant to identify barriers from a customer value proposition standpoint. Customers may be limited by rules that prevent them from signing up for multiple Demand Response programs, or they govern how those customers respond when they're signed up for multiple DR programs.

And I think it's important to note that Demand Response as an ancillary service will provide an additional revenue stream for customers and Aggregators, so the success of these programs depends on the maturity and participation in other Demand Response programs.

The thought I want to leave you with, before we get into the full discussion here, is that overcoming these barriers requires policymakers and regulators to consider encouraging the development of fast DR in the short and the long-term. And in the short-term, ongoing research and demonstration projects, like what's being done at LBNL, you know, in particular the areas of Auto DR that Mike was talking about, shows among other things that customers have more capability than the utility defined Demand Response Program needs and rules, and that this additional capability can be tapped for short periods and short durations of time. So, customer-owned technologies to control these multiple loads becomes a significant enabler in their ability to participate.

And I think the regulators and policy makers have to look at removing those boundaries and barriers to the existing and planned Demand Response programs to really tap into that additional capability. And obviously, with that comes the problem of compensation. Compensation is a significant problem when you're looking at fast DR. And there needs to be a consistent value function to encourage and incent customer participation. So that finishes up what I wanted to lead into, but I look forward to the discussion.

CHAIRMAN WEISENMILLER: Thanks. I guess my follow-up question is, have you identified the specific barriers in WECC's rules that could or would prevent us from relying upon Demand Response in the dispatch of our resources?

MR. SATCHWELL: The rule specific to that is the fact that, on the books, as currently exists, is that requirement that Demand Response can only count for non-spinning. But there's this change to the rule which I think ultimately has to be approved by FERC, I'm not sure on the full timeline of that. In our work, assessing the size of the Demand Response resources in WECC, the Balancing Authorities in WECC submitted non-firm load forecasts going out 10 years, but they only recognize those resources that are defined by the NERC Reliability Rules, so those are traditional load control programs, some demand bidding, and critical peak pricing, but only those programs where there is utility control. So there's kind of this older framework for defining these Demand Response programs that doesn't really recognize them in WECC.

CHAIRMAN WEISENMILLER: Yeah, I know. We've been trying to deal with the summer of issues and obviously would like Demand Response to play a key role in the Demand Response, so certainly we're running into some of those WECC issues at this stage, which certainly we intend, we, the Governor's Office, and the ISO, to get it just as fast as we can, and the PUC.

COMMISSIONER PETERMAN: Yes, thank you for that presentation. Just as clarification of "summer of," the summer of 2012 and the concerns around San Diego and the San Onofre outage, not everyone is always familiar with our short-term concerns here, but the Chair and our sister agencies have been working diligently on making sure that the power stays on in that southern part of the state.

I'll just say I'm looking forward to Mr. Keehn's presentation and specifically maybe he can touch upon, as well, that you highlighted a barrier being the market rules in terms of allowing DR to be aggregated, and just would be curious to learn specifically more about that and whether there are some recommendations that can come out of this body related to changing those market rules, or if you have any comment on that, Andy, if you have more specifics on what you're thinking about.

MR. SATCHWELL: No, I didn't have any comments at this time. I felt that the folks on the panel here that are really engaged at the California level and involved in their own system operations might have specifics, but we can certainly come back to thinking about ways to address and overcome those barriers.

COMMISSIONER PETERMAN: Thank you. Commissioner Simon.

COMMISSIONER SIMON: Thank you, Commissioner Peterman. Mr. Satchwell, referencing San Onofre and the summer of 2012, and it sounds like that great movie, Endless Summer, if anybody ever caught -- I hope it's not endless, at least. But one of the things that my fellow Commissioner, Catherine Sandoval and I have been concerned about is the issue of ethnicity and marketing and outreach, understanding that this will affect Southern Orange County, as well as Northern and much of San Diego, and that the populations have changed dramatically, both by way of retail, and even some commercial, and small scale industrial businesses. Is that -- in terms of that outreach, are we looking at, in your view, if you view this area, are we doing enough in the language area to education populations, either through *Flex Your Power*, or other mechanisms on the power and the incentives that are attached to Demand Response?

MR. SATCHWELL: One of the projects I didn't mention that we're engaged on is a DOE funded effort to look at a few select utilities that receive stimulus funding for the Smart Grid Investment Grant, agreed to undertake consumer behavior studies, so I'm looking at the intersection of dynamic pricing and technology and education. And we're sort of at the marketing -- we're assisting these utilities with their deployment plans, and I can just say generally that we've seen just in the marketing and the sign-up to get sufficient number of customers actually do a study, right? You need a certain analytical threshold. Education is by and large the key component. If folks don't feel educated about their choices for signing up for these programs, they're just likely not going to sign up, themselves.

COMMISSIONER PETERMAN: Mr. Hernandez, seeing that you're with PG&E, do you want to comment on this question Commissioner Simon raised just about outreach and diversity as it relates to DR Programs?

MR. HERNANDEZ: Yes. Thanks. I think part of it is, the fact that I'm still looking at the large CNI customer segments, we haven't quite seen exactly what that outreach would look like, at least based on some of the stuff I've been working on, so I might have to defer that to another PG&E person outside of this panel.

COMMISSIONER PETERMAN: Thank you.

MR. GRAVELY: Thank you. So we're going to let you continue, John, and give us a little update on PG&E and the other IOUs' program, and your thoughts on using DR for renewable integration.

MR. HERNANDEZ: Thanks, Mike. Again, thank you, Commissioners, for having PG&E speak on behalf of what it takes for DR to play a role in the renewable integration. And first off, I'd just like to start that PG&E is a big advocate of Auto DR, and OpenADR, we believe in openness, we believe that there is something fundamentally there that could actually carry us to the next paradigm, so to speak, about renewables and such. And we believe that DR is a good resource. However, currently, DR isn't meant to -- it's not meant to actually provide that level of service right now. And we are looking at different mechanisms to actually allow us to bring it across this new world. However, we do want to make sure that we strive for cost-effective Demand Response, and it's just not the program itself, but the entire end-to-end, from the customer all the way down to the ISO level.

Earlier today, there was a discussion about if DR is capable of going to the market. There are certain products that we can use, like proxy demand resource, however, as we currently undertake integrating those resources into the market, there's still ongoing procedures in the CPUC, it's the OIR, on direct participation, and we still need to figure out exactly some of the rules associated to that and before we allow third parties to actually hit the market. But currently speaking, PG&E is actually bidding in Demand Responses to markets. It's not substantial, it's less than two megawatts right now, but we are looking at how we actually could move forward.

My next point is, would renewables integration -- I believe customers can help, but it will take a lot of education and, to Commissioner Simon's perspective, it will take diversity of education, as well. And it's also the enabling technologies. I think we're only beginning to see some of that technology rise up on the demand side. And I believe it will take time. But we will figure out a way to bridge the two together. However, customers aren't really power plants. It's not meant to be a power plant. When they provide services to their end-use customers, it's not providing electricity, it's providing services. We need to understand exactly their capabilities from hour to hour that translate into Grid operations, and it's not just the ISO that we're talking about, it's also on the distribution side of the house, making sure that we have enough capacity to make sure that what we're providing from a DR perspective is not stressing the wire side of the house.

And last but not least, we believe that third-party projects are good and it goes, again, with education. Third-parties could reach out to customers that maybe the utilities may not be able to, and I think with third parties, it will provide us with better services and better understanding as to how we can integrate better into the market. And that's all I have for now until our discussion. Thank you.

CHAIRMAN WEISENMILLER: Thanks. Could you tell us what the status is of the direct participation of OIR at this point?

MR. HERNANDEZ: I think at this moment, it's awaiting on the Commission's hands right now. The DR, '12 to '14 just came out about two months ago and we're still waiting for the status on the CPUC as to when the actual working group starts again.

CHAIRMAN WEISENMILLER: Okay, when were comments or briefs filed in that proceeding?

MR. HERNANDEZ: I'm not sure. I might have to get back to you on that.

CHAIRMAN WEISENMILLER: Okay, if you can get back to me on the status, that would be good.

COMMISSIONER PETERMAN: Mr. Hernandez, from your comments, my take away is that, although we're seeing activity and movement in DR, there are certain barriers that will need to be addressed in order to have it at the scale needed for renewables integration, and you touched upon a couple, consumer participation, education, a better understanding of how to incorporate third-party vendors, and I was just wondering, assuming all that, what are PG&E's right now projections around DR, you know, for 2020? What role do you see it playing -- for fast response, in particular?

MR. HERNANDEZ: Sure. Actually, we're currently undertaking that particular analysis with Lawrence Berkeley as part of our '12 to '14 DR cycle. We've identified exactly what type of loads we should go after, for example, the refrigeration warehouse, more lighting, so we're still looking at exactly what type of end uses we need to go after and to project exactly the enablement and cost-effective technologies that we can incorporate and implement with that.

COMMISSIONER SIMON: Yes, thank you, Mr. Hernandez. I wanted to see if you could elaborate a little more on the stresses on the system that you spoke of in terms of Demand Response. What are examples of the stresses that you're concerned about?

MR. HERNANDEZ: Sure. For example, there could be potentials where we build up a resource at the circuit level, where it could provide regulation done, in this case, consumption-based in their response, which I think is not farfetched at all. If we don't quite identify where the line is, and whether or not it's already stressed out to begin with, the ISO cannot see below the network bus level, and this is really on the distribution side of the house, so we're telling customers, for a resource aggregated to a circuit level, to tell them to consume, that might actually be counterproductive to the actual wire side of the house. And so the question is, what are we supposed to operate under? Which jurisdictional rights do we have to say, "You know what? We cannot have you consume during this time because it's actually over-capacity in those lines." But yet the ISO doesn't necessarily see that, if it's seen as this deemed economical to dispatch.

COMMISSIONER SIMON: Then the DR or OIR, which is not assigned to me, and my Advisor, Rahmon Momoh is searching out Chairman Weisenmiller's questions as we speak, but is the OIR exploring those challenges involving the distribution side and the ISO's lack of, I guess, view or transparency in that?

MR. HERNANDEZ: No, it's not. This is just looking at direct participation of consumer rights, just making sure that we have all the proper rules associated to having Demand Response being directly bid into the wholesale market, so it's more of the procedure itself, rather than the operation, itself on the OIR.

COMMISSIONER SIMON: So currently the tariff is inadequate to address this scenario -- the tariff that you're operating under?

MR. HERNANDEZ: There is no current tariff, or at least any talks about revising tariff.

COMMISSIONER SIMON: On the distribution side.

MR. HERNANDEZ: Yes, well, right now, all DR programs that are currently managed by PG&E is under one tariff that is really more on the economic side of the house, the generation side, rather than on the distribution side. So it's aimed directly to reflect in the operations of the distribution.

COMMISSIONER SIMON: Thank you.

COMMISSIONER PETERMAN: We're just having a side bar about your comments, which is a good thing, I would just ask, if you don't mind, Mr. Hernandez, if you're planning to submit written comments, or to plan to submit written comments and just note some of these stresses. I know you talked about some response to Commissioner Simon's question, but I'd love to have that more in writing.

MR. HERNADEZ: Sure.

COMMISSIONER PETERMAN: Thanks.

CHAIRMAN WEISENMILLER: I think part of the question is that, I remember at one point PG&E was trying to target Demand Response in areas of its transmission or distribution system, where they were concerned because of load growth and all that they basically might be able to just defer capital addition, so those experiments were probably done, I'm going to say, about 10 years ago, or maybe longer, so certainly anything on that type of targeted Demand Response to deal with the infrastructure needs would be good to get in the record.

It's also interesting, obviously, that PJM has sort of driven this down to the 100 KW size, so, again, anything we can do to drive down the Demand Response programs to allow broader participation, would also be very good.

MR. HERNANDEZ: I'd just like to add, Chair Weisenmiller, that we are still investigating targeted Demand Response, mainly the distribution side, especially with new technologies like the vehicles that can provide Demand Response type of services. So we are -- we're still going with those efforts, making sure that DR as we know it is more surgical, it's no longer a DR where it's all or nothing, where it's addressing peak, it's really more surgical-based on the geographic and locational of certain stresses of the Grid.

MR. GRAVELY: Okay, thank you very much, John. So the next few speakers we have will be talking from the customer side, they've been providing DR services. And Anthony MacDonald, are you on the line? So Anthony is from Target and Target has been very active in California and nationally, so just one second. Anthony, are you on?

MR. MACDONALD: I'm here. Can you hear me?

MR. GRAVELY: We can now, yes. Feel free, you have the mic for now and go ahead and introduce yourself and tell us a little bit about what Target has been involved in.

MR. MACDONALD: Sure. I'd like to thank all of you for having me here. I'll briefly review what Target is doing around Demand Response around the country.

My name is Anthony MacDonald. I'm the key lead for Demand management at Target. I run our Submetering Peak Load Management and Demand Response Programs for the company. So Target has Demand Response at about 800 locations around the country, we participate in about 23 markets, are able to shed about 55 MW of load at any one time. We participate in utilizing OpenADR in California, working in the Hawaii program, Tallahassee, Florida, as that comes up, and then Duke Energy in Ohio, as well. We utilize ADR technology, that Constellation Energy has worked with us for about four years on, in about 400 locations, and then we utilizes semi-automated Demand Response and all the rest. And one of our big challenges as we maintain all these different programs, each one of those resides on our building main server and can cause significant issues if those applications aren't running, and maintenance pumps as we upgrade, so that's a big hassle for us, and different programs around the country.

We participate in capacity markets, economic programs in those markets, depending on the area. We're also looking at investigating additional inflow programs, currently we're looking at PJM to see what's available and what we can do. We are able to participate in less than 3 minutes currently and are hoping to improve our technology to do even better. And that's mainly a network speed issue on our side, so that's a big opportunity that we have to define.

Some of the biggest things we're really concerned about is maintaining guest and team member experience, we are a sales-driven organization, and our guest experiences where we really pride ourselves on our differentiation from different retailers in the country, and we really work to maintain that experience and, depending on the markets you participate in, the hours that are available, that has some drawbacks for us. And we also need to really maintain buying from our stores, our store teams, they're really important partners with us and if they feel that these programs create any drawbacks to the guest experience, or to their sales in any way, we get some significant pushback, so we've had to put some processes in place to really deal with those comments and make sure we do not have any store experience problems. It's also, we have to continue to maintain upper management buy-in and that can be difficult, especially as revenue projections have changed around the country. This year, we actually rolled more stores and more programs and revenue maintained the same, we didn't see a revenue growth, which is frustrating for some people. And so that's one of the biggest things that we're looking for, is consistency in programs and payments. I know in a fuller capacity market, that's not always the case, where at PJM we saw a decrease this year, but it looks like an increase the next two years, up next year, and then a little bit down in the following. And so we have to explain that, and it causes some headaches.

We also are looking for flexibility participation. As a retailer, we cannot participate 24 hours a day, our main loads are on from 8:00 p.m. to 11:00 p.m., and with using air-conditioning as one of those opportunities to curtail. We see peaks between noon and 7:00, so that really limits sometimes our ability to participate in those markets. And also, during the winter, the November and December shopping seasons, we're not able to participate at all in any markets, due to upper management constraints around the shopping season.

Another issue, running to our technical issues, we have one type of BMS equipment on-site, they're not always exactly the same, and so we really run into what the technology is and how we can utilize existing technology without adding new technology, which every layer of new technology on our stores creates more complexity for our store teams, our headquarters teams, and all our vendor partners that we work with in the field, and that can cause confusion, and which we try to eliminate.

