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PUBLIC MEETING

on the

2018 Integrated Energy Policy Report (IEPR) Update

Joint Agency Workshop

on Energy Reliability in Southern California

held at the

South Coast Air Quality Management District
Auditorium
21865 Copley Drive
Diamond Bar, California 91765

Tuesday, May 8, 2018

Reported by:
Marlee Nelson

APPEARANCES

State and Local Agency Workshop Leaders

Chair Robert B. Weisenmiller, California Energy Commission
Commissioner Andrew McAllister, California Energy Commission
Commissioner Liane M. Randolph, California Public Utilities Commission
Commissioner Clifford Rechtschaffen, California Public Utilities Commission
Mark Rothleder, California Independent System Operator
Reiko Kerr, Los Angeles Department of Water and Power
Alan Walker, Division of Oil, Gas & Geothermal Resources
Laki Tisopulos, South Coast Air Quality Management District

Also present

Heather Raitt, Integrated Energy Policy Report Program Manager
Drew Bohan, Executive Director, California Energy Commission
Neil Millar, California Independent System Operator
Garry Chinn, Southern California Edison
John Jontry, San Diego Gas & Electric
John Zoida, Southern California Edison
David H. Thai, San Diego Gas & Electric
Jason Rondou, Los Angeles Department of Water & Power
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Dennis Peters, California Independent System Operator
Chris Lynn, Los Angeles Department of Power & Water
Catherine Elder, Aspen Environmental Group
Rodger Schwecke, Southern California Gas Company
Dan Rendler, Southern California Gas Company

Public Commenters

Issam Najm, Porter Ranch Neighborhood Council
Jane Long, California Council on Science and Technology
Dave Weber, Gill Ranch Storage, LLC
Janet Fowler, Grenada Hills resident
Dave Ashuckian, California Energy Commission
Joe Crecco, Middle River Power
Andrew Krowne

I N D E X

P R O C E E D I N G S

MAY 8, 2018 10:01 A.m.

MS. RAITT: Welcome to today's Joint Agency Workshop on Energy Reliability in Southern California, taking place in the South Coast Air Quality Management District Office Auditorium in Diamond Bar.

I'm Heather Raitt, the Program Manager for the IEPR, and I will quickly go over some housekeeping items. Restrooms are down the hallway across from the auditorium entrance. And please go ahead and silence your phones.

Also, if there is an emergency, we can either do a shelter-in-place or evacuate the building. And if we need to evacuate the building, please just go out through the back auditorium doors. And if it's a shelter-in-place, such as in the event of an earthquake, please drop and cover your head and hold onto the chair.

We do have a very full agenda so I would like to remind our presenters to stay within your allotted times. Copies of the presentations and the workshop materials are at the tables at the entrance to this building and they have all been posted on our Energy Commission's website. And if you haven't already, please do sign in on the sign-in sheet at the front tables.

We will have an opportunity for public comment at the end of the day. For those who are in the auditorium, if you could fill out a blue card at the tables. We have our Public Advisor there and she can help you with that, and we'll take comments at the end of the day. And we'll just have people come to the center podium.

For our WebEx participants -- oh, I should have mentioned that we are being broadcast over our WebEx Conferencing system, so we are being recorded. And we also will have a written transcript available. The audio recording will be available in about a week and the written transcript in about a month. And for folks on WebEx, you can just raise your hand to tell our WebEx Coordinator that you'd like to make a comment at the end of the day. And at the end we'll also open up the phone lines for folks who have phoned in. And we will limit comments to three minutes per person.

We also welcome written comments and those are due on May 22nd, and the notice gives all the information on how to submit written comments.

And so with that I will turn it over to our Commissioners. Thank you.

CEC CHAIR WEISENMILLER: Good morning. I'm Chair Weisenmiller. I'm Chair of the California Energy Commission. Welcome to today's IEPR event. This is a joint event. I'm going to take a minute to let everyone introduce themselves after I give a few comments. Also Commissioner Randolph will provide a few, but anyway.

As you can tell from today's notice, we're focused on reliability today, and reliability both of the power and the gas system. Obviously, the gas system fuels the power system, so these are interrelated issues. It started a long time ago when San Onofre went out and we were trying to figure out how to maintain reliability in Southern California. I think we're almost at the end of that phase of our focus, although again I think last year we were a little surprised to discover there had been some bumps in the road, so it's good to see where we stand on that. And at the same time certainly we had a historic leak at Aliso Canyon. That's going through a series of questions to work through what that means or how to work around that.

And, as we talk today, obviously the gas system is a combination of pipelines and storage, and there's been more concerns lately on the pipeline side of stuff.

Ms. Randolph.

CPUC COMMISSIONER RANDOLPH: Thank you, Chairman Weisenmiller.

I just want to thank staff for pulling this discussion together. This is an important topic. The technical assessment for summer reliability indicates that we are going to be having some reliability challenges that we're going to really need to take seriously and manage carefully. And, to that end, I am interested in hearing from staff, you know the details about the assessment and the potential issues that we have.

We have implemented a lot of mitigation measures that have been very effective. I am a little concerned we have already grabbed all the low-hanging fruit and the other mitigation measures are going to be somewhat challenging. So I'm going to want to hear from the utility about their outages and how those are affecting the system and how those can be managed.

And then, lastly and most importantly, I want to make sure we all understand that this is a discussion about the short term, the here and now. The longer-term discussion about the viability of Aliso Canyon is something that will happen in another setting, but right now we need to be focused on what steps we need to take to ensure reliability in the summer and to make sure we're examining what effects those steps have on winter reliability, because we can't lose sight of that. So I look forward to a fruitful discussion today. Thank you.

CEC CHAIR WEISENMILLER: Great. Why don't we go through the podium, and introduce yourself.

MR. TISOPULOS: Laki Tisopulos, Deputy Executive Officer with the South Coast Air Quality Management District.

MR. ROTHLEDER: Mark Rothleder, Vice President, Market Quality Renewable Integration, at California Independent System Operator.

CEC COMMISSIONER MCALLISTER: Andrew McAllister, Commissioner at the California Energy Commission.

MS. KERR: Reiko Kerr, Senior Assistant General Manager of the Power System at Los Angeles Department of Water and Power.

MR. WALKER: I'm Alan Walker, Supervising Petroleum Engineer at the Division of Oil and Gas in Sacramento.

CEC CHAIR WEISENMILLER: And we also have Commissioner

Rechtschaffen from the PUC who will be joining us a little late. So we have a pretty full dais representing all the various agencies and certainly appreciate everyone's involvement.

Let's start with staff presentation.

MR. BOHAN: Great. Good morning. My name is Drew Bohan. I am the Executive Director of the California Energy Commission. And this panel, I'll let my colleagues introduce themselves, but this panel is going to touch on a number of issues associated with reliability in Southern California as a consequence of the San Onofre Nuclear Generating Station going offline and our once-through cooling phase-outs.

You will hear from the folks that are listed on your agenda. I will start with a brief overview and really I think a good news piece, a success story, with regards to once-through cooling.

So as you all at the dais know, once-through cooling is the process whereby coastal powerplants intake ocean water and they use that to cool the turbines. And this has been a process that has been going on for quite some time, but it does cause significant harm to marine life. As a result, in 2010, the State Water Resources Control Board adopted a policy to phase out once-through cooling at all the coastal plants in California. And, in doing so, they also created an advisory body called the SACCWIS, which is a long acronym that stands for the State Advisory Committee on Cooling Water Intake Structures. If you look up on the screen, those are the state agencies that make up the SACCWIS and provide advice to the State

Water Board. And what we look at and what we have been looking at over the years is potential threats to reliability as a consequence of these coastal power plants going offline.

SACCWIS does a report every year about this time to the State Water Board. And what I'm going to do is give you a little bit of an overview of the report that was provided very recently last month to them. So I'll work the slides here. Great.

So the report was completed on March 5th and adopted by the SACCWIS this year and it was presented on April 17th to the State Water Board. The report's main conclusion was that we don't need to make any policy changes. The power plants that we've got that have come off are no longer using once-through cooling, and I want to go through each of those very briefly, and there doesn't need to be a change to the compliance schedule for those plants that are still operating but that have dates of retirement from once-through cooling in the future.

The agencies are all continuing to work together to keep a close eye on this. And you're going to hear a little later from Mr. Millar from the ISO who is going to talk about an upcoming change that we may need to make to that. But as of April and as of our report, things are looking very good.

I'm not going to through each of these, but this shows you the really very large number of power plants and units that have been retired since 2010. And, again I don't want to go through all of them, but if you just take a look, they have all met the retirement date. And a couple of them, and if you scroll down to Huntington Beach, for example, about the fourth one down there, its compliance date was December 31st of 2020 and in fact they retired units 3 and 4 in 2012, eight years ahead of schedule.

The big one that took place and that is a focus of the other parts of this conversation on this panel was the San Onofre outage which took place in -- it was unplanned -- but in 2013. It was set to retire in 2022, so that one also happened well ahead of time.

The next slide I'm going to show you is those plants that are still using once-through cooling, and what the plants are. There again, I'm not going to through each of these, but if you look at the compliance dates in the middle, we are on track to meet all of those compliance dates. So we should see the retirements happening naturally and we don't see any system issues being caused by these retirements. Again, I think Neil is going to point out maybe one footnote to that but, for the most part, things are going along really well.

What does this all mean in terms of reduced water? This was the whole point of the exercise in the first place, was to reduce the amount of water that was brought in, reduce the impingement of marine animals that get caught in the intake structures and the small ones that pass through but then through the heat process die off, and I think the results are pretty impressive.