And also, we try to make it standardized, these programs are across the country so that's not possible, so that's a real frustration when you're managing 800 locations across 23 markets in 30 some states, it becomes pretty difficult to manage some of our programs when they're so different.

And we're looking for this consistency in how these programs are managed, how they're operated, ability to use, like I said, our interesting hardware, and really engage with the different utilities, ISOs and RTOs across the country, to get feedback early and often from our partners, to make sure we're involved in some of those discussions going forward because, as this becomes such a -- our resources in our companies to propel some of our energy efficiency efforts, it becomes paramount, and as things change, it impacts our program and the buy-in we see from our management. Are there any questions for me?

CHAIRMAN WEISENMILLER: Yeah, I wanted to ask a question. You talked about trying to get consistency across the country among utility programs. How consistent are the programs within California, across the utilities?

MR. MACDONALD: Yeah, so we do see some inconsistencies in participation months, not all programs are available at all times. Payments are different, as well, in how often they control, so there are differences around those three items. Enrollment is basically the same, requirements are pretty similar, and ease of use is still there, but just differences in how often we could curtail and how often those programs are available.

CHAIRMAN WEISENMILLER: And I was trying to figure out, in terms of what we could do to increase your participation, what would it take to get your participation in California Fast Demand Response Programs?

MR. MACDONALD: So we participate in Demand Response at every site that we can, so enrollments in standard programs is not a problem, it's fast demand response probably around consistent technology, so I know in SCE, we can only work in -- we have 33 stores utilizing OpenADR platform, having that consistent across the state would be really beneficial and probably consistent payments, because some were less than others. As I said, we use the money as a resource for other energy efficiency projects, so having those consistent is very helpful. But Target, we're very forward looking and so, for the most part, we try to enroll where possible and we haven't been contacted as much as probably we could be on utilizing that sort of fast Demand Response methodology. We're signed up in standard programs for the most part across the whole state.

CHAIRMAN WEISENMILLER: Okay, thank you.

COMMISSIONER SIMON: Hi, this is Timothy Simon again. Mr. MacDonald, I may have -- please forgive me if I missed this in your presentation, but does Target operate through an aggregator? Or are you direct Demand Response?

MR. MACDONALD: So across the different markets, we work a couple different ways. So we work with multiple Aggregators where that makes more sense to limit our exposure on the down side. But also, we have direct utility relationships across the country, so we work a combination of both.

COMMISSIONER SIMON: Do you note any efficiency between one and the other from a comparative analysis standpoint?

MR. MACDONALD: Yeah, so working with the Aggregators is actually very helpful because it allows us to have them be the experts, where, while we have a team of four of us who spend time working on the Demand Response, it's not our only role, and therefore we can't know their program. Programs are constantly evolving and we utilize our Aggregators to be the experts for us, and work with the utilities on our behalf to get the best programs in place, and notify us of changes, and limit any down side. But working with the direct utility relationships, those have benefits, we usually are able to have a little closer relationship with the utility, and we get more direct feedback and maybe a little more flexibility in the program. But they both have their advantages, but we do for the most part like working with Aggregators because it really does limit our downside, which is very important for us.

COMMISSIONER SIMON: And as both direct and working with Aggregators, and being in different markets, in this case, particularly since it was part of our presentation, the PJM and, say, California, do you see any distinct characteristics between the capacity market and a market more like California where there are bilateral bids in terms of DR?

MR. MACDONALD: Not specifically, so the capacity market has a little more variation price because you bid that out three years. But that's really it. As we work with Aggregators in both -- maybe not in -- we do no direct utility relationships in either -- they're usually pretty consistent with our aggregator experience across both of them. There are some changes to PJM around utilizing PLC, the Peak Load Contribution information for minimum Demand Response levels for KW, that was a change, but besides that, since we use Aggregators, there isn't a whole lot of difference -- in our experience.

COMMISSIONER SIMON: Thank you.

MR. MACDONALD: In addition, sorry, we do have the ability to participate in different programs in PJM, though, so we participate in an economic program, a capacity market, and reserve program across PJM, where in California we only participate in the one program, the bilateral with our vendors.

COMMISSIONER SIMON: Thank you for that clarification.

MR. GRAVELY: Commissioner, thank you. Well, thank you very much, Anthony, we'll probably have some more questions just a little bit later. I'd like to go ahead and, Ron, you were introduced earlier by Scott Baker, so why don't you go ahead and give us a little bit of information about your involvement with Fast Response and DR.

MR. DIZY: Sure, thank you. I'll go through the first -- go ahead to the next slide -- the first few slides pretty quickly because this is obviously a skilled and knowledgeable audience. So we just sort of split this. To run a power market, you need energy capacity and flexibility. Next slide. There are ways for load to participate in all three of those markets. Next slide, please. So some markets allow loads to participate and there are some markets that allow loads to participate in their energy markets. We candidly think that, because loads in general use electricity to do something important, this will always be somewhat limited. Next slide. Most of what loads have done obviously so far, you guys have noted, has been in capacity markets, and of course, that's most useful where the markets are actually capacity constrained, which is kind of isn't true through large parts of North America now. And in your paid for availability, although you're seldom in a load actually curtailed, right, a few times a year. Next slide, please. So we think that the really big opportunity is, you know, broadly what I'll call "Flexibility," it's obviously different than capacity because it's about capturing flexibility in real time in how it's used. The other distinction is flexibility is always required in a power system, and of course, the need is growing more and more as we introduce more renewables and we retire parts of the generation fleet that used to supply that flexibility. At a big picture, we think this is worth as much as three percent of the electricity market. So it's a big problem that's worth solving. Next slide. And when we think about this, and I'll try to relate it to some of the conversation I've heard so far, we kind of map the opportunities on this chart. So these are things that we think that loads could do to offer flexibility into the power system.

The chart, the X axis is frequency of the requests, so if you could do this, how often would it be called; and then the Y axis is speed, how fast does it have to be called? One of the things I've noticed today is there's been a heavy emphasis on can loads respond fast enough, and I think that, clearly, they will be able to. I mean, at the end of the day, it's kind of an IT problem, and a little bit how fast can we get control for the load. It's pretty solvable. The real challenge is on the X axis, the frequency. So if you had the feature, how often would you use it? Because that's where the real impacts on the load happen.

So, you know, on the bottom left, we have what I'll call traditional Demand Response, curtailment four or five times a year, I've used the PMJ term, Synch Reserve, but that's operating reserve. In most markets, that's maybe a 10-minute product and it will be called, you know, two, three, four times a month, so 20-30 times a year. But, now you've got a way to integrate transmission connected to renewables, that's something you would use probably daily, maybe multiple times a day, so 100, maybe even thousands of times a year. If you integrated the distribution connected renewables, like solar primarily, you would end up using that thousands of times a year, and if you're doing something like grid balance, I apologize for the term, that's frequency regulation, that's every four seconds. And it really is every four seconds. It works out to 7.8 million times a year, six orders of magnitude more communication. And that's where the real challenge comes, when you want to use loads to participate in these markets, is how often they're going to need to be called.

And so the focus that we've had is how do we make loads do that. Go ahead to the next slide. And so our focus has been on essentially saying, if we can connect to load gen in real time, that's great, and things like OpenADR help with that, but they're just part of the solution. What we found is what we've really got to do is find ways for loads to participate on their terms, so offer their bits of flexibility into the system and then, frankly, have something in the middle that says, you know, I'll understand where flexibility is and you use bits of flexibility from different participants at different times so that, in aggregate, I supply something that is reliable, robust, and resilient. And that's what we've done from PJM, and you sort of saw the start of some slides that Scott showed. The idea is that, you know, we have discovered there are very very few loads that can and will be available whenever the power system wants them to be, especially if you're doing something like frequency regulation. But there's lots and lots and lots of loads that have some amount of flexibility, as long as they're allowed to say, "Hey, I'm not available right now." And these examples are water plants, or wastewater plants, or cold storage facilities, there's many many examples, and they sort of say, you know, within these sets of constraints, I have flexibility. But as soon as you go outside those constraints, you know, all bets are off. And the reality is, that has to be able to happen in real time. That has to be something that, you know, frankly, IT can do in real time. So our view is kind of, if we can capture those bits of flexibility in the power system, there can be nothing cheaper than IT enabling stuff that already exists, you just have to do it in an intelligent way. So that's what we do and I don't want to get too far -- what we've been doing, we've been logging PJM since November 2011, Scott mentioned the rule changes that PJM has recently -- well, through last year and this -- gotten approved at FERC, so they include everything from allowing smaller loads to participate to allowing submetering, which allows us to deal with smaller parts of big loads, you know, you can imagine a 20 MW car factory with 16 MW of conveyor and robotic load, and 4 MW of HVAC load -- the HVAC load is pretty controllable for something like regulation, the rest of it isn't. So you want to be able to submeter it so that you can provide flexibility without having to go back to the raw, just to the utility meter.

And then, other ones we're allowing, as Scott mentioned, regulation service provider only. So, you know, PJM has a very rich participation in those more traditional Demand Response programs. Many of those same customers would like to do regulation, and so what the PJM rule does is it allows them to participate in both of those markets with different providers. And all these things are important. I think if you guys are asking about rule changes, in many cases, they're not policies so much as they are needly administrative, you've got to get your hands dirty and figure out what's really stopping people from getting to market, and when you do, hopefully we're showing that you can make some big differences.

ERCOT and New York ISO are both making the rule changes right now that we think are necessary to see, substantial load participation in the ancillary services market, you know, in Ontario, you see at the bottom right, their market operates differently, they operate on a bilateral RFP basis, but that's changing in the coming quarter or so. And then we're starting to see -- we are working with New Brunswick Power using the exactly the same platform, but to provide wind integration, so it kind of shows the breadth of how far you can go if you can have loads participate in these ways. And I'll stop and happy to answer any questions.

COMMISSIONER PETERMAN: Thank you very much. We'll move on to the next speaker, but I'm sure we'll have some questions for the group at the end.

MR. GRAVELY: Thank you, Ron. So the next speaker is from EnerNOC, Rick Counihan. He's been involved in this market for quite a while and has both the California and national perspective. Rick.

MR. COUNIHAN: Yes, can you hear me, Mike?

MR. GRAVELY: Yeah, we can. You're good.

MR. COUNIHAN: Okay, sure. Chairman Weisenmiller, Commissioner Peterman, Commissioner Simon, thank you very much for having me on the program. I wish that I could be there in person with you guys, but I'll have to do the best I can. Let me first introduce EnerNOC a little bit. EnerNOC is a curtailment service provider, or an aggregator of Demand Response, and goes by many names, and we believe we're the largest in the world. We only work with commercial industrial customers, we don't do any residential work. We currently have 8,000 MW of load drop under contract, that's not total load, that's the amount of load that the customers that we have contracted with, if they all dropped load at the same time, it would be 8,000 MW. That's spread over 12,000 individual site locations across the U.S., in Canada, Australia, New Zealand and the UK.

Ron did a good job of trying to explaining the difference in terms of the kinds of Demand Response where there's this chart with the bubbles, we're obviously very active in emergency Demand Response, the provisional kind that is invoked typically for a specific emergency, a power line falls down, not enough (inaudible). We're also active in economic Demand Response when prices are high, and ancillary services, of which there's more than one -- spinning, non-spinning, load following, reservation, specifically, we've been active in PJM's synchronized reserve market, which has a 10-minute time (inaudible).

We're involved in a couple of things, we're involved with (inaudible) pilot with Bonneville in the Northwest, using cold storage facilities to follow the wind up and down, and when you get to these less than one-second response, we're involved in a program in Alberta where customers have to have -- you saw with their site -- under 350 (inaudible) that would drop their load if within four cycles, which is 460 (inaudible) a second if the frequency drops below a certain level. So it's about as fast as you can get, and it's so fast that it has to be done really literally right at the site, because there's no communication to send a signal anywhere.

So that's it. I had a couple of thoughts that I want to leave with you guys, or get to you guys, and one of them I've seen is that early on -- oh, you know, what, Chairman Weisenmiller, you were asking about the PJM thing, most of those resources, those 14,000 resources, have a two-hour dispatch, or a one-hour dispatch. And then their sync reserve has a 10-minute dispatch, and then that also talks about their regulation product. So, the point being, most of that has a longer dispatch time. But one thing I'd like to leave you, is if you use the right tool for the right job, that is to say, you don't necessarily need, you know, a 15-second response for all the changes in the load; in other words, with all the good work the Energy Commission has done regarding forecasting wind, forecasting solar output, some of these changes are literally known, you know, five, 10, 15, half hour, an hour in advance, and so a 10-minute product, a spinning reserve product, could be very useful in this situation. So you don't want to pay for more than what you really need, the job at hand.

The second thing I wanted to leave you with is that many of the barriers -- some of the Commissioners were asking about barriers earlier -- are the result of legacies of rules that have been created when nobody could imagine anything providing the service, except for a generator, and so we are left with these legacies like WECC, you know, it's probably not being around anything but generation to serve any of the ancillary services, except non-spin reserve, that's because when they first came up with the rules, there wasn't anything else to contemplate. Unfortunately, (inaudible) CAISO, they want telemetry like they have for the generators, well, you know, that's not cost-effective for a target store, or an individual rock pressure in a telemetry (inaudible), so we need to have communication agreements and rules that recognize the nature of the demand resource. And you know, the last thing I would say, at a very high level in

California, is one of the challenges that we face is that there is not a contention in the policy making community as to whether the CAISO could run the Demand Response market and allow third-party Aggregators like ourselves to bid into them, or the utilities being he procurer of Demand Response, that they could in turn provide the service to CAISO. And that unclarity [sic] as to the goals (inaudible) absolutely in California, and so you have a situation where, on the one hand, the California Public Utilities Commission apparently does not allow third-party Aggregators such as EnerNOC and a number of our competitors to participate directly at the CAISO. And yet, at the same time, you have the Division of Ratepayer Advocates suggesting that the utilities should no longer procure Demand Response because, clearly, the market is going to the CAISO. So I think that there is sort of a problem with the roadmap in California.

So the last thing I'm going to say is don’t forget the customer. A number of us, Andy touched on this, the customers need to be incented to do this, and it has to fit in with what they're doing. And Ron mentioned it, too, that not all customers -- customers don't have the same flexibility of a System Operator, but a group of customers can have a lot of flexibility and we have to always remember that, at the base of any Direct

Response resource, there are customers who are only going to participate if it's worth your while, you know, in a way that doesn't harm the underlying business, whatever it may be. So I will stop there and answer questions and take my direction from you guys.

COMMISSIONER PETERMAN: Thank you very much. I don't have any direct questions. I'll turn it to the Chair, any questions?

CHAIRMAN WEISENMILLER: Yeah, thanks, Rick. Thanks for participating. As you know, there's sort of a broad spectrum of potential Demand Response programs that provide different value, and I guess for today, in particularly on your comments, and in trying to focus more at the renewable integration, so that gets you to the quick response side. Obviously, part of it is, you know, if you're looking at renewable integration or, for that matter, the transmission line disappearing, you're shooting for a 15-minute window, so you really have to automate things very much, and part of the challenge always seems to be that, going from the ISO to the utility to the customer, and trying to do all things, too, I don't know how you could get there in that timescale. So I think all of us are trying to figure out, and again, there's probably enough different Demand Response opportunities, we can carve it up in a variety of ways, but at least for this segment of it, the renewable integration, emerging response stuff, I guess particularly in your comments now and your written comments, it's really what can we do that has more of a 15-minute timescale, as opposed to next day, or six or eight hours from now. So, basically, what would be the three big things to, again, focused just on that narrow type of Demand Response?