The blue line at the top is the design flow rates for the suite of power plants that I just showed on the prior two slides.

The green line shows those design flow rates but reflecting the actions of the power plant operators to reduce ahead of schedule those power plants that were either no longer needed or otherwise could be retired. And then the red line is really the most important one and it shows that the actual flows, the actual intake of seawater is significantly down and trending downward and should phase out by the end of the compliance period for the last of the generators. The reason that line is so much lower is because the annual capacity factors at most or all of these plants is significantly lower than the design rating, so you would expect that the actual water consumption would correspondingly be less.

So the reason we have been successful is attributable to a number of factors and we cite three here. We have increased our contracts for preferred resources to reduce demand. This includes energy efficiency, demand response, DG and energy storage. We have had some upgrades to our transmission infrastructure particularly in the LA Basin that has really helped the situation. And, finally, we have had some repowers where we are still relying on some conventional generation to meet the needs of the various places where these plants are located.

So, in conclusion, again we don't see any need to change any of the compliance dates going forward. The operators are all moving to either retire or repower or otherwise take action to get off of once-through cooling. Again you'll hear from Neil about one possible change to that. And we will continue to take a look at this closely. And the SACCWIS is going to be around until this process is completed, in the next decade, and all the plants are no longer using once-through cooling. Thank you.

MR. MILLAR: Thank you. I'm Neil Millar with the California ISO and I'm pleased to take the opportunity to walk you through our current reliability results for Southern California overall from a transmission perspective.

The first thing I will do is -- the first thing I will do is get to the right slide. Thank you.

The first thing I'd like to do is just to reset somewhat. As Chairman Weisenmiller indicated, we are on the trajectory that was established several years ago, both to address the needs of once-through cooling generation retirement in the San Diego and Los Angeles area as well as to accommodate the loss of the San Onofre Nuclear Generating Station. As we've gone through the several years, obviously certain projects, we have had some generation retire earlier than planned, others later, also of course the transmission reinforcements have also had to be tracked as we go through. So there have been some minor updates and I'd just like to touch on some of those.

But first I'd just like to remind people that the fundamental issues we were dealing with here was that with the loss of San Onofre, fairly critically located between the San Diego and the Los Angeles Basins, that created the opportunity for both thermal-loading problems as well as voltage-stability problems.

San Onofre had really been the anchor both for a source of power and reactive current supporting the voltages in the area. So it really was a critically located plant, so it did have quite an effect on our need for transmission planning, which had already been moving forward to address local capacity needs with the retirement of the once-through cooling, but this was an additional challenge.

Now this graph is fairly busy but it does provide the detail and overview really that overall, even with the retirement of San Onofre we're planning around a major reduction of the gas-fired generation fleet in the LA and San Diego areas. We have listed all of the different units retiring here as well as the new additions that are either -- have already come online or are in the process of being developed. But at the end of the day less than half of the generation that's retiring is being replaced with gas-fired generation and there is a significant reliance on preferred resources both embedded in the energy forecasts we received from the Energy Commission as well as additional procurement of preferred resources outside of the forecast.

So the mitigations that are under way are trying to focus both on the voltage-control problems as well as the thermal-loading problems into the area. If we could move to the next slide, please. I'll give up on this.

The mitigations addressed a number of issues and included, as I mentioned, a combination of preferred resources and conventional transmission. Some delays have been encountered that have caused for slight shifts in plans. The Carlsbad Energy Center, which was originally expected to be online for the summer of 2018, was delayed due to prior legal challenges. The new online date is Q4 2018. What we did to accommodate that was that in the compliance date for OTC compliance for Encina units were deferred until December 31st to maintain reliability through the summer, so there was a delay but it was managed and being accommodated.

The Mesa Loop-In Project is a major issue for us that we're continuing to track. The original intention was to have that online as well for -- to address summer of 2021. The schedule there does look like the in-service will be pushed into early 2022, but I'll leave that to our friends from Southern California Edison to talk about in more detail.

That does create the possibility of the need to defer the OTC compliance of either Alamitos or, in the worst case, Redondo Beach Generation. We believe that relying on Alamitos is now possible, whereas last year there were concerns around whether or not Alamitos was a viable option to be extended. But that's a situation that is still too early to tell but that we will have to continue to track.

The Sycamore-Penasquitos Transmission Project has also experienced a slight delay. It was targeted for the 1st of June, to be covering the full summer season of 2018. It does look like that date now has been pushed to the end of June, which does create some reliability risk that operating procedures will have to be put in place to manage through the month, and we are hoping that that project doesn't experience any further delays. Next slide, please.

One of the reasons we mentioned that the -- about different changes through the time is that when we're looking at particularly the potential mitigations for a delay of the Mesa Loop-In Project, one issue we are concerned with and need to consider is that the energy forecast or the demand forecast for the Southern California Edison overall and the LA Basin, in particular, has jumped again from last year's projection to our projection for this summer and for next year. So we are looking at for 2019 having to consider potentially higher loading levels going into the later years than we were projecting last year.

So this graph indicates roughly an increase of about 1200 megawatt peak demand forecast increase for the 1-in-10 scenario for the Southern California footprint from the 2017 IEPR used providing results that we use in 2019 local capacity requirements, compared to the value we used the last year in setting the 2018 local capacity requirements.

So the increased load level does have to be taken into account when we're assessing some of these alternative mitigations. So we will be following both the load forecast as well as working with Southern California Edison on trying to avoid an OTC extension if at all possible. Next slide, please.

One other issue that we're having to keep our eye on is that with the increased development behind the meter solar generation, the effective load carrying capability of the grid-connected solar and the qualifying capacity benefit of grid-connected solar has been dropping somewhat, especially in the San Diego-Imperial Valley combined area. Each year we're basically using the qualifying capacity that was determined through the previous year's work. So to some extent as the peaks continue to shift to later in the day, reflecting the impact of the behind-the-meter generation, we're always a bit, one year, behind in terms of how we're considering the capacity benefit of the grid-connected solar when we're doing our analysis. Next slide, please.

So just looking at the energy profiles and the demand profiles provided by the California Energy Commission, we are expecting that trend to continue as well as a bit more into the future. Where, in one year we're using qualifying capacity values that are derived for the next year's forecast, but as we get closer the peak shifts out a bit more and the qualifying capacity value is actually a bit lower than originally estimated. So this is something else we have to keep our eye on as we move forward. Next slide.

So overall we're continuing to work and coordinate both with the utilities and the state agencies to monitor these impacts and to make sure we keep the system reliable as we transition. We are on track but there are issues that, like I said, that we need to manage. Particular issues, again are the timing of the Sycamore-Penasquitos Transmission Line, the timing of the Mesa Loop-In Project, and assessing the impacts of the net load and shifting peaks as we look especially in the San Diego-Imperial Valley area, which is the one that relies more heavily on qualifying capacity at present from grid-connected solar.

Now I did want to mention that we have not addressed in this analysis any impacts of restrictions of Aliso Canyon utilization. We're leaving that for the more detailed discussion.

CEC CHAIR WEISENMILLER: Thanks, Neil. A couple questions. First I was just going to say in terms of summaries to the last IEPR, we had had about 10,000 megawatts of power plants retire, and looking at the forecast of the next whatever, again it is about another 10,000. So that's statewide and not specifically LA, but again we are having a major change in the fleet and in some respects we are only halfway through those transitions in the existing fleet.

You know I think at the same time the solar behind-the-meter forecast is one of the more complicated pieces of what we do. Historically, we were under forecasting. This time there were some parties -- actually the solar industry was saying we were probably over forecasting, but it certainly flattened out this past year, particularly with Solar City's scale-back of its operation, so it's been more -- instead of seeing major jumps in behind-the-meter solar, it's been more flattening out.

Now with the standards, that's going to continue to shift things. But I guess what I'm saying is we're certainly struggling to try to catch up with what's going on behind the meter and what's a pretty dynamic market that's, you know, not quite dealing with the tariffs, the solar tariffs, the tax credit side, the NEM. It's a whole bunch of parts of that stew which are going to really continue to make that challenging.

I think on the transmission side it sounds like, you know, again the Mesa Loop-In is probably the one and we need to spend a lot of time with Edison to figure out what's going on there, as well -- as the key project, is my take-away from your comments.

MR. MILLAR: Yes.

CEC CHAIR WEISENMILLER: I think just for the completeness of the record, Reiko, could you talk about what LADWP is doing on the once-through cooling, the study you're now conducting?

MS. KERR: Sure. So the Department is looking at a comprehensive study on the entire basin that incorporates all our future once-through cooling projects in the pipeline. And we're looking at 135 different scenarios ranging from plan as usual, the megawatt per megawatt, all the way down to zero megawatts and what the replacement can be as long as we're addressing: Resource adequacy; grid reliability; is it technically feasible within the timeframe that we're looking at; transmission reliability, simulating that on our system on an hour-by-hour basis; as well as the operational ability, when we look at it sub-hourly, moment by moment, second by second; and, finally, constructability, do we have the ability to do that within the basin. And each of those scenarios, it will start, if you will, the 135 scenarios in like a funnel, all

135 coming in, and as you pass through each screen, if you don't pass one screen you won't make it to the next.

So the end result of all those studies, the feasibility of which options are possible, will come out at the end in the scoring matrix. We have a number of agency or entities that are helping us with that study, independent experts. We have WorleyParsons, Navigant, Energia, E3, as well as DNV GL (phonetics), so it's a comprehensive study to assist DWP trying to figure out what that future in basin generation looks like or a combination of preferred resources, etc.