MR. COUNIHAN: Well, Mr. Chairman, a 10-minute response is very common, there's no -- there's very little technical barrier today to having a product that has a 10-minute response. So, things that could be done are CAISO could actually procure 10-minute Demand Response Program. Some of the utility programs do have a 10-minute -- most of them don't, but some of them have 10-minute response. We could encourage through the PUC, the utility programs to go more for 10-minute response. And the OpenADR work that the Commission has funded, and that is a very good electronic communication technology which facilitates 10-minute response, even many 10-minute responders can do it manually because a lot of the automation is all in the communications back and forth, and so if the communication comes from the CAISO and, say, an XML or an XMPT kind of format, it's machine readable, and EnerNOC's machine can read it, and end-use customers' machines can read it, and so the Management Systems can read it. And so I think the technology works easily for a 10-minute product, it gets more complicated when you're talking about the 10-second, the 15-second product, it gets a little more complicated.

COMMISSIONER PETERMAN: Thank you for that, and I think when we move to Mr. Keehn's comments, he can comment on that, as well, just in terms of -- I think you've explained it well -- that that product is available and it's just there's a difference across utilities, but welcome the ISO's thoughts.

Before we move on to our final speaker, we have a representative from the Public Utilities Commission here, Matthew Tilsdale, Advisor to Commissioner Florio, who is able to comment on the OII -- OIR, I'm not sure which it is -- at the PUC, related to Demand Response and just the latest status on that, since it's been a topic of discussion today. Matthew.

MR. TILSDALE: Thank you, I appreciate it. Good afternoon, everyone. A very quick update. My name is Matt Tilsdale, Advisor to Commissioner Florio. The assigned office leading the OIR in question, which is Rulemaking 701041, is President Peevey, and I just sent a note to his office and they gave us a little bit of explanation as to the status of the rulemaking, and Mr.

Hernandez brought up earlier, so the situation broadly defined, because this isn't my area of expertise, is that some progress was being made on this proceeding last year to set up the Commission's rules for what would be allowed in terms of aggregation of utility customer load and pitting of that load directly into the CAISO market. And I think that one of the tariffs was taken by the ISO, maybe Mr. Keehn knows more about this than I do, but to FERC and was rejected by FERC, or conditionally approved by FERC later last year. And that threw a bit of a monkey wrench into the Commission's rulemaking, and so the progress that was being made as of last fall is being brought back to the table now, and according to President Peevey's Office, it will be dealt with through workshops over the course of this summer with the intention to have a Commission, PUC resolution on the issue by the end of the year. So I hope that information provides a little bit more clarity to the conversation we were having earlier.

CHAIRMAN WEISENMILLER: Thank you.

COMMISSIONER SIMON: Thank you much.

MR. TILSDALE: My pleasure.

MR. GRAVELY: So this case has been for a while in the ISO, they have the last work, and Stephen Keehn will give us some information on the ISO's perspective on

Fast DR and Renewable Integration.

MR. KEEHN: And I don't have a long presentation, I just have a very short one. But let's move on to the first slide. This is just, when we're looking at Demand Response, and how we can participate in our markets and how we can use it, it's one of a number of tools we have. We balance markets and their participation from generation, and we see where storage can come in, and then Demand Response. And Demand Response can actually, you know, there are a number of different products, it can address a number of different types of needs. Our view is that, you know, we run the markets and the markets, if we set the markets up fairly, we believe that that provides the best incentive and the best -- accurate prices are going to drive what's needed.

With that in mind, you can see where Demand Response can address a number of different things such as peak load reduction, you can deal with some of the intra-hour variability, ramp smoothing, load shifting, those are kind of normal. We are trying to make changes to our markets to accommodate both Demand Response products, storage products, other types of products, in the best way, but one of the things that goes with that is also, I think as some of the people before mentioned, if Demand Response products are going to participate in our market, we need to be able to know that they will respond when we send instructions and to be able to measure what that response is so that we can control the grid. So the telemetry, the visibility and control aspects are very important and we're working on how we can do that, especially when a lot of the resources are maybe aggregated out, so there's not one specific resource, there's a number of different resources that we need to understand what's happening with. And when a lot of these resources are actually not directly visible to us, but are down on the distribution system, so there's a number of issues that that brings out, as the gentleman from PG&E pointed out, one is just visibility, the other is that there may be different needs for the distribution system vs. the transmission system. And those have to be coordinated.

So here are some of the things that we're doing to try to remove barriers to Demand Response and allow Demand Response to participate in some of our various markets. We have a Proxy Demand Resource Product (PDR), which would allow it to bid in and be treated as a resource; we've made modifications to our Ancillary Service markets that are removing some of the restrictions as to the type of resource, and obviously this is -- we can do this sometimes, sometimes it requires changes in WECC rules, or NERC rules, or some of that. We've also reduced the size of resources that can provide various services, I don't think we've gone quite as far as PJM, but we have reduced that a good bit. And we've reduced the continuous energy requirement, so for example, it used to be that if you were providing Reg up services, for example, you had to be able to do it for, I believe, two hours if you were in the day ahead market. Now it's been reduced to one hour. We also have in the real time market now that can be just 30 minutes, so that's allowing for more resources to participate in more of these different types of batteries and for Demand Response to participate. We also have something that we're working on right now, trying to develop, called the Non Generator Resource Model, it's actually being tested, we've got approval for it, we're just trying to get it to work, and these are allowing things like Limited Energy Storage Response and Dispatchable Demand Response to participate in markets by the way that we control them, they can -- so, for example, this is like a battery, for example, we would look at and maintain the charge on that battery, and this program would allow that resource to actually provide, say, Regulation service even though it may only have a small amount where it can move, we'll work at keeping it at its neutral point, and if we use energy out of it to provide regulation up, but in the next period we'll assume that it will be actually taking energy in, so we'll schedule that and, then, it allows it to provide this service over a much longer period of time, and more than maybe you would expect it to be able to do if it could just ramp one way or the other. So we're working on that.

We also have the Reliability Demand Response Product (RDRP), which is an extension on Proxy Demand Response, it integrates utility emergency demand response products. This is -- I think this may be one of the ones that was mentioned by the PUC -- we got a FERC ruling, but then, in kind of an overall FERC investigation, they indicated that Demand Response products should be paid the same market price as every other entity. Well, one of the -- our concept of that, actually the way we set up the pricing structure included making sure that we avoided double payment to resources, that they weren't being paid for providing energy, but then also not having to pay for the energy that they were providing, that could result in a double-payment to them. And the mechanism that we had set up with the PUC had specific mechanisms to avoid that double-payment. Well, it's run into some issues with this FERC ruling, and we're trying to work those out right now.

You can also see another thing we have up here is a Regulation Pilot we're trying to do with PG&E that was mentioned. And then the last thing I just want to point one thing out that would really help is if we had real time pricing, that would allow for demand to actually respond based on those prices, and one of the points where that may be really useful would be during periods of over-generation. One of the other things that we've just done is lowered the floor in our markets from -$30.00, it'll go progressively down to, I believe, it's -$300.00, so there may be periods of time where, if we have over-generation, this would typically probably happen at night when loads are very low and there's a number of resources that are not dispatchable. So, potentially wind, and hydro, in addition to the nuclear plants and other base load. You may see prices that go significantly negative. If those prices are going through to retail customers, they can choose at that point to turn on their pumps, or turn on their chillers, or something, and I think that’s probably one of the ways that Demand Response could really help.

All right, that’s all the presentation that I had at this point. I'm happy to try and answer questions and there are other ISO staff here who may know more about Demand Response, or specific programs within Demand

Response than I do, so we'll try and answer whatever questions you have.

CHAIRMAN WEISENMILLER: Great, thanks. How much load do you have in the direct participating agreements at this stage? I was going to say that my impression was that DWR was a big component a number of years ago, and it's sort of less and less at this stage.

MR. KEEHN: I think -- I do believe that they are the largest, I'm not -- I don't have the specifics. Peter, do you know?

CHAIRMAN WEISENMILLER: Well, if you could just submit that for the record later, that would be fine.

MR. KEEEHN: We will try and get that information.

COMMISSIONER PETERMAN: Regarding the ISO's work on the 33 Percent RPS, what are the assumptions in that work around DR?

MR. KEEHN: We're doing studies as to what we're going to need to incorporate that -- those resources, and part of what -- that work is being done with the PUC, and the PUC has set certain estimates of what energy efficiency and Demand Response levels will be in various scenarios that are being constructed, and then the ISO also looks at it itself and determines what our best estimates are of what things may be out in the future, then comes up with its own. But that's the way it -- my understanding is that a lot of those estimates are coming from the PUC suggesting things, which it's probably also being driven by the CEC estimates.

COMMISSIONER PETERMAN: Thank you. Any questions, Commissioner Simon? Chair Weisenmiller? We exhausted your colleague with a lot of questions earlier, so this is what happens when you're the second representing your agency. But thank you. So no more questions from us. In the interest of time, Mike, I would encourage you to wrap up, but if the panelists have any final comments they want to offer, and we also appreciate submission of comments to the written Docket, as well.

MR. GRAVELY: Okay, thank you. Any comments -- again, we talked before, but please feel free to provide any more detailed specifics. I think the deadline is a week from now, at least, to the docket, and we would appreciate any comments. Any closing comments from any of the panel members? Okay, thank you all very much. We'll swap panels here and the storage panel will take over.

COMMISSIONER PETERMAN: Oh, and I want to say, I think we were supposed to have a break at this point? Is that true?

MS. KOROSEC: Yes, but I am suggesting that we just -- people to get up and take a break as you need to, but we'll continue on because of time constraints.

COMMISSIONER PETERMAN: Okay. That sounds fine.

(Pause for set-up of Panel 4)

MR. KULKARNI: I am with the Electricity Analysis Office and this panel will build on what was learned in the last IEPR workshops, and possibly some of the things presented, so built on that. And this time, we will also include distribution site energy storage, a couple reasons, there is the Governor's Plan for 12,000 MW of energy storage on the distribution site, photovoltaics on the distribution site, and also renewable and distribution site, and also this morning you heard from Mr. Kroposki from NREL about some of the specific issues on distribution site integration, so hopefully some of those questions will be answered here. And more importantly, in the last year and a half, two years, many more distribution sites in the storage have come on-line, so there is some operational expedience which is also available, so hopefully the panel members can talk about that.

Our first panel speaker is Mr. Todd Strauss. He is a Senior Director for Energy Policy, Planning, and

Analysis at PG&E. Todd.

MR. STRAUSS: Thank you, Pramad. I'm glad to be here, Presiding Commissioner Peterman, Chair Weisenmiller, everyone, and it looks like unfortunately Commissioner Simon is on his way out. I know some of my remarks may be directed --

COMMISSIONER PETERMAN: His staff is still here, so I'm sure he will get the word.

MR. STRAUSS: And I appreciate this is a panel on energy storage, and PG&E has commented numerously in the past on energy storage and will have an opportunity to provide written comments after this workshop, so I'd like to take this opportunity to step back a bit and talk a bit more broadly, and in particular, following up on the theme that Chair Weisenmiller mentioned this morning in terms of the cross compare. That's actually critical when we think about renewable integration. And so, two broad elements, 1) a framework for thinking about that cross compare in terms of our policy, planning, procurement and operational activities, and second, a portfolio approach and, in particular, I'd like to talk a bit about what we might do, the Energy Commission might do, the Public Utilities Commission might do, what the State might do, in terms of the portfolio approach.

With respect to the framework, the policy in

California is technology-based, but planning in California is resource-based, and procurement is product-based, operations are asset-based. What do I mean by that? With respect to policy, we have a variety of technology silos, set asides, carve-outs, what have you. In resource planning, we actually think about resources, combined cycle resource, Demand Response resource, and think about resource alternatives. Procurement is about product, and actually one of the key issues for renewable integration, and our focus here ought to be, on the products that are needed, both in the ISO sport market and in forward markets, as mentioned earlier.

What we ought to be looking at is a suite of resource alternatives to meet those product needs. And in the end, the operational requirements, whether it's a gas-fired peaker, or a combined cycle, or a Flex-Unit, or Demand Response, or storage, or wind curtailment, or technology that hasn't yet been invented, that's what we ought to be looking for, and the question becomes, how do we create an environment in which those resources are able to compete in some sense on the market, and on the margin in some kind of market framework.

With respect to portfolio, the reason, one primary reason, that we have these carve-outs and set asides and technology silos, is that our regulatory framework does not acknowledge a portfolio approach. Each contract, each transaction, each program, must on its own, standalone, be cost-effective. That's no way to make an investment. It's on a portfolio approach. And thinking about the diversification, the low correlations that reside across portfolio elements, the learning from pilots and demonstrations, Lorie Bird earlier talked about geographic diversity, I'm calling about diversity on a much broader basis, that's actually the portfolio approach we need. And so if we insist that each and every investment, each and every transaction, each and every asset ought to be cost-effective, we will end up with a portfolio that, in fact, is sub-optimal. How do we deal with that? As mentioned earlier by Mark and Mark, that's Mark Rothleder of the ISO and Mark Smith of Calpine, and also John Kistle, markets, and market design, the spot markets of the ISO, has had the lead in designing and running, and forward markets, the resource adequacy market, the capacity market we do have, the one year ahead and one month ahead resource adequacy market, and there is a missing market, and PG&E for years has called that missing market to be developed, and that's a multi-year forward market, and that's the market that Mark Smith was called for, as well, and you acknowledged that politely when you referred back to -- Commissioner

Peterman when you referred to Mark Smith's slide and said, "Well, hmmm, with respect to existing resources, what's their going forward cost?" And so the issue still becomes, in that RA market that exists today, it's just one year ahead, that multi-year forward market that is needed, and not for just plain vanilla capacity, in fact, least for plain vanilla capacity, but for the operating flexible capacity and, again, to have Demand Response, storage, gas-fired resources, a variety of kinds of resources can compete to provide on a forward basis that operating flexibility. That ought to be our desired target.

Now let me try to comment on a variety of things that have happened so far today. Before lunch, there was a question called in regarding hydrogen and, Commissioner Peterman, you responded in terms of it being expensive and more costly. I just note that many people would say the same about storage. And we ought to think not in terms of cost, but in terms of value, the benefits relative to the cost, that ought to be our consideration for all resources in that market context. Mark Rothleder talked about a piecemeal approach, and moving from that to optimized on a broader basis, and that is the herald of the market approach that I'm talking about, it's not about a command and control central optimization, but allowing a variety of resources to compete on a forward basis, as well as a spot basis, to provide the kind of resource flexibility that's needed to integrate renewables.

Chair Weisenmiller, you focused earlier about 15-minute response in your opening comments. How much 15-minute response do we really need in California? Clearly, that's a Texas problem when, you know, West Texas, there's a lot of wind and they've experienced those kinds of problems. The how much question, I leave to the ISO and we've been working collaboratively with them to try to answer that. I just note that the daily ramping problem as pointed out in the slides that Mark had, Mark Rothleder had earlier, that, as best as we can tell at this moment, seems a problem at least as large a magnitude as the 15-minute response issue.