CEC CHAIR WEISENMILLER: When do you expect to reach a conclusion on that?

MS. KERR: So we're in the study process. It's getting close to being finalized. We expect by late summer we will have the results and we will start the public communication and outreach and start communicating the results of that study and informing our IRP. And in addition to that we're also -- a separate study is looking at what type of investments are necessary for LA to get to a hundred percent renewables. So the results of the OTC study will flow into that, but that's a longer study and will be 2020-ish.

CEC CHAIR WEISENMILLER: Okay. Well, hopefully you will be able to file at least a first study, the OTC study with the -- into the IEPR at some stage, --

MS. KERR: Yes.

CEC CHAIR WEISENMILLER: -- and you can try to take that into account in our planning.

MS. KERR: Yes.

CEC CHAIR WEISENMILLER: Thank you.

Anything else?

CEC COMMISSIONER MCALLISTER: Just a quick question on the slide order you showed the first slide on peak shifts. It's got basically a solar generation curve from a particular day, September 26, 2016. I'm wondering sort of why the discontinuity. Is that just a -- like why did you choose that particular day? Looking at that little bump in the afternoon, I'm wondering if that's a regular occurrence or if it was just, you know, a partly cloudy day or something.

MR. MILLAR: It's Neil here. As I recall, we actually just picked this day as a representative one that was showing a relatively high demand that day.

CEC COMMISSIONER MCALLISTER: Okay.

MR. MILLAR: And there wasn't any particular reason to focus on that day --

CEC COMMISSIONER MCALLISTER: No.

MR. MILLAR: -- other than it was representative.

The bump, I believe, was -- actually I have to double check that. I thought there was a slight cloud pattern that caused that.

CEC COMMISSIONER MCALLISTER: Yeah, that makes sense.

MR. MILLAR: I'd have to double check.

CEC COMMISSIONER MCALLISTER: Yeah. Thanks.

Appreciate that.

CEC CHAIR WEISENMILLER: So let's go onto the next presentation. Edison.

MR. MILLAR: Actually I'm afraid you have to put up with me for another presentation. We were asked to provide an update on the Pacific Northwest studies we were doing. If you want that in sequence or if you prefer to..

CEC CHAIR WEISENMILLER: Please go ahead now.

MR. MILLAR: Thank you. So the next slide, please.

So and just by way of background, each year in our transmission-planning process the ISO does look to see if there is any additional study work we should be taking on that's more informational, that's not part of our tariff obligation, that doesn't necessarily lead to or provide the basis for any transmission capital approvals. And this here, responding to our past efforts, the Energy Commission and the Public Utilities Commission made a joint request for the ISO to consider, through a letter that was submitted to the ISO on February 15, the request to undertake a special study or informational study looking at potentially accessing some of the additional Pacific Northwest hydro as a way to provide low carbon energy into California and to assess what role that energy could play in reducing the burden on the Aliso Canyon facility, more specifically. Next slide, please.

So the study focus is really on four different areas. First, looking at potential, more modest transfer capacity improvements on the AC and DC interties into the Pacific Northwest. Second, looking at or reporting on efforts regarding increasing the dynamic transfer limit on the AC interties. Thirdly, looking at the work Bonneville Power is doing on trying to automate additional controls on their system, focused primarily on the Pacific DC Intertie. And also working with primarily the Public Utilities Commission looking at the resource adequacy value of firm non -- zero carbon imports or transfers both on system as well as perhaps flexible capacity needs. Next slide, please.

So the study plan work is still underway. We developed, coordinating with the facility owners inside and outside of the ISO footprint, we have developed a draft scope. We're looking at the horizon, assumptions, methodologies, and scenarios that we would include in the study work. The draft scope has been presented to industry and we have received numerous comments. We are working through those comments now and we're hoping to finalize the study scope by mid next week. Next slide, please.

Just touching on the four areas in particular, the capacity of the AC and DC Interties, there are a number of issues there that need to be considered looking at the California-Oregon Intertie, in particular; looking at how certain outages and our consideration especially of certain N-2 or multiple contingency outages need to be taken into account. We're also needing to review how we're seeing congestion appear on the California-Oregon Intertie in our markets, where we see at time some congestion showing up in day-ahead that isn't materializing in real time. Part of that may be scheduling, in which case scheduling solutions may be more appropriate. Some of it could be congestion that's actually resolved in the day-ahead market and therefore if the right units aren't committed in the first place, then they don't show up and the congestion doesn't show up in real time.