Rick Counihan of EnerNoc said don't pay, in essence, I'm paraphrasing a little bit, don't pay for more than the quality that's needed, so we shouldn't be paying for five-minute or 15-minute response if really intra-day flexibility is what's needed, and so we do need to have a finer granularity on the kinds of needs and just recognize that a variety of resources can meet the variety kinds of needs.

An observation now on gas-fired generators and storage. With a gas-fired generator, as the capacity factor increases, the ability of that resource to provide operating flexibility for renewables decreases. When it's fully loaded, and that's the point that Mark Rothleder earlier was trying to make, there's nothing left to move around, it becomes in essence a base load resource and there's nothing left to respond to operating flexibility.

Well, similar issues actually apply for storage with respect to the set point on that storage device, and the state of charge. And once thing I haven't seen much out of production cost models is, what's the mean state of charge over, say, the course of some year, or time period on a storage device? And I think we ought to be thinking about state of charge, mean state of charge, or maybe it's medium state of charge, some measures of state or charge along the set point to think about storage devices.

Mark Rothleder also mentioned passing along the cost signals, in particular, PG&E has called down a number of forums for cost causation principles, to pass along to those intermittent generators cost signals, and we support that. Cost allocation is critical to renewable integration issues. A question mentioned earlier by Chairman Weisenmiller about economies of scale. Can larger resources provide renewable integration? Is it better to aggregate that, rather than place it on every single intermittent device? Yes, but the market price signal should be on each of those intermittent generators and the physical device can be in one place, but the price signal should be dispersed.

And finally, to the contract question you asked me while I was sitting in the audience earlier, with respect to Tom Pierson of TAS Energy and the chilled water to increase capacity, an interesting and innovative technology, and so to some extent, it seems to me that effect, maybe he'd like duct firing in some sense, that is providing this extra peaking capability by chilling water. Well, valuing that is not a problem, the question becomes how does one modify existing contracts with respect to that? And this is one of those issues where utility-owned generation does not have that issue so much, it's something we've pointed out, PG&E in 2006 and 2008, why? Because the real option is to modify the existing asset. It can be done with an existing contract, but Chairman Weisenmiller, as you know, over your course of years and decades dealing with qualifying facilities, modifying those contracts is possible, but challenging and that's the kind of situation we may face with respect to some PPAs, some Power Purchase

Agreements, in that chilled water technology.

So with that, I'd like to conclude by, again, just highlighting the two points I'd like to make with respect to our framework of policy, planning, procurement and operations, we need to move from a technology silo, carve-out, set aside basis in the policy space to a market-based competition in the product space, and that's the kind of environment that this Commission and the State of California should be encouraging. How to do that? With techniques, methodologies and approaches that would encourage a portfolio approach, so each asset, program, transaction is not valued on its own standalone, but in that portfolio context. Thank you and I would welcome your questions.

COMMISSIONER PETERMAN: Todd, thank you for your comments. You provide a lot of food for thought, I think we could almost have a philosophical discussion about regulation and such, and accordingly, but appreciate your comments. I'll just ask a very focused question, and I'm going to turn to your slide 3, I think you may be the only panelist we've ever had who has not used their slides, so well done. And I know this is -- especially from a utility, you had three and you didn't even use them, that sets a precedent -- so I know this is meant to be conceptual only, but looking at this conceptually, so we have energy storage out here on the far right with a higher cost and you commented on the value of comparing a suite of resource alternatives, which is truly important, and so it would be good to hear more from you about, at PG&E, how are you comparing these suite of alternatives, and also to the point, you made the point that we need to think about value and not just cost, so if you could speak to what additional value we may be seeing from storage that would compensate for the higher costs, it would just be good to have your insight.

MR. STRAUSS: Sure. And just note that the vertical axis is not simply cost, but net cost, so we're trying to take into account, in essence, the market valuation pieces that we do see, so energy, capacity, ancillary services, so to that extent. And frankly, with respect to the quick response kinds of elements, the regulation, that kind of storage, I mean, one of the key issues is, what's the forward market for ancillary services? We don't see one. And so, as I provided in testimony on at least one application that PG&E had for a pumped storage project, there's a wide range of uncertainty associated with ancillary services, and that's a key driver for utility scale energy storage. You can do the back of the envelope calculation, but basically when gas prices are $5.00 and MMBTU, and a peaker is providing a 10 heat rate, that's at $50.00, if it's got a set point in the middle and it's going up and down, it's $25.00 MWH, right there, in terms of variable cost to provide that regulation over that course of the hour, multiplied by four-thirds right there, is kind of your breakeven for storage, so if the market energy price differential is less than that, then basically storage can make it up in the variable cost. The key question becomes on the fixed cost, the capital cost, and right now, you know, that's really the biggest hurdle for utility-scale storage devices and even more so for distributed generation, a distributed kind of storage, and so that's why it seems in the portfolio approach the way to approach it is small-scale pilots and demonstrations to kind of ride through that cost curve. On the renewable picture, this is where we were with renewables in 2005 and 2006, what solar technologies would emerge as champion. And no one, I think, had counted on Chinese subsidies to help us with renewables, but that may really help provide the diversity of energy storage we need right now.

CHAIRMAN WEISENMILLER: Yeah. So a couple questions. It seems like one of the difficulties obviously in the production cost modeling side, trying to get storage right on a forecast, at least I haven't seen the models do a very good job on that, you know, you're sort of looking off the margin, on the margin. And I don't know if in terms of the PG&E system or the analysis you guys have done there if you're comfortable, again, on those sort of assessments of storage.

MR. STRAUSS: Definitely haven't seen any production costing analysis that hits the right granularity with storage and really takes account of the state of charge, the energy limits, if one would.

CHAIRMAN WEISENMILLER: Right.

MR. STRAUSS: And algorithmically, that's a challenging problem. We actually have a variety of kinds of storage valuation models that take that into account, we spend, you know, decades dealing with large-scale hydro, but we've recently been able to do that for compressed air, and energy storage, and increasingly for battery storage. The question becomes how does one integrate it into a system kind of modeling the production costs, the kind of models you point to. And I think that's actually an area where there is an opportunity for the Energy Commission to take a leadership role because there clearly is a lack in our state-of-the-art modeling to handle these kinds of issues. I agree.

CHAIRMAN WEISENMILLER: Well, the other

question is, obviously one of the differences among the different storage devices is basically the ramp rates, and certainly thinking back to one of Roy's presentations a couple years ago, arguing that, you know, rapid ramp rates were very important and leading us to more of a focus on compressed air or pumped storage, as opposed to batteries. And I don't know how in the modeling anyone has made much progress in teasing out what the characteristics we need in terms of ramp rates for storage.

MR. STRAUSS: With respect to the system need, I would again defer to Mark Rothleder and the ISO. We have been cooperating with that and that's a challenging modeling effort. With respect to valuation, I just note that we've run a number of RFOs for conventional gas-fired resources and we're beginning to be able to pick out the differences in value between a 5 MW ramp rate and a 15 MW ramp rate and a 25 MW ramp rate, beginning to pick them out, beginning to see the differences between the valuation of Demand Response that's day ahead flexible vs. day of flexible, so these elements can be picked out with increasing effort. And, again, I would suggest that's an area in terms of modeling and methodology that the Energy Commission is well primed to take a leadership role in.

CHAIRMAN WEISENMILLER: Okay. And in terms of talking about the procurement process that's more attribute-driven, I mean, back to the same question I asked Mark, is are there any good examples around the country where people have a procurement process that actually does layering, at least into a plausible fashion that might get you the right outcome, in terms of attributes?

MR. STRAUSS: I mean, we want to be careful what you mean by "procurement process," but I'll point to an example. PG&E has run a number of intermediate term RFOs, so looking out into that missed market, but looking forward to one to five years forward, and we've had a number of products compete, including products that provide just resource adequacy, providing a variety of kinds of energy, providing a variety of kinds of tolling, and we've been able to kind of compare them side-by-side and head-to-head.

If you're talking about procurement in really a planning context, and I think that's maybe where you're talking about, I'll call it planning and not procurement, and that's an important distinction, where we then basically have production costing type models, and have stylized generic resources we're putting in, and thinking about those contexts. We're trying to actually look around across the country and across the world for good examples of resource planning that takes these elements into account and we are open to approaches. I just note, again, at the Public Utilities Commission, it's rather a rigid framework with respect to resource planning, with respect to planning assumptions, scenarios, and so forth. So what I think we need is something that's a bit more flexible. And I know I've been here before at the Energy Commission talking about that portfolio approach in resource planning, as well.

CHAIRMAN WEISENMILLER: Okay. The last question I had is, thinking about, you know, the proverbial capacity market question, is that obviously that's been something that's bounced in and out, I think the last time it was sort of looking close, was where PG&E was on the flip side of that, more on the bilateral, but, again, the question is how do we deal with some of our basic issues in the state in terms of the market structure, without some sort of capacity payment in a capacity market?

MR. STRAUSS: Sure. You may have not been here at the beginning when I called for a multi or forward market. That's actually something PG&E has called for, for a number of years, and we're aligned with many of the market participants. Now, I just want to make the distinction, we do have a capacity market in California, it's resource adequacy, it's year ahead, it's local, it's month ahead, it's not multi-year forward. It's bilateral, not centralized. But actually, the fact that it is bilateral and not centralized is secondary to the fact that it's year ahead and not four or five years forward, so there's actually that multi-year forward payment. And to some extent, you look to see Demand Response; the issue is not that the ISO doesn't have a forward Demand Response market, the question is what would the price be paid. And when the utilities are willing to pay $85.00 KW year, it doesn't matter if the market price for RA may be $20 or $30 KW year. It's that forward payment price, as well as the market structure that's very important for enabling all kinds of resources.

CHAIRMAN WEISENMILLER: Okay, thanks.

MR. KULKARNI: The next speaker panelist is Jim Eyer. Jim is with Strategen and before that he worked for Distributed Utility Associates, and he has written several reports in collaboration with DOE and Sandia National Lab, on the valuation of storage and cost and characteristics. Jim Eyer.

MR. EYER: Thank you very much, Pramad. On behalf of the California Energy Storage Alliance, I would like to thank the CEC for the opportunity to participate in this important workshop. I'm Jim Eyer, as Pramad said, I'm an advisor and consultant to CESA and for Janice Lin's Consulting group, Strategen. I'm a bit scripted today. If any of you have heard Janice speak, she's a very challenging person to try to duplicate, so I'm going to make sure I stay on message with my written comments here.

COMMISSIONER PETERMAN: And, Jim, I'm going to ask you to focus particularly on -- I know there's a lot here in your presentation, all storage, generally, but particularly the question at hand today, which is the ability for storage to meet some of our renewable integration challenges.

MR. EYER: Okay. Well, yeah, my comments are a little bit broader as far as storage goes, but we definitely want folks to know that an important takeaway from the presentation is that CESA challenges the notion that storage is not cost-effective. Indeed, we don't know whether storage is cost-effective primarily because the benefit streams haven't been fully quantified, as we've heard and, of course, cost-effectiveness depends on those benefit streams. So what's exciting about storage is that a single storage asset can provide numerous benefits, so even "expensive" (in quotes) storage can be cost-effective.

Another key point is about optimization across the grid, including supply, transmission, and distribution, and behind the meter. Given all that, another takeaway is that an inclusive applications-based approach that we're going to hear about from the CPUC later is needed to fully evaluate the cost-effectiveness of storage.

So perhaps the key outstanding question is, how will stakeholders be paid for the services and benefits delivered? A related question is, how certain will those cash flows be? And we've heard allusions to this today already. So what is needed to realize the exciting potential of storage? Well, we think that we needed to establish prices that reflect benefits and we need compensation mechanisms that attract investment and cost-effective applications, for example, multi-year forward markets for capacity.

So the next slide is just a listing of the members. CESA members offer quite a diverse suite of storage technologies and systems for a wide array of applications. And I think that's an important theme, there are a lot of different storage technologies that can do a lot of things.

CESA's mission, quickly, is to make energy storage a mainstream energy resource, one that accelerates the adoption of renewable energy and that promotes a more efficient, reliable, affordable, and secure electric power system.

And some four key CESA principles that Janice wanted me to mention are that we do -- we're focused on further adoption of renewables, very consistent with this workshop, collaboration and coalition building, especially with utilities, and she's done a really wonderful job of that, healthy electricity markets, again, we've alluded to that, and diversity in terms of technologies, locations, and ownership models, so there's that portfolio theme again.

I won't dwell on this next slide very much, but, again, this is just to reiterate the point that storage can do a lot of things and it can be used throughout the Grid. With that in mind, CESA's coalition represents all forms of Grid storage, large-scale, pumped hydro, mechanical, chemical, and so on. So the key point is that a diversity of storage types can satisfy requirements of many applications.

And this addresses -- this is our crack at talking specifically about what storage can do with respect to renewables, and the next five slides are mostly operational in nature. So, for both renewables, storage can be used to manage the daily mismatch, we know that, between renewable generation and output by firming the output so it's constant and by time shifting energy so it's more valuable. Storage is also good at addressing generation variability by providing longer term ramping and shorter term frequency response services that are far superior to generation capacity because of the ramp rates.

And interestingly, storage can optimize operation of the conventional generation fleet which facilitates renewables integration directly. The folks at EPRI have done some work on that, that called this "Dynamic Operating Benefits," so it's helping the grid operate in a more efficient and optimized fashion. Storage can also be used for energy balancing, of course.

Down on the distribution level, this slide shows ways that storage can help integrate distributed renewables, which seem likely to be dominated by PV for the next few years, at least. So storage can be used to address that daily mismatch between PV output and demand, time shifting energy, and firming the PV capacity output. Storage can also address localized ramping-related effects, especially voltage fluctuations and energy production in excess of local demand to avoid the backflow current through the system, it's designed to go one way.

More broadly, storage can address other localized voltage and reactive power-related challenges, and even harmonics associated with high PV penetration. And storage could serve as a hub or a key enabler of islanded or microgrid solutions and operations. I won't dwell too much on this next list, these next two slides, but what I wanted to do is at least give a full accounting as far as I know of all the benefits.

One of the questions asked was, what are the other things that storage can do beyond the renewables integration? So I wanted you to at least have this as one menu of benefits and, interestingly, just to digress for a minute, this work, the genesis of this, was back in 2003 with Mike Gravely when we were encouraging the vendors to come up with proposals for value propositions, as opposed to technologies. It was a partial success, but I think that's an important theme going forward; we're not in the technology business, we're in the solutions and products business.

And the columns indicate whether or not location matters, and these are my slides, so this is my opinion and it's based on that Sandia work that Pramad mentioned.

The first list was really the more familiar ones, the ancillary services and the electric supply, and then the end users.

Getting down into this next slide, I've got several -- I've got three line items I cull out for renewables, but I also want to cull out what I call incidental benefits because, in the big picture, they're really important considerations for the storage story. For example, T&D I^2R Energy Losses, which affect fuel use and peak capacity needs, increased utility generation, transmission and distribution asset utilization, which is kind of a sleeper issue for us, and I think it's an important societal benefit, and then reduced fuel use and air emissions per KWH delivered, if we can optimize the system better. So these 32 benefits that I've just culled out are building blocks for value propositions, or applications, meaning that they can be combined so that the benefits exceed cost.

Now, in the next slide, this is just one example of an inclusive application-based approach with looking at the assessment of storage applications that incorporate these benefit building blocks. The benefits are on the vertical going on the left side, and then the applications go across the right, so there are several of these, including the Electric Power Research Institute, Southern California Edison, and most recently the really good work that's being done over at the CPUC.

And CESA contends that, without such a framework, the value and importance of storage is likely to be understated. Now, the next slide --

COMMISSIONER PETERMAN: I just have a quick question, I'm trying to look closely at this. What would result in a tertiary benefit? I was trying to see what -- so I get what the primary benefit is, so what defines a secondary benefit and what defines a tertiary benefit?

MR. EYER: Well, it's somewhat of an arbitrary distinction, but it's ones that aren't necessarily -- there's no price, that it doesn't look like there would be a market price for it, I mean, I^2R losses are real, but it's sort of absorbed in the rate base and all at -- I mean, at the end of the year when we reconcile the revenues and the costs.

COMMISSIONER PETERMAN: Okay.

MR. EYER: So in contrast to the previous five slides addressing operational facts of storage, this one provides another perspective on renewable integration from a project development standpoint. This is really key, honing in on how to compensate storage owners for the benefits delivered.

Okay, on the next slide, the key message we want to convey here is that the type of ownership involved can have a cost-effectiveness for a given application.

COMMISSIONER PETERMAN: I think we're one slide behind you.

MR. EYER: Okay. So an example is behind the meter storage, which is utility-owned, like the SCPPA model, vs. end user or third-party owned. In that case, the same equipment at the same site delivering very similar benefits may or may not be cost-effective, depending on regulatory treatment for different ownership types.

So in conclusion, storage is diverse, technically ready, and is getting better all the time. Next, we probably need more innovation and we definitely need more evidence that can only be derived by demonstrations, especially with respect to storage solutions -- and I put "solutions" in bold here -- including software dispatch storage for optimized benefits and then, secondly, electricity market design with modern rules, ease of access, and long term contracting that accommodates the range of ownership models. And fortunately, the CPUC is making some excellent and timely progress in that regard.

And finally, here is CESA's call to action for the CEC. Clearly, the CEC can play a significant role with respect to enabling utilities, end users, and third parties to learn by doing. As you consider doing that by, among other activities, enabling public interest innovation, 1) that leads to storage system solutions that are optimized across the grid, and 2) systems which address challenges related to our increasingly acronistic electricity market design, and 3) efforts that encourage and demonstrate cost-effective applications and ownership models.

CESA urges that CEC to provide analytical and technical support for the PUC's storage rulemaking, especially with respect to benefit quantification for cost-effectiveness and valuing the flexibility of storage. And in general terms, the CEC could incorporate recognition of storage as value in decisions about conventional and renewable generation. The CEC could also encourage inclusion of storage in California's resource loading like we see for Demand Response, and -- this one got a little garbled, but this is harkening back to the CADER effort, the California Alliance for Distributed Energy Resources, it seems as though some sort of interagency organization like that would be really helpful, so we can all be on the same wavelength; even jargon can get us into trouble sometimes. And I echo the statement about the production cost models, I think there's a lot of work that could be done there to enable us to get a better handle on the benefits and how these can help us out. Thank you very much. Oh, I just wanted to make one more statement, Janice is always open for questions and discussion, she's really got her hand on a lot of the knobs in the storage realm, and I would encourage you to take advantage of her knowledge and insights.

COMMISSIONER PETERMAN: Thank you very much. You were able to condense a lot of information in a reasonably short period of time, so appreciate that, and I also appreciate the backup slides. You mentioned market design as an area that needs to be improved and I don't know if others -- we don't have a representative from ISO on this panel -- but we talked in the last panel a lot about market design and some of the barriers for DR, and, Todd, maybe you have a thought on this, but are the market design issues the same for storage as they are for DR, as we identified, or are there some unique ones that are facing storage? I appreciate that there's overlap, I'm just trying to get a sense of if we've identified the set of market barriers, market design barriers.

MR. EYER: I would say yes, but my response is a little more nuanced. My personal preference is for a technology neutral framework, I really think that's the way we should go about this. As much as I love storage, I'm personally not interested in special treatment, we'd like to get a market design that sends out the right price signals. Ed Cazelet, formerly with the ISO, for example, argues for a four-second price signal, if you keep sending out a four-second price signal that goes out really fast, this might eliminate some -- a lot of these market design issues and, if you don't get the right response, then the price signal might be wrong.

COMMISSIONER PETERMAN: Thank you. And I would say I'm also supportive of a technology neutral approach, although I think, when we do design approaches that way, and then there's a technology that feels disadvantaged, and then they start calling for a technology specific approach. And so I think it's all good to say technology neutral, but there can be unintended consequences than with a more general framework.

MR. STRAUSS: If I could just follow-up to your question. I mean, an example is, you know, a regulation product and allowing a resource -- an asset that has a set point of zero to provide regulation, that's an issue very much more for storage than it is for Demand Response. To some extent, for Demand Response, we've been very successful in California with various kinds of load control and, you know, the switch currently off and connected centrally, but you can imagine a device that's based upon price signals, and if the -- so it doesn't have to be manual, or phone calls, you can imagine devices of the future that would respond to four-second price signals and if those devices were distributed within that home area network, then that would enable the demand side to participate in the same kind of way. It's an example of a flavor that would be different for Demand Response from storage.

MR. EYER: And just one other comment, a lot of the potential for storage is down in the distribution system in lieu of other types of capacity, and in that case I'd like to see the capacity expansion approach be more inclusive and allow for resources like storage, you know, someone is going to have to say, "The storage has to provide this much power over this duration, that's what we need in this part of the distribution system." If the utilities had the flexibility to do that, rather than just say, "I'm going to build a wire to make up the difference," I think storage would be put in good stead.

CHAIRMAN WEISENMILLER: Just one question. Do you anticipate economies of scale in storage?

MR. EYER: I think that some plants do get economies of scale, but I think, as with the other modular distributed type technologies, we're talking about economies of production or economies of manufacturing, and I think that's where we're going to have the cost reduction. The transaction costs, I'm not very familiar with doing smaller ones, but I know that can be pretty burdensome, as well. So I think there's some transactional economies of scale, but that's being addressed by Demand Response and the Aggregators, too.

COMMISSIONER PETERMAN: Dr. Helman, you look like you had a comment on this discussion?

DR. HELMAN: Yeah, this is Udi Helman of BrightSource, but I was also at the ISO before I moved to BrightSource. And just a cautionary note on the market design solution, you know, you can create new products or maybe change the pricing mechanisms for existing products, but renewables will be displacing a lot of gas from the power system, there will be a lot of unloaded gas power plants on the system that have a lot of certified regulation capacity and can provide a lot of response. So it's not guaranteed that the price of these services is going to go up substantially, even if you define new products -- at least not for the next, you know, little while as we see how the system reacts.

MR. KULKARNI: The next panel speaker is Dr. Ali Nourai. He is Executive Consultant with AEP and

KEMA, but more important than before that he was for 30 years at American River Power and he started there he worked on the distribution side issues and specifically to the energy storage as a solution for some of the issues that we were facing, and contributed actually to develop the utility Storage which was adopted by EPRI and some other utilities. Dr. Ali Nourai.

DR. NOURAI: Good afternoon. I think based on what I heard that there's no point for me to talk about energy storage as a solution for renewables. I would rather talk about what can we do to make energy storage viable, and specifically on an economic scale.

COMMISSIONER PETERMAN: And, sir, would you mind pulling your microphone a bit closer? I just want to make sure everyone else gets to hear you, as well.

DR. NOURAI: We can go onto slide 3 directly. I installed a lot of energy storage when I was in the utility. In fact, 11 MWs and five different substations. At the substation level, energy storage is beautiful, it does wonders, it was great, but it was not good enough. It didn't answer a lot of issues. Because of that, we figured out, in order for energy storage to be even better, it has to have two main qualifications in order to be economical and in order to be viable, 1) a requirement is that it has to be put in the right place and one of the reasons I think that, the closer to the edge, or the closer to the customer, is as high as the value is because of the renewable. In AEP, when I was working during the last 10 years I was there, every year the renewables was doubling right at the house and we couldn't -- it didn't matter how much energy source you put in substation, it didn't help. You had to go to the customer. So location isn't the most important thing as far as increasing the value. The second requirement is it has to be packaged in a way to reduce the costs, economy of scale, in other words.

When we installed energy storage in substation, about 17, 20 percent was non-repeat cost, every single project did non-repeat cost, and I looked at the future, it's going to be like that forever because they don't lend themselves to standardization, they don't lend themselves to competition, they don't lend themselves to commodity pricing. We have to design storage in a way that it yields itself to be like a major, like a transformer, where utilities buy not hundreds, not thousands, but millions of them. That's the only way to bring the storage down, the cost of the storage down.

So if you look at the next slide, this is Requirement 1, the location in order to have the highest value, it has to be as close to the customer as possible.

This side of the meter, or that side of the meter, there are a lot of issues about that, but the point is the meter, that location, is the highest value and I believe the utility side of the meter, because of some of those reasons mentioned there, would even give you the higher value.

Now, the next slide talks about a platform. It's a technology neutral platform. That was basically my parting shot (ph) when I left the utility, that if you want to have a future, this is the package, this is the direction to go. You either go into highly mobile, trailers or shipping containers, which yields itself to standardization and mass production, or you go even further down to distributed at the edge of the grid, right at the transformer that heats your houses, put it next to that transformer -- we call it Community Energy Storage. And before I left AEP, they actually started a project like that, a two MW worth of these little boxes. Detroit Edison is doing that and, as I will show you on another slide, a lot of other utilities in the last few years have started to jump at it because they recognize a lot of values, which I don't want to sit down and enumerate them for you, but they definitely do the best when it comes to renewable at the residential. They do the best offering because it solves the problem right where it is, at the edge.

If you go to the next slide, it just is a simple description about what Community Energy Storage is, it pairs or matches the transformer which services several houses, and it handles the renewable right there. Aggregated, it handles renewable at the substation level. Aggregated further, it addresses renewable and other benefits at the system level, it can do it all, and that's why the closer to the grid, to the edge, the higher is the value because the aggregation allows you to roll up those benefits all around the system.

If you go to the next slide, there are a lot of benefits that Energy Storage can do and Community Energy Storage can do, and I don't want to enumerate them because Jim went into a lot of that, but certainly EV charging and renewables are the two challenges of utilities today, can be handled with that.

And the next slide is really my pride. Four years ago, I suggested Community Energy Storage for one main reason -- competition. To allow competition, the storage doesn't go anywhere. And in four years, there are about 12 manufacturers of Community Energy Storage at about two dozen utilities trying that around the world, most of them in California, and West Coast, I should say, but all over U.S. and globally, utilities have accepted the concept of Community Energy Storage -- again, because of many values to them. The most important value from a utility point of view, as well as the manufacturer is the starting cost is low. And substation storage and higher requires millions of dollars of funds. Community Energy Storage, you can start under $100,000; if you like it, you can add to it gradually. Its flexibility allows a lot of these utilities to get started easier.

The next slide, these are eight of the 10 manufacturers that are already making Community Energy Storage, within a few years, they started to compete. Two more, they didn't want me to mention them, but they will be out by the end of the year. Competition is the key for bringing the price down and mass production.

If you go to the next slide, this is a general opinion about where we are and where we need to be. The price -- again, Community Energy Storage is a platform, it's technology neutral -- regardless of what technology we put there, we are around $3,000 KW for a few hours, one, two, three hours. It needs to be under $2,000. The Discharge Duration, today because of the cost and size, is around one to two hours, but it needs to be closer to four hours. Efficiency is around 80, but it needs to be about 90 percent. Visible size needs to be smaller because it goes into neighborhoods. And the technology, again, today lithium ion, flow about three, other ones being used, in the future I believe more compact and less expensive, storage will replace that.

So in the conclusion, the two requirements to make energy storage happen, 1) it has to be allowed to be put where the value is the highest, the more broadly distributed and closer to the edge, the higher will be the value; and the second thing is, it needs to be in a package that allows competition and allows mass production in numbers, economy of scale. And, again, just like a transformer itself, it has to be almost like a commodity price, otherwise for years we'll sit around meetings like that and talk about why storage doesn't happen. And that was basically my conclusion. Thank you.

CHAIRMAN WEISENMILLER: So the basic question, obviously these numbers, if you do the aggregate, become pretty large in terms of dollar impact; so the question is, at this stage to go from your current to goal, do we need technology breakthroughs and/or do we need economies of scale, or do we need both?

DR. NOURAI: It is all of the above. The technology impact is really to make it smaller and more acceptable to do in a community, this is not -- of course, at a lower cost, a technology comes, that would be great. It's a cost issue. So one of the key things, and that's my request for all Commissioners, is allow utilities to look at it as a solution, and ask them where is that kind of broadly distributed solution because allowing that to happen is the trigger for thousands to happen.

CHAIRMAN WEISENMILLER: But you have to figure out -- it's a solution, but the question for the utility is, what is the value? So I guess the question for Todd is, I don't think anyone has ever told Todd not to think of storage, but the question is, have you been able to identify the value.

DR. NOURAI: The value Jim talked about --

CHAIRMAN WEISENMILLER: I'm asking questions of Todd.

MR. STRAUSS: The answer is yes, the question is expected value or the huge range of uncertainty associated with that value, and that's actually the big issue in thinking about storage on all scales going forward, is it has far greater uncertainty associated with that value, or that expected value calculation, than many other assets available right now. And we just need to recognize that. And there's room in the portfolio because, you know, because of that fact.

CHAIRMAN WEISENMILLER: Yeah, no, I mean, if you've gone through all the various characteristics, I remember at a conference I was at where someone was talking about all the different factors they took into account to do a bid for a power plant, and I was sitting next to a banker and he said, "God, they must have overpaid." And they did, they ultimately went bankrupt. So, I mean, the complexity has value where you're taking into account additional factors, but we also have to be careful not to be confusing ourselves on what the real value is. So, anyway, next speaker.

MR. STRAUSS: And just to add, you know, double-counting is a real important consideration when there's a long list of 32 attributes you want to piece out, you know, what's the value with which component, and are there opportunity costs associated with, you know, attribute no. 11 and 32, because otherwise it's very easy to double count.

COMMISSIONER PETERMAN: I just had a quick follow-up question. On your slide about utilities exploring CES, I was just wondering if you had any numbers to put around that. And so they're exploring it, but it's a demonstration project, how many megawatts in total are we looking at?

DR. NOURAI: AEP has two megawatts; DTE has half a megawatt; other ones are most in the order of two, three boxes, which is exploring, in fact, that's one of the reasons they do that, because to a explore a substation battery, you need $3 million; to explore this, you need $100,000, and that's why they're more willing to go in this direction.

MR. KULKARNI: The next panel speaker is Charlie Vartanian, with A123, with a Battery Manufacturer. And I think Charlie should be able to answer some of the questions raised earlier about Laurel Mountain and intuition with wind and also possibly with the Huntington Beach energy storage with AES. Before he went to A123, Charlie worked for many many years as a Distribution Engineer with Southern California Edison. So I think he is familiar with both sides of the -- the distribution side and product availabilities.

MR. VARTANIAN: I'd like to thank the Commissioners and the CEC staff for this opportunity to participate today. And my focus will be -- I'll call it a message from the trenches, what is some of the early experience by our company, and I'd like to qualify that I believe it's representative of advance energy storage, in general. Our accomplishments are mirrored somewhat across the industry with a number of manufacturers, so this isn't unique to A123.