We are wanting to look both in the short-term as well as touch on long-term benefits. In the short-term we're looking at more modest increases of seeing if we could move the ratings up to 5100 megawatts on the AC from the current 4800. And also trying to get a feel for what some of the long-term benefits could be, perhaps briefly touching on some of the proposed more capital-intensive solutions. There are some Greenfield projects, as stakeholders have proposed in the past, that we would like to at least touch on, but we're not expecting a thorough analysis in one pass. Next slide, please.

Regarding the increased dynamic transfer capability issue, that would provide additional value already in providing additional access in inter-hour scheduling. The dynamic transfer capability right now between -- with Bonneville Power is limited to 400 megawatts. There is operational work going on now to look at raising that to 600 megawatts. We would see our initiative reporting on the progress as well as trying to perform some assessment and identify what requirements there might be to even go beyond that. Next slide, please.

The work that BPA is doing on control automation on the DC Intertie would be more limited in this scope to reporting on the progress. This is an issue that would perhaps allow intra-hour scheduling on the DC Intertie, which we would see also providing value, with the question of what would it take and so forth, really falls to BPA in our coordination with them. And next slide, please.

The last issue, as I mentioned, is to look at the issue of resource adequacy value for imports, not just for system capacity but also to see if there is a possibility of a flexible benefit capacity benefit as well. And this is another issue that the ISO sees needing to address as well; that our current deliverability requirements for resources that qualify or resource adequacy right now are really limited to our system capacity analysis; and the question of whether resources providing flexible capacity truly need to also be capable of providing system capacity is an issue we need to come to terms with, and we see that being part of this discussion as well. Next slide, please.

So, as I mentioned, the scope has already been presented to stakeholders in draft form. We are looking at finalizing the scope. Originally we were more optimistic that we would have it out very early in May. Our stakeholders comments were quite extensive, so it is taking more time to go through that work than we had anticipated, but we are optimistic now that we'll have it out next week.

We are looking at getting preliminary results out in

November to align with the ISO stakeholder -- annual stakeholder consultation cycle for transmission planning, presenting final results at the end of January and our draft transmission plan, and walking stakeholders through that at our February 2019 stakeholder session.

And of course our final transmission plan would include the documentation of this work in March of 2019. Now stakeholders have raised the possibility that there might need to be some additional intermediate consultation and we're certainly open to looking at that as we go through the analysis.

So thank you. I will stop, if there are any questions.

CEC CHAIR WEISENMILLER: I just wanted to reiterate the priority that President Picker and I place on this. I think we'll hear later today about the CCST study which talked about generally an alternative to Aliso might be more transmission. Well, we're trying to get very specific in terms of, well, what is -- what transmission are we talking about and certainly what are the characteristics. And certainly this is -- a lot of interest in the Northwest in this, a lot of interest I think in California, so trying to pursue the specifics.

Certainly if we get to intra-hour scheduling on the DC, that would be a game-charger, you know, certainly easier for us. Dynamic scheduling would also help. And, you know, who knows, it's probably time to look at whether we can upgrade the transmission capacity a little bit. I don't think any of this -- although, again, if you come back and say we need a whole new intertie, I'm sure all of us would be fascinated by that conclusion, but I think we're expecting more, you know some degree of incremental upgrades.

MR. MILLAR: Actually we appreciate the comments because a number of stakeholder comments have been seeking to expand the scope to broader issues that we think would cause us to lose focus on the more specific issues you have asked of, so we're really having to prioritize and keep our eye on the ball on this one.

CEC CHAIR WEISENMILLER: See, I think part of the question is to the extent we have the IEPR, we have basically an evidentiary proceeding at the PUC that this could fit into, and so it is important to try to keep in mind of what the timing might be there.

Mark.

MR. ROTHLEDER: This is Mark Rothleder. I think it's worth noting that this work is actually in support of, and actually what we observed in the last four years, we introduced the real time energy and balance market, and what we're finding is, is that we're using more and more in real time the transfer capability in the system. And I think that's especially important in Southern California where we have about, at least in real time right now through the energy balance market, about 2,000 megawatts of transfer capability from the east getting accessed from the north. This transfer capability on a more real time basis is going to be important to help navigate and balance the system in Southern California, using really clean resources from the Northwest.

MR. MILLAR: There is only one other point I forgot to mention and that's despite I talked about this being -- taking place in the ISO transmission planning process, we have been receiving excellent support and cooperation from LADWP, so I just wanted to mention that, that the staff have been extremely helpful.

CEC CHAIR WEISENMILLER: Yeah. Obviously Picker and I sent a letter to the LADWP Board members, and they all seemed quite enthusiastic at least that we should be exploring this opportunity.

MS. KERR: Absolutely. With the interconnectedness of the grid, I think it was within all of our benefits to be involved in the analysis and study.

CEC CHAIR WEISENMILLER: Thanks, Neil. Now I guess it's Edison.

MR. CHINN: Good morning. My name is Garry Chinn, with Southern California Edison. I'm here to provide an update on some of our transmission projects in Southern California. Moving to the next slide, okay.