A real brief bit of background. Prior to distribution engineering, I did do about 20 years of initially generation planning, then market planning, and transmission planning for an IOU here in California, and that mapped the transition from 3D Regulation, Deregulation, and Post-Deregulation, so my comments are flavored with that background. Next, please.

Although I'm going to hit the technology experience, I do want to highlight one item in terms of this, you know, technology is not a barrier, in my opinion, and our experience, I believe, shows that. Cost is not a barrier when measured against the value provided, and that's come up because of the -- but the last one in green modeling, I think, it is critical to get in place in California because, to implement this at scale, it won't be done absent the grid impact studies, the production cost studies, that evaluate ahead of the full-scale, real time operation, and it's going to take too many years to accumulate, in my opinion, the field experience to inform the decision makers. So a key thing is, in my opinion, plug the models that are available into the existing planning activities within the regulatory agencies and their regulated entities.

And now down back into the trenches. Next slide, please. You'll notice California is in green there, but I want to jump right at the top, there's a

California that's not green and that was the two MW -- it's actually two MW container connected at AES Huntington Beach. That was used successfully as a test pilot project, but I do also want to point out, it did go do the test and did certify as an ancillary service asset, and it was one of a very early experience that helped inform some of the what I'll call incremental market rule changes needed to broaden the access to energy storage as a participating technology.

The other California one down there, we've got four MW connected today by an investor-owned utility that still has not announced it, but it's connected to a retail distribution circuit, supporting service, a load today. And then, later this year, we will start operation of the Tehachapi demo and, there, I want to highlight that it's a grid-sized wind integration demo, and I'll just limit my comments that you don't necessarily have to fix the problem at the source or the asset, you can make the grid more resilient. And in my opinion, that ties into informing the decision makers and the policy makers on rate basing storage, you know, is there a role for storage as a T&D asset? Within California, I think that FERC has already spoken through the Western Grid Developers conditional approval and back to modeling, it was conditional based on it passing the

ISO approval, and ISO cited, in part, it did not go do their planning process, therefore they did not approve it. Once again, the models -- get it plugged into the planning process.

So our specific experience, A123 manufactures the equipment, the components, the batteries through the systems, the containers, as well as constructs, and now we're actually moving into O&M, Operation and Maintenance of these grid-connected battery systems. So AES Storage is the Owner-Operator, A123 built the equipment and supported the construction through the battery component. This system is performing frequency regulation today and it's selling into the PJM market. And FERC Order 755 compliance is a great active concrete activity that is improving the rules to allow access for, and then correct compensation based on relevant capabilities for storage. And a comment on that, A123 owns and operates two MWs of the 90 MWs we've deployed. We don't believe incentives are a long term business model. Our two key requirements are asks from the industry, or remove barriers to access, and then compensate for relevant capabilities. We believe, at today's cost, that we would see more projects deployed, and to one year earlier questions, and in support of Ali's comment, there are gains to be made just from manufacturing scale that will be reflected in the cost of technologies. Once again, no technology breaks are needed, just scale and manufacturing *will* bring down the price.

Here is an example of frequency regulation as performed at the PJM facility, and the key item here is that we can effectively map the control signal or load following. So essentially we'll respond every two to four seconds, SCADA pulse, what is the next Powerpoint being called for, but for fast, accurate, advanced energy storage, there is no other asset this accurate performing this service on the grid.

So, in answer to one of the provided questions ahead of time, can storage complement DR and natural gas to help integrate? The short answer is yes. And one example, in Chili, we do have a hybrid thermal storage system built, again, for AES Storage, where they've handed over this high frequency component of their operation to the battery. And what that does is it allows them to block load the thermal generation that is used for its more valuable service, and that's selling energy, providing energy. And I'll share here on record, their payback -- and they probably mentioned it -- is well within commercial timelines, it's not the storage paying for itself, it's the release generation selling energy, where a prior had, in this case, 12 MW of constrained capacity as an obligation for spinning reserve. And there's the 12 MW for spinning reserve. So it released the generation capacity. That is not unique to Chili, that can apply around the world and specifically to California. Next slide, please.

This slide was not provided by AES Storage, nor A123, the Grid Operator in Chili did several Press Releases. In part, included in these Press Releases were identification that this battery energy storage had the highest up time and the highest response rate of any asset on the grid. And if you hit Slide 4 until we see the red and blue highlight, please? Oh, I guess it didn't come through with the highlights. Well, that lower curve is a frequency dip below one Hertz, that upper curve with almost a rectangular shape is the battery system responding at about 20 milliseconds. And you'll see that tight v-notch right there? That is the discrete specific impact on frequency improvement based on that sudden injection of power by the battery. And what that does is, the recovery point from that point onward for all the other responding assets is improved. So what would have otherwise taken longer, or, in worse case, might not have held through and might have decayed even further, was greatly improved by having a fast acting resource. So 12 MW initially deployed, an extra

20 MW deployed by AES in part through cooperative studies with the grid operator, where the grid operation once again did the Press Release announcing these strong system benefit that they were seeing, and the receptiveness for AES to offset more of their spinning reserve with a fast response battery. Next slide, please

There we go. There's a system falling and Recovering, and there's the battery output, and that's from the grid operator's own data.

Energy storage, this isn't with a gas plant or with DR, but this is directly coupled with the wind generator, and this is Vestas' research facility in Denmark. This is a system that's been performing ramp rate control.

Now, the other item that it demonstrated has been moved once and the ISO to PJM experience that California asset, backing up a little bit, two MW at AES Huntington Beach, is now in PJM selling frequency regulation, so back to your point, Dr. Ali, these containers can be relocated. So this has been moved now, once by Vestas in this case, a test system performing ramp rate control for a wind generator, and we are the process of constructing a commercial ramp rate control battery for a 21 MW commercial IPP wind farm in Maui where it was a condition of interconnection to manage ramp rate to a specified value. Next, please.

This has come up before, a key thing is an ability to do the modeling, the new element of the battery is the issue of stated charge. Do you know that your battery is going to still remain in service, or are you going to end up topping it off and, you know, encumber the ability to absorb? Or are you going to completely deplete it? Next slide, please.

The California specific, I'll just say this is relevant to AB 32 and coastal plant shutdown, storage can provide inertia, it can be controlled to provide inertia, the concepts were demonstrated at Chino by Southern California in 1994. If deployed at large-scale, once again for the right intended outcome, with the right study supporting, Advanced Energy Storage will help mitigate or prevent future blackouts in California.

And that's it. And I look forward to your questions. Thank you.

CHAIRMAN WEISENMILLER: Thanks. What's the longest you've had one of these units operating so far?

MR. VARTANIAN: The AES Huntington Beach test was in continuous service for three years.

CHAIRMAN WEISENMILLER: Okay, and in terms of how are they holding up in terms of durability?

MR. VARTANIAN: What we're seeing, that they are on track for commercial durations of 20 years, with capacity or battery incremental additions on time frequencies of three to five years, so we're seeing success as a long term asset. The cells have longer testing and field experience, the cells that we use for the Huntington Beach unit and being used at PJM have seven years of field experience as the battery used in a hybrid bus. And a hybrid bus profile is very similar, actually, to a frequency regulation signal in terms of continuous duty of accelerating and braking. So seven years of operational experience with very -- we're predicting our declines more on the automotive application, shorter term experience in the grid, it's still supporting we can predict, and they're having fades that allow planning on, once again, 15 to 20 year project lives, with three to five-year tempo in terms of maintenance additions.

CHAIRMAN WEISENMILLER: Okay, what sort of additions do you have to do to keep that 20-year life, up to 20-year life?

MR. VARTANIAN: Depending on the intensity of utilization, it's basically partial addition of battery capacity to keep the energy duration capability up to minimum amount. For example, for frequency regulation, we're putting out 15 minutes of energy duration. So, over time, there's a need to periodically add -- it's on the order of 10 to 20 percent.

CHAIRMAN WEISENMILLER: Okay, so 10 to 20 percent, is that every five years? Every 10 years? Every 15 years?

MR. VARTANIAN: Well, once again, it depends on the intensity of utilization, but based on the field data so far and our projections, three to five year tempo --

CHAIRMAN WEISENMILLER: Okay --

MR. VARTANIAN: -- on incremental addition.

CHAIRMAN WEISENMILLER: So three to five years, 10 percent --

MR. VARTANIAN: And we are putting out those containers, actually partially filled with those additions planned for the -- let's say -- the non-pilot commercial duration type project.

CHAIRMAN WEISENMILLER: Okay, thanks.

MR. KULKARNI: Our next speaker is Arthur O'Donnell, he is with California Public Utilities Commission staff. Welcome.

MR. O'DONNELL: Thank you very much, Pramad. And thank you, Commissioners, and thanks to the audience for sticking around, your attention at this late stage in the day is much appreciated. I won't try your patience, I will go very briefly through a report on status of energy storage issues at the California Public Utilities Commission and why it's important, currently.

One of the big drivers has been enactment of legislation, AB 2514, adopted in late 2010, which directed the Public Utilities Commission to look into whether utilities ought to be ordered to procure storage. There are various components of that; non-regulated entities should also be investigating this. But, in particular, the PUC was given a deadline by October 1st, 2013, to adopt energy storage procurement target if determined to be appropriate, and that is a key to our proceeding and there are two dates by which the utilities and the load serving entities would procure under this.

Also, importantly, we were given a charge to consider a variety of possible policies to encourage cost-effective deployment of energy storage systems including, and especially, I think, a refinement of existing procurement methods. This is not a one-time only deal, every three years there should be a proceeding that builds upon previous proceedings, and I think this is a recognition by lawmakers and by policy makers that the technology is maturing and that market needs are evolving, and we're supposed to be addressing that.

The storage timeline is that there has been a lot of preliminary work, we've completed what is called

Phase 1, I will put a kudos out to the California Energy Commission for its Storage 2020 Vision Report, which was seminal in helping us understand many of the issues, along with a lot of other work, this is certainly something where we're trying to draw on the universe of understanding in order to set correct policy.

Much of last year, 2011, was spent in workshops in trying to understand certain issues like the barriers towards storage, like what kind of regulatory issues are being faced by storage providers, not just at Public Utilities Commission, but also at the Independent System Operator and the Federal Energy Regulatory Commission. This led to a staff proposal issue at the end of 2011 which laid out a course for us to follow in Phase 2. I have copies of that proposal, which was finalized at the end of March, early April. For anyone that has not seen it, it really gives you a flavor of kind of what we've addressed and where we hope to go. The next slide is way too busy to go into detail here, but essentially there are four components of our analysis, one is the regulatory framework, also to look at cost-effectiveness. I don't know that we can answer the question of cost-effectiveness for storage because there are so many different types of storage, so many different applications, which leads us to really another key component of our analysis, which is a use-based, applications-based analysis which echoes what many people have said already, is that truly the value of storage comes in how you use it, and the costs associated depends on where it is and how you use it, and all of those things needs to be understood before you can make a statement about whether there is value that exceeds the costs. And we're going to be trying to address that. But we have procurement objectives, which I mentioned and also a roadmap going forward. Next slide, please.

The Regulatory framework, aside from this storage proceeding which was opened in late 2010, there are many places where storage is now coming into proceedings as an issue at the PUC. I'll just briefly mention a few of them.

The Resource Adequacy Proceeding, Flexible capacity is coming as a foremost issue in that proceeding, and we hope to address how storage can provide some kind of flexibility and how you value that.

Long-Term Power Procurement, similarly you base your needs going forward on kind of what's going on in the system, and we're looking at 2017 and beyond as important framework base for dealing with possible new resource needs, in Southern California, particularly because of the retirement of OTC resources, and other things that have reared their heads.

Self-Generation Incentive Program. It is interesting to note that a change in that program last year allowed storage as a standalone bidding option, as well as storage in conjunction with renewable energy, mostly PV, it led to almost 150 applications for the incentive that's associated with that, and many of those are batteries with PV, but we're seeing even more configurations, and that’s an interesting development.

Demand Response Programs. It was alluded to that the PUC, of course, has a very healthy Demand Response program. In the most recent Decision in April, there was $32 million of utility budgets for Permanent Load Shifting. Much of that money will go to thermal storage, which is used for peak load shifting and we estimate that that may lead to about 49 or 50 MW of new storage technologies in operation by 2014, or shortly thereafter.

We have RPS Evaluations, you'll hear a little bit more about one of the new issues, which is a Power Purchase Agreement renegotiation between SoCal Edison and BrightSource, which adds now thermal molten salt storage to the solar power tower configuration, to make it cost-effective and dispatchable, that's a new event on the U.S. horizon and, of course, the technology has been in effect in Europe for several years.

Rate Design issues were alluded to. And this harkens back to there are many different ones, but in particular Time Of Use Rates (TOU rates) are very important for customer-side storage because, if you don't have a good enough differential between daytime and nighttime, the economics aren't there.

Finally, ISO Markets have been alluded to quite frequently in terms of Frequency Regulation.

And the FERC Rulemakings, which are leading to market changes, Order No. 755. Next slide, please.

The Summary of the Staff Proposal, very briefly, is that we're going to be looking at the priorities that are shaped by existing policy articulations and Storage to support renewable energy integration is a primary one, it was one of the primary uses that was identified by the State Legislature. There are, of course, other potential values to the public system, which is to avoid distribution system upgrades, to provide demand-side management, behind the meter, and to provide ancillary services.

Now, there's only so much that the PUC can do, and so we've taken an approach that really tries to focus on what are the most valuable uses of storage for utility generation for distribution and for customer-side, we're going to leave the ISO market to the ISO, but recognize, as has been stated in the past, that storage in terms of being cost-effective, often needs to aggregate revenue streams, and so the ability to play in both markets may be crucial for some storage technologies, going forward.

I will highlight two of the six use cases that we've focused on; one is Community Energy Storage, which you heard alluded to in Ali Nourai's presentation, to provide local service reliability and variable energy resources sited, essentially renewables integration, those are the primary benefits. What we hope to do is really lay this out in a case study approach, where we identify these particular applications with the kinds of technologies that will most likely be used to solve that problem, how they are used, what kind of operational considerations go into effect, what kind of revenue streams could be relied upon to make these technologies cost-effective, and approach it with a real world example that backs up that mirror, that kind of use, whether it's already in effect in California, is under construction, or has been used elsewhere.

I'll go quickly through the next two slides, one is the use case for Community Energy Storage, and we have a couple of examples. One is in SMUD territory, the Smart Solar in the Anatolia Neighborhood, in which batteries are being used to backup a lot of residential PV that is congregating in one particular neighborhood and they are using this to kind of smooth out the PV generation profile, and also to provide potential backup reliability. And down in San Diego Gas & Electric territory, there are also Community Energy Storage proposals that are coming into fruition now. Next slide, please.

Variable Energy Resource-Sited, you know, Community Energy Storage is one of those examples, but on a large generation side, you've already heard today about the AES Laurel Mountain project, which uses a 32 MW configuration of batteries to backup a 98 MW wind farm; that was a perfect example of two or more potential revenue streams in which it's providing frequency response to the PJM market, but also firming and ramping services that may be beneficial for the operations of that wind.

We're going to have more than six, probably eight, maybe 10 of these use cases that really flesh out all of these considerations so that we can address several questions, which is, when is storage valuable? Under what circumstances? What are the costs and benefits associated with this so that we can provide players in the market with the tools to do a cost-effectiveness testing when they come to the Commission to seek approval for projects.

Next Steps. The ALJ assigned to this case is currently writing a Proposed Decision to close out Phase 1 to formally introduce the Staff Proposal into the record and to lay out the steps for a Phase 2, which will include another scoping memo. We expect to have workshops during this summer and comments from parties on the various major issues that are going forward. These workshops will refine the Use Case Analysis and staff will then identify potentials for specified targets and develop a roadmap for long-term action, how we deal with this going forward. With that, I will close out this presentation. Thank you all so very much for your attention, and I stand ready to answer any questions.

CHAIRMAN WEISENMILLER: Thank you, Art. It's certainly good to see you again. I guess the question I have, certainly thinking back to my MRW days, where I had clients with thermal storage and the difficulty they had is a lack of predictability and retail rates on the differential between off peak and on peak. In fact, some of the facilities, at least from various stages, were just sort of parked because the economics wasn't there --

MR. O'DONNELL: Right. And --

CHAIRMAN WEISENMILLER: -- on an operating cost basis.

MR. O'DONNELL: -- rates continue to be an issue, you know, at least two of the utilities are looking at reconfiguring their Time Of Use rates, maybe better, maybe worse, I mean, we're in a situation where the overall resources are not arguing well because we are in a capacity overage in many parts of the state, at least currently. We don't know if that's going to last. The Time Of Use rates also play into the payment stream for something like thermal storage and use with solar power because the differential between the daytime or the off-peak rate may not be enough to really incentivize that large molten storage tank, but Udi can talk about that.

CHAIRMAN WEISENMILLER: Yeah, no, it is a combination of the differential and the longevity of the differential, you know, obviously the last thing people need is to look at the numbers, it pencils out, and build something and discover that somehow the rate design has changed in a way that it no longer makes any sense.

MR. O'DONNELL: Right. And at least with regard to thermal energy storage, I know that one of the major purveyors of thermal storage, ICE Technologies, is really looking to a different ownership model, they're looking to utilities to be the owners of these facilities; certainly they have a contract with Southern California Municipal Utilities to install about 52 or 53 MW of ice storage, that would change their economics greatly.

CHAIRMAN WEISENMILLER: Right, no, that certainly deals with the issue if you're trying to do project financing and you're trying to convince the banks as to the stability of the rate design; you know, good luck.

MR. KULKARNI: Thank you, Arthur. We have the last speaker of the last panel of the last workshop for this series. But nonetheless, I'm sure you know what Dr. Udi Helman has got to say, some new and exciting information. He is the Director of Economics and Pricing Analysis at BrightSource. So, Dr. Udi Helman.

COMMISSIONER PETERMAN: Udi, we're looking for you to end on a bright note!

DR. HELMAN: Well, thank you. And thank you very much for the invitation to speak. Just, I could answer the last question, the TOD rate issue and PPAs, when you come to a partially dispatchable plant like this, it does have to be addressed in the contract terms, otherwise the incentives really aren't right to get the full value out of the plant. So our Edison contracts have provisions to allow them for that dispatch capability, regardless of what they want to do with the energy.

So with that, thanks again. BrightSource, as you know, is one of the leading developers of solar thermal power plants and we're very excited about the Ivanpah plant will be coming on-line early next year and that, as was mentioned earlier, we have these three other plants, 200 MW plants with two hours of thermal storage, each. So that's a fairly significant contribution to the dispatchability needed on the California power system. But we're not the only company in this sector, the technology also, as Arthur mentioned, has been deployed in Spain and the other companies, Abengoa and Solar Reserve, that have plants under construction with thermal storage.

I think what is new from our point of view is the emphasis that we've put on dispatchability, that's the new element that wasn't really there in the development of the Spanish plants, but we know what the California power system looks like and we know what the utilities are looking for, and they're not necessarily looking at this point for a base loaded solar power plant, but they're looking for something that's flexible and can provide as much value as possible.

If I go to my first slide, Todd Strauss would have gave about as good an overview of the interaction between markets planning procurement, etc., as one could ask for in a short period of time, and we have faced that same problem in part because we're an RPS power plant, and we're really selling RPS energy, we're actually not really (quote) "selling flexibility," unlike other types of storage, that is just simply an attribute of our power plants and that wasn't part of the RPS valuation process until -- it's beginning to be at this point, in part due to our influence. But RPS energy wasn't originally valued for its flexibility and I think we are the first contract -- our contracts with Edison, I think, were the first ones to move in that direction.

But that left us in a bit of a quandary, alluding to what Todd said, the lack of coordination between RPS program integration analyses, long term procurement, and resource adequacy, and that's what my first slide gets to. I know this session is on integration, but these plans, the CSP plans with thermal storage, both reduce the integration needs on the system and also provide integration services, so they have those dual features to them, and they also are more flexible as capacity resources, so they have a need to be valued across a range of services, and the understanding of what that value is, is becoming more concrete but is still being worked on.

Let me make one other very quick point about thermal energy storage. And that is that, unlike these other types of storage that we've been discussing, it's not charged from the grid, it's charged from the solar field, so it doesn't present quite some of the analytical challenges that we face, for example, using production simulation models, which classically have trouble operating storage on the same basis as you see in real markets because they don't generate the same price differentials, the models typically don't generate those differentials as much as actual markets. There are all kinds of issues in modeling grid-based storage, but ours is not a grid-based storage plant, so it's actually easier in some ways to analyze; you just have to understand what your stock of charged energy is and then run the model to see what you do with it later in the day.

And that gets to my next slide, which is that what you do with it, because once you know what that charge is, and let's just focus on a clear day just for the sake of simplicity, then you have a pretty good sense of what your production is the next day, a lot of your forecast air issues are taken care of and even if there is some differential, if you have thermal storage you can firm your own production the next day. You could use thermal storage also to smooth out production on cloudy days, depending on how much sunlight you have to charge a thermal storage system. Well, then I think something that is also pretty important, and I was glad to hear Todd Strauss bring this up, is that a big impact on the system of the future is these massive ramps that were discussed earlier by Mark.

So the thermal storage, another misunderstanding about CSP and thermal storage is that you can use it in the late afternoon or in the midnight, or you can shift it to the next morning, so you could, if it was desired by the system, you could use it to affect the morning ramp of solar, you could slow that ramp rate down, it's actually a net load ramp rate down, as you'll see on my next slide. And then you could also use it to slow the rate of the late afternoon net load ramp up, and those are two periods of time that will have the most impact on the power system in the future.

And then, another integration value is, if you understand what you're getting out of these plants better, then you possibly could offset the need for new integration resources such as additional peakers, or even other types of storage. So we do have some simulations underway to look at that question.

To illustrate what I'm talking about, we created the next slide, actually the next two slides, which have their best effect if they're flipped back and forth quickly, so if you go back and forth once or twice, you can see the net load ramp change in the afternoon on the green slide. So the first slide is just a snapshot of a particular day from the PUC CAISO Simulations that were used for the Integration Study, so we just took their input data, which is public, and that has a one hour net load ramp in the late afternoon of almost 6,800 MW, that's 8,000 MW of ramp up by dispatchable resources in that one hour. To get that ramp up, the ISO would have to have that much head room on the natural gas-powered fleet, so obviously you need a lot of gas units at below their P Max level to be able to hit that ramp in one hour. So there's going to be a cost impact, an emissions impact in that hour.

And then the next slide, just for illustrative purposes, it is not intended to be a policy recommendation or anything to use in any such context, we just took one of our two-hour production profiles where the energy is used right in the late afternoon, and imagined that there were 2,000 MW of plants with that capability in the system, and that's what causes that shift in the net load ramp in the late afternoon, which comes down to about 4,500 MW of a net load ramp in that period. It also causes some other changes in the profile there, as you can see in the figure, and that's why we put the not optimized caveat on the top, this isn't necessarily how you'd operate these plants, it's just one way that you could do it; you might want to move that energy further out into the day if it has more value, like further out, you know, a few more hours out into the evenings. So it's not an optimized profile, it was just a simple sort of snapshot to get to illustrate the concept.

But on the next slide, we did take some of the data out of the CAISO integration work and you see that the late afternoon is -- in the sort of mid-morning solar ramp-up period in the late afternoon, that is where a lot of the additional impacts will be, so that result is in the data, it's been in the data for a long time, this is the load following result, but it's the same kind of profile for the regulation result. So what that means is that, with an investment in plants that can essentially take care of that interval, we can then focus the rest of our investments on other types of storage that need to meet, let's say, the ongoing additional regulation requirement, that there is more static over the day.

And the next slide just points out that, once the utility owns a plant like this, they can decide what to do with it, so if it's a day when the net load ramp isn't that extreme, but it wants to back down some gas units and use the plants to provide spinning reserves, for example, it could do that. So it could put solar plants on minimum generation level and hold them there for a few hours to provide spinning reserve, which is kind of an interesting proposition. And, in fact, our three plants with Edison could provide almost all of Edison's spinning reserve needs, just those three 200 MW plants, for the hours that they're available. So that's another possible us of the plant.

In the interest of time, I'll skip the next slide, which was about the shifting net load peak issue, and just say that we've made a lot of headway in the past year, this value of CSP with thermal storage has become much more front and center in the policy environment, and we'll get more clarity over the next few months, not only the deployment of some of these plants, but also the CAISO Integration Studies have provided a lot of data and will continue to.

NREL has a study underway using production models that will deliver results shortly. LBL has just put out a study that values CSP with thermal storage alongside other technologies. California Energy

Commission has a study that is being kicked off soon and may have a workshop on the topic. And EPRI is doing some analysis for some of its clients on this topic. So, in just the past year and a half, there's been this enormous mushrooming of studies and analysis going on, so I think we feel a lot more confident in the analytical foundations of this technology.

And then, finally, the PUC is moving ahead with introducing integration costs, ancillary service value, into the RPS procurement. So the threads are being tied together, but as Todd alluded to, there will be a huge amount of work to be done this coming year. And that concludes my comments. Thank you.

COMMISSIONER PETERMAN: Thank you very much. I think you've probably heard me say a couple times from the dais, I'm very pleased that the PUC is looking at integration costs as part of their procurement process, I think it will be important to look at those all in cost.

Just a comment and then a question, and then I'm sure the Chair might have a question or two. In terms of the ability for solar thermal and the storage associated to provide spinning reserves, I guess one question I would have is, looking at where solar thermal is currently being concentrated in the state, because of where the plants are located, whether there would be a concern with the transmission line availability in terms of providing all of the spinning reserves in that Mojave region, for example, and so that's just more an observation, and perhaps there will be more opportunity to do solar thermal elsewhere. And then a question I had for you is that, you mentioned on some of your existing plants you have about two hours of storage, could you just speak to why two hours? You know, what's the capability for more, is it just that you need to be incentivized for it? Is there some sweet spot in terms of storage size for solar thermal plants?

DR. HELMAN: So on the first question, you know, yes, you'd have to determine that the transmission capacity is available. And you might find that, in the evening there's more available because the solar is off the system, so you know, it might be made available, just that -- well, I think one of the interesting things about the solar thermal storage is that it's charged over the day, and if you look at what the simulation results look like over the day, the middle of the day isn't that -- doesn't look that complicated. And then you're charging this additional dispatchable capability that becomes available right as the big impacts begin, which is solar comes off the system and wind starts to pick up again. So it's a nice coincidence in terms of value, and you get a lot of value out of just two hours of it, just for that reason.

The two hours was an election by Southern California Edison, so it did not come from our analysis, so, you know, I assume that's on the basis of their internal analysis.

MR. O'DONNELL: If I could add that there is at least one plant operating in Spain that purports to be a 24-hour resource, I mean, and the technology of most storage is that it doesn't lose much heat over the course of a week, so you could essentially hold it that long, but you wouldn't be getting nearly as much of the economic value as if you were using it two hours every day.

COMMISSIONER PETERMAN: Thank you. I mean, just in terms of the cost with the molten storage, I mean, are there any economies of scale for size, and larger, is it that the costs will be incremental based on the capacity?

MR. HELMAN: I think it depends, there are three different technologies out there and I think we should probably reserve the detailed technology discussion for that other workshop that I think --

COMMISSIONER PETERMAN: But we're here already.

MR. HELMAN: -- you're planning to have. Well, I can't really speak to those other technologies, so I would hate to assert anything about them. I think from our point of view, I don't think I'm going to say anything either because of the commercial implications of the contracts that we have out there and the election made by Southern California Edison. So it's possible that they could be some value. I think one interesting thing is that a lot of the analyses that we've done to date have sort of ended in 2020, and that's -- that's not entirely true; I think some of the utility simulations have gone out to 2030 and beyond. So, I think there's a case to be made possibly that two or three hours of the solar thermal storage is where you start to see declining net benefits -- we've done some of those simulations. If you look historically, at historical load shapes, and you look at how much wind might be on the system in the future depressing overnight prices and so forth. So I think that there is an economic case to be made for two or three hours of storage, in that range. Whether you want to think about the system design beyond that, and for some of the changes that may come after 2020, that's a different story, and we haven't really done that kind of analysis in depth.

COMMISSIONER PETERMAN: Thank you. Well, my question was more basic, just in terms of cost and not value, but thank you for commenting on perhaps a difference of value, as well.

DR. HELMAN: There is -- in the current design of our plants, there is a cost curve that does start to increase again as you get beyond a certain size on the thermal storage capacity, so it's not a simple question of a continuing declining cost curve as you add more storage. It depends on the design of the plant.

COMMISSIONER PETERMAN: That's helpful, thank you.

CHAIRMAN WEISENMILLER: I guess the other way to try to get at is, Science Magazine in the last six months had a special section on storage and got a lot into the Spanish experience, you know, and the tradeoffs there. I guess the question I was going to ask, just trying to connect the two of you, Arthur, in terms of your storage work, does that connect over to the PUC's procurement review group types of stuff?

MR. O'DONNELL: On an informal basis; many people were looking to this proceeding to be an omnibus, be all end all, and we really just are not set up to that. But I am committed, and it's part of my charge to break down the silos within the Commission, and to that end what we're doing is, internally within the Energy Division, the Analysts that are charged with the various things like the Long Term Procurement case, their RA case, are getting together and talking about these issues, and helping each other understand how they play out. Now, that's at staff level, it's also to go higher up within the hierarchy and let the Program Managers and the head of the division, and the ALJs that are dealing with this, understand how all these things interplay. And that's ongoing work. But, no, we're not going to be telling the LTPP case what to do, we are going to try and inform things like the resource adequacy case about how to value storage within their construct, to look at LTPP and identify where there are maybe unstated barriers to the use of storage, whether it's in the structure of the utility RFOs that are used to meet those needs, right, which do not discriminate overtly against storage, but were configured in an era when gas-fired peakers were the answer to everything. So, kind of like they might have built-in barriers.

CHAIRMAN WEISENMILLER: Yeah, I mean, certainly I've heard the hypothesis that, in the valuation of thermal plants with storage versus, say, PV, or whatever, that the storage characteristics are not being appropriately valued. And that's normally coming from the solar thermal plants that aren't winning the RFOs, but there may be some truth to that.

MR. O'DONNELL: Well, I think overall we're seeing an evolution in the markets because many of the benefits that can be associated with storage have not been monetized in the past, we don't know how to do it properly. And, as you know, in setting administrative kinds of costs, you're essentially doing informed guesswork. We want to try and avoid that, lean towards markets, understand where markets are going, and use the benefit of those markets to help inform any kind of analysis.