These projects are grouped together by certain headings. And this first grouping is what I call the load service. These two projects are designed primarily to relieve two existing substations. The first one is Alberhill. It is relieving the Valley Substation. The second one is the Riverside Transmission Reliability Project, which is relieving the Vista Substation.

So for Alberhill, the CPCN and application was filed back in 2009, amended in 2010, and it was a proposed decision that just came out last month to deny. And we just submitted comments in response to that just last week. OD day is still scheduled for Q4 of 2021.

The next one is the Riverside Project. That one is to, again, to relieve Vista Substation, also located in Riverside County. The Supplemental EIR was filed recently. And the deadline to submit comments is coming right up and the schedule for the next couple of years is still far out, in 2019, to get the final decision. The OD day for this project is further out in the Q2 about 2023. Next slide.

This next grouping of projects is related to delivering renewables. The first one is the Eldorado-Lugo, Lugo-Mojave Series Capacitor upgrades. It's scattered across a lot of counties. But the ISO approved the first element, the Eldorado-Lugo Series Capacitors back in the 2012-13 TPP. The Lugo-Mojave was approved a year later, in the next planning cycle.

This one, also the PAs were recently submitted. Scheduled start date for construction is now in 2019 with an OD of Q4 of 2021. This project is primarily designed to deliver renewables or generation in general from the Eldorado area.

The next project is West Devers. These are upgrading 230 kV transmission lines west of Devers Substation, located in Riverside and San Bernardino Counties. The CPCN was issued back in 2016. The BLM record decision came out in the same year, in 2016, and the construction just began early this year. The OD for that is Q4 2021.

The next slide are projects related to the local capacity requirements in Southern California. The first one is the Moorpark area. There are two projects there. The first one is Santa Barbara County, a reliability project. And the second one is the Moorpark-Pardee 4th Line. The first project is actually not as specific to LCR. It is to relieve a Goleta resiliency issue to upgrade the 66 kV system to strengthen the ties between Goleta Substation and Santa Clara Substation, to permit the -- the permit to construct was issued for this project back in 2015, but we're still waiting for the Coastal Development permits. Carpinteria has issued one in 2017, but we're still waiting for the rest of Santa Barbara County.

Construction began in October of '17 and schedule is Q2 of '19. Again, this project is not related to LCR, but the next one is, the Moorpark-Pardee 4th Line was approved by the ISO just recently, in the 17/18 TPP. It was approved as a reliability-driven project, but it also had an economic aspect to it and that line reduced the LCR need in the Moorpark area significantly, greater than 50 percent. Detail engineering is underway right now, and we are yet to pick a definitive construction start date, but the end date is clear. It's Q4 of 2020.

The next section there is the Western LA Basin LCR. The first project there is a synchronous condenser, the Santiago Synchronous Condenser, at 225 megavars. Located in Orange County. The ISO approved this several years back. Construction began August of 2016 and it went online December of last year.

The next project is the Mesa 500 [sic] kV Substation project, located in LA County. The permit construction issued February of last year, construction began in the same year in October. The OD date still remains in Q1 of 2022.

Right now we are doing I guess as well or better than expected. The OD date of 2021 hasn't moved beyond that. That's for sure. What has happened so far is some of the high-risk relocation aspects of the project is complete or near complete. There is an underground MDW water line that needs to be moved off the property. That has been completed. We are currently moving the transmission lines out of the way for the construction that is scheduled to be completed by the end of this month. So by the end of this month we would have basically the property be cleared for beginning the construction of the new facilities.

At this point in time we can't really commit to anything earlier than Q1 of 2022. The next, I guess, big construction piece is building out the 220 kV, the 66 kV, and the 16 kV switch rack and the connections. That would give us a better idea of whether we can move up the date. The last piece of the construction is actually the 500 kV piece and that piece is the piece we are looking to accelerate and to back into 2021. But we will know that with more certainty once we have completed construction of the other facilities.

And the schedule for completing the less than 500 kV work is actually around Q3 of 2019. So by May of next year we should know a lot more about the progress of that piece.

And that's all I had. Any questions?

CEC CHAIR WEISENMILLER: Yes. It's amazing how long it takes to do transmission. I mean there is obviously not as much transmission pending at this stage in the major downscopings in the last year or so, but still it's sort of amazing when you look through the list of when things had started or where they are, that it just takes time.

MR. CHINN: Yeah, it does take time.

CEC CHAIR WEISENMILLER: I'm sure the world's changing as you're trying to march forward.

Our perception is obviously Mesa Loop-In is probably the most important one there, from our perspective. Is that correct? I mean what are the other -- from your perspective, what are the other key projects from a liability-risk perspective?

MR. CHINN: I think for SCE the key two pieces for addressing the SONGS and OTC is really this project, which is the last transmission project to be built. I think of all the other projects, the loop-ins, the decoupling, the condenser, the capacitors evolved in place, this is the very last piece. That's one piece.