CHAIRMAN WEISENMILLER: My impression was the Solar Reserve Project, that its PPA was pending before the PUC, has that been approved, or not approved?

MR. O'DONNELL: I'm sorry, which?

CHAIRMAN WEISENMILLER: The Solar Reserve, that's the one with the molten salts, so I'm assuming its cost structure would be greater than, say, Udi's, but presumably also has the ability to shift around production more.

MR. O'DONNELL: I think it's in process, I don't know, a whole bunch of PPAs were just approved and I don't know if they were part of that package.

CHAIRMAN WEISENMILLER: Okay. Thanks.

COMMISSIONER PETERMAN: Thank you. This has been a very informative panel. Thank you for your detail and attention. Pramad, I'm going to suggest that we see if there's any public comment right now, but if the panelists are able to stay with us until 5:00, if not, let us know, it would be great to hear if you have any final comments or recommendations for us that you want to let us know now, and also I encourage you to submit comments to the record.

MS. KOROSEC: We do have one speaker who has a time constraint that I'd like to let go first.

COMMISSIONER PETERMAN: Please.

MS. KOROSEC: Bill Keese.

COMMISSIONER PETERMAN: Welcome.

MR. KEESE: Commissioner. Bill Keese on behalf of Eagle Crest Energy. We're developing a 1,300 MW pump storage project in Southern California, 30 miles east of Indio, 10 miles off Palos Verdes, Devers, generally the reason there haven't been projects for a couple of decades in California is because of location. Well, we're in an abandoned mine pit, we're FERC jurisdictional, we've completed all the steps at FERC, we expect to get our license in the third quarter of this year. We're a member of CAREBS, Coalition to Advance Renewable Energy for Bulk Storage. I speak for Eagle Crest only.

We've heard much today about what some have called balancing of grid operations. We've heard response time, we've heard ramp rate, we've heard quantity, I'd like -- we're not your mother's bulk storage, let me refer you to what we are -- our quantity is 1,300 MW of supply or demand, we can swing in seven and a half minutes from 1,300 MW of supply to 1,300 MW of demand. Our response time is instantaneous. Our ramp rate is instantaneous. Our ramp rate is 10 to 20 MW per second. Our duration is 15 plus hours. Our cost, if you want to compare us to generation, is about $1,500 per MW. Our efficiency rate, I'll add, in addition to your earlier questions, is about 82 percent.

Most of the benefits of balancing are not compensated today as speaker after speaker has emphasized. Those benefits accrue across the board to all ratepayers. And what we need is a regulatory framework that allows monetization of those benefits in a transparent process that allows natural gas generation, Demand Response, and all forms of storage to compete, to do this balancing. Thank you.

CHAIRMAN WEISENMILLER: Thank you.

COMMISSIONER PETERMAN: Thank you.

CHAIRMAN WEISENMILLER: I'm assuming you would need a PPA to be built.

MR. KEESE: You know, we don't -- we fall in a niche much like everybody else does, that there is no way to monetize this. Do we need a PPA for generation? We need a PPA because we can fly 1,300 MW of black start, because we can do all the ramping anyone needs, we can do the voltage, but we can do all of it. So the question is, what kind of a PPA do we need? Do we fit in the ISO queue as generation? Well, that's the only queue there is, but we're not just generation. So we're going to have to figure out as soon as we get our FERC license and can talk seriously with different parties, what our business model is going to be.

CHAIRMAN WEISENMILLER: Okay, and I'm just assuming that you're not going to try to do the merchant pump storage.

MR. KEESE: We are not going to be a merchant pump storage facility. But if you're sitting there with 1,300 MW of supply that can go into the marketplace, and you're not generating, you're not getting any compensation. So we have to figure out what it is, the values of it, just as everybody else in storage is talking about the values that they bring, we're going to have to figure out what they are and then get some kind of a -- a PPA perhaps. Now, I will tell you that we hope to get our permit in the third quarter because that will allow us to come on-line late 2017 or 2018. We're already looking at what everybody has said in these different proceedings, is the time when we're going to have a crunch because of once-through cooling, because of retirements. We need to move fast and hopefully in five or six years we'll have something for you.

COMMISSIONER PETERMAN: Thank you. I was going to ask you when you expected to be on-line and I think your comment about 2017, 2018, harkens back to a previous workshop we had on storage about some of the lag time and needing to think seriously if we're looking for stuff in the next seven years --

MR. KEESE: Yeah, we need to do some final engineering and, when you have a plant this size, you have a tunnel that is 31 feet in diameter, I guess about the size of this room, that's going to run two miles across and 1,100 feet ahead.

COMMISSIONER PETERMAN: Thank you very much.

MR. KEESE: Thanks.

MR. KUBASSEK: Good afternoon, Commissioners, staff, and fellow workshop participants. I'm Justin Kubassek from Southern California Edison and I coordinate SCE's involvement in the IEPR process, and I appreciate the opportunity to provide some comments.

I just want to start out by expressing our support for this workshop and especially the Commission's efforts to try and understand the costs associated with different types of renewable generation, as well as looking to develop strategies to minimize those costs as we work to achieve the state's energy goals.

I think the questions posed by the Energy Commission for this workshop were very insightful and finding answers to them will certainly help us guide the state's policies and policy direction. What I wanted to say in public comments was actually kind of touched on briefly, so I just want to use this as an opportunity to emphasize a point that Edison finds to be important. A number of panelists and you, Commissioners, discussed the need for making sure that we have kind of a market and potentially a forward looking market that allows many different solutions and technologies to compete to meet the integration requirements of the future electricity grid. I just want to emphasize that designing policies and markets that assign cost to the entities that cause them will support efficient development of mitigating technologies and solutions. As has been mentioned before, if these costs continue to be socialized across all electricity customers, there's no value stream there to be captured. SCE looks forward to submitting additional written comments. Thank you.

CHAIRMAN WEISENMILLER: Thank you.

COMMISSIONER PETERMAN: Thank you, Justin, it's nice to put a face to one of the anonymous, but helpful authors to your comments. And I will say this, just so you know, sometimes people ask that, all the comments that are filed, and particularly our utility comments, are reviewed and considered, so even if not everything is included in the final IEPR, your comments were read and appreciated and considered, so thank you for that.

MR. KUBASSEK: I appreciate it.

CHAIRMAN WEISENMILLER: I wanted to also just follow-up on a question I had asked Todd about either capacity markets, or -- anyway, what do we need to do to get to a multi-year RA, or capacity markets, or whatever?

MR. KUBASSEK: You know, I will have to defer, but I'll make sure that we address that in our comments.

CHAIRMAN WEISENMILLER: Oh, that would be good. Thank you.

COMMISSIONER PETERMAN: It would be great if all the investor-owned utilities and utilities that are listening can answer that question.

MS. KOROSEC: We do have one caller on the phone, Mr. Mehta again, your line is open.

MR. MEHTA: Thank you. I patiently learned a lot of things today from various presenters. One interesting concept that I want to propose to all of you is a proposal that has been linked currently in Europe and Canada, and is an integration of a 2 MW (indiscernible) in the form of hydrogen and then which then can be used for many applications, including (indiscernible) various applications. And I believe -- I consider it a game changer when it happens because it really integrates in a really wide scale, many large energy storage potential, multi hundred megawatt and long duration for the entire system, so that the community can benefit from utilizing this resource. And there is a demonstration plan being financed in Canada and in Germany to demonstrate this concept. So I am putting this in front of you and I would be happy to talk to any interested party in the near future.

CHAIRMAN WEISENMILLER: Okay, well, thank you. I believe we heard you the first time, but certainly if you could submit stuff in writing, that would be great.

MS. KOROSEC: We have one more -- sorry, one more just popped in. Steve Davis. Steve, your line is open. Steve, are you on the line? Okay, I think your line is open now, try again.

MR. DAVIS: Okay, thank you. Yeah, this is Steve Davis. I'm with KnGrid. We recently participated in a market simulation for the CAISO on the Regulation Energy Management Market Mechanism, which is due for release, I believe, some time maybe this year. And one of the things that we have not yet seen announced by the ISO, which we think is pretty important, is a change or relaxation in the Revenue Quality Metering Requirement, which could create a pretty large barrier for the storage resources that could participate in that market mechanism. So that's more of a comment, I guess, as well as a question for any of the CAISO representatives that are there today.

CHAIRMAN WEISENMILLER: Actually, this is the only panel today without an ISO participant, so I'm not sure if we have anyone in the room for the ISO, but certainly would encourage written comments from you on this, maybe we'll get a response.

COMMISSIONER PETERMAN: Yeah, and I'll just -- hi, this is -- well, thank you, first of all, for listening to the workshop today, we appreciate your engagement. Just in terms of the topic of Revenue Quality Meters, we've been having to deal with this issue and we're thinking about this at the Energy Commission in terms of some of our renewable programs, and ultimately we want to make sure that we're accurately measuring the renewable energy that we are supporting and compensating for, and so I think that's the challenge that we are facing here, that we know there's an additional cost, but ultimately, if these are resources that will be online for a number of years, we want to make sure that we're actually measuring the generation and encouraging investment in meters that are accurate from the get go because it becomes more costly and cumbersome to do it so after the fact. But that's just the perspective I’m bringing here from looking at our distributed generation programs and it's a question we can raise again to the ISO, as well. So, thank you for your comment.

MR. DAVIS: Yeah, the question, though, it's currently approximately $5,000 for a Revenue Quality Meter versus a Smart Meter, which from what I understand, is capable of providing that level of obtainable accuracy for the cost.

COMMISSIONER PETERMAN: Thank you.

MR. DAVIS: Thank you.

COMMISSIONER PETERMAN: Any other comments here in the room?

MR. KULKARNI: I have a quick question, the last question, I think --

COMMISSIONER PETERMAN: Please.

MR. KULKARNI: The question is, you know, those who are familiar with the WDAT, which is a wholesale distribution access tariff on the distribution side, there are long queues for getting interconnected; the question is, can the use of storage on the distribution side reduce either the cost of interconnection, or the time that is required for interconnection? Or is this too kind of general a question because there is so much diversity in the issues involved? Anybody who is on the distribution side? Are there examples where the use of storage has reduced interconnection costs or time?

DR. NOURAI: I don't think -- this is Ali Nourai, KEMA. I don’t think it has a direct impact. It's more of being more acceptable to the utility or not, but as far as the time and cost of interconnection, I don't see that directly.

MR. KULKARNI: Thank you. And I would like to thank the panel for very insightful comments and, more importantly, I look at the time, so that is equally what I'm applauding for. So thanks again.

COMMISSIONER PETERMAN: Would you like to -- I think we have an extra minute here -- and give the panelists the opportunity to give any final comments?

MR. KULKARNI: I'm sorry.

COMMISSIONER PETERMAN: I know, normally we're rushing you, but somehow, miraculously, we've made up time, so thank you for that. I think this panel is partly responsible for that, so we'll give them a couple extra minutes.

MR. EYER: I'll just make one comment down in the weeds. We saw allusion to the Time Of Use, that’s an energy tariff, the demand charge tariffs are also really important, particularly important for storage.

MR. KULKARNI: Udi, do you have any comments?

DR. HELMAN: No, thanks. I think it's been a great panel and the discussions earlier today were also really, I think, well encompassing of many of the issues. So --

COMMISSIONER PETERMAN: Well, great. Thank you. I mean, one of the benefits of these workshops, hopefully, is that panelists are able to participate more than their panel because we want to encourage the dialogue amongst regulators and industry and various stakeholders, and I think that's one of the best outcomes of the workshops we have.

So, Pramad, thank you very much for your moderation of this panel.

It has been a very full day. It's been a full series of seven workshops. Indeed, we're very ambitious, we came up with five high level strategies in the 2011 IEPR, and then have conducted seven workshops to try to flesh out these strategies.

Just so everyone knows, next steps will be developing a list of detailed recommendations. The idea with this 2012 IEPR is that we want to have something relatively short, that you can take away bulleted, we've done a lot of the discussion in writing about the challenges in the 2011 IEPR, and this one will say, now, where do we go from here?

We're looking for recommendations that are necessary to reach the 2020 goals, as well as position us for higher goals going forward. We'll be putting something out in a draft document and asking for responses. We'll also be holding an IEPR workshop where we will review this document, as well as some of the other products as a part of this year's IEPR.

You can find information on all seven workshops online, the transcripts there are also there, I encourage you to review. Although this is the last of the workshops for the Renewable Strategic Plan, I would encourage you, if you're interested in all things energy, to check out our next workshop, it may be the final IEPR workshop -- is that possible?

MS. KOROSEC: Yes, so far, yeah.

COMMISSIONER PETERMAN: So far. Before we come out with a comprehensive document. And that's on June 22nd, it's going to be on infrastructure needs and challenges, and will be in L.A., downtown L.A., because we'll be focusing primarily on South Coast and San

Onofre, and the Summer Of issues. And we'll have a diverse representation from various stakeholders, and it will be one not to be missed.

So with that, let me first thank Chair Weisenmiller, who has been a great asset to have here on the dais, as I do my leading on my first IEPR, and appreciate working with him. Also thank you to my fellow Commissioners who have also participated on the dais at different points in time. Thank you today, in particular, to Commissioner Simon and the Public Utilities Commission for participating and for Commissioners Florio and Sandoval for participating in previous workshops, as well. Thanks also -- you get all the thanks because it's the last workshop -- Suzanne Korosec, who is IEPR Team Lead, who has been phenomenal, and her staff, as well as Heather Raitt, who has been Project Manager on the Renewable Strategic Plan; they are responsible for all the successes and me for all the problems.

So with that, let me turn to the Chair for any final comments.

CHAIRMAN WEISENMILLER: Yes, again, I certainly would like to thank all the participants in this and certainly thank you for your leadership on this, you know, I think in terms of taking -- where we got to last year, but now trying to have a pretty public process, has been, as you indicated, we've had a pretty good participation from the PUC, and I know talking to Mark Ferron, he's listened to a number of our workshops, so I think in terms of PUC participation, even when they weren't here, they have been certainly actively involved.

Again, I appreciated everyone's activity. I found this one to be an interesting one because, again, I think all of us, and particularly as a scientist, all of us like the technologies and the various tradeoffs, particularly some of the innovative technologies, but at the end of the day, it comes back to what are the values and I think we were trying to frame this as a way of comparing some of our technology choices to provide some of those values for us, or some of the services. So, again, I think in terms of moving forward, this is helpful, you know, and certainly appreciate people's comments. I think all of us look forward to the next step as we get your comments in and as our team goes through and tries to synthesize the record we've developed. It's always scary for a prospective -- I always look back, I think it was the first IEPR that -- the 2005 one -- was like 66 days of hearings or something, so…. I think we had 35 last year, so as we struggle with whatever day eight here is like, oh, my

God. Fortunately it's not a full blown IEPR, and fortunately we're not trying to break any of those records.

COMMISSIONER PETERMAN: Indeed. And I will say that, also with your comments, I mean, you can make them as lengthy as you like; however, length does not mean that they are considered more highly, so feel free also to just bullet point your recommendations and not justify them, I think we've had a good record developed here. And, really, we're just interested in hearing what you think the State should do. This is a unique opportunity and we want to reflect what stakeholders are thinking. So thank you again. And with that, we are adjourned.

(Adjourned at 5:05 p.m.)