The other one is the procurement, getting the resources that we got, that was authorized to make up that deficit. It's also another critical piece to this. But as far as the transmission side of things, this is the last piece left to achieve the OTC compliance dates.

CEC CHAIR WEISENMILLER: And which of these is the project that is the only connection for the City of Riverside?

MR. CHINN: Back in the earlier slide.

CEC CHAIR WEISENMILLER: Yeah. I assume it's --

MR. CHINN: The one that says load service.

CEC CHAIR WEISENMILLER: Yeah, so no more.

MR. CHINN: The Riverside Transmission Project is the one for the City of Riverside. They are looking for a second point of service for their load.

CEC CHAIR WEISENMILLER: Okay. That's all I have. Anyone else?

MR. ROTHLEDER: Just for clarity, maybe this is a question for Neil. These projects, specifically local capacity projects, they are driven more by OTC and SONGS matters. But as they come online, will they have effects in reducing the gas burn need in the local area as they come on?

MR. MILLAR: Yes. We would expect -- like the capacity requirements we have identified and the procurement that was already authorized took into account those transmission projects at the time, so we wouldn't see these projects reducing the forecast requirement for gas-fired capacity, but we would expect some of these to also lower the total requirement for gas burned in some of these areas, especially as we're transitioning to faster, more flexible generation.

CEC CHAIR WEISENMILLER: Anyone else?

Okay. Thank you.

MR. JONTRY: Good morning. My name is John Jontry. I am the Manager of Grid Planning for San Diego Gas & Electric Company. And I'm here this morning to give you an update on the Sycamore-Penasquitos 230 kV line. Next slide, please.

Just real quick, I'll give you an overview of the SDG&E system as a refresher and then dive into the update.

This is the area that we serve and we serve all of San Diego County and the southern portion of Orange County, up to about Laguna Niguel. We serve at 1.3 million meters with about a population of about three million in our service territory electric. Next slide.

This is a very high level overview of the SDG&E system. We're connected to the east all the way out to Palo Verde and APS. Two lines, two 500 kV lines are our two main import gateways into the San Diego Load Center, connecting out to Imperial Valley where there is quite a bit of both conventional and renewable generation.

We're connected lightly through CFE/Cenace in Mexico and we have an import gateway connecting to Edison at San Onofre. The connection up to SONGS used to be much more robust when the generation was still at SONGS. The retirement of SONGS and then Encina, and then the other once-through cooling really changed the way our system operates. Next slide.

So the Sycamore-Penasquitos 230 kV project was initially identified as part of the plan of service for the Sunrise Power Link.

It wasn't approved as part of the plan of service, it was replaced by some other 69 to 138 kV upgrades. Later it became apparent as part of the once-through cooling of Encina that it would be, you know, very useful. And it became very apparent we needed to have it in place once San Onofre retired.

So the project was approved by the CPUC I believe in 2016. It is currently under construction. This slide shows you kind of where we are right now with the construction process. Basically, the largest and most difficult part of the project is installing the underground ductwork and vaults. A hundred percent of the vaults are installed and we're, you know, close to a hundred percent of the underground ductwork in place. The last remaining part of the ductwork is the bore underneath the I-15 Freeway, which is undergoing right now.

Like I said, the remaining work, completing the bore under the I-15 Freeway, pulling in the cable, completing the splices, we have pulled in most of the cable and are over 50 percent done on the splicing work. Basically, once the bore is completed under the 15, we'll complete or pull in the rest of that cable, splice it in, and that's really what's driving the in-service date right now. Next slide, please.

Like I said, completing the I-15 bore; finishing up a relatively small amount of 230 kV overhead work outside of the Penasquitos Substation, south of the Penasquitos; finishing the cable terminations, putting it in service and testing. Right now our current in-service target date is July 31st. And, like I said, sort of the critical path on that in-service date is completing the bore under the I-15 and then pulling in that last remaining piece of cable.

Really quick, to give you some upgrade on some other -- or update on some other major projects coming up in the next few years, not directly related to the once-through cooling issue or SONGS. The South Orange County Reliability Enhancement Project received CPUC approval a couple of years back and we're hoping to start construction on that at the end of this year. The final in-service date in the 2021 to 2022 timeframe.

As part of the once-through cooling and SONGS retirement we also identified four or five -- I believe there were five -- locations to upgrade or to add additional reactive support. Three of those are in service now, the Talega, San Luis Rey, and Miguel Synchronous Condenser Installations. The SONGS installation will go into service at the end of this year. I believe the only remaining one in our service territory is a 300 megavar SVC at Suncrest. That's a project being done by an outside developer and we don't at this time have an in-service date. I believe it's still working its way through the CPUC.

The only other project that I will give you a quick update on would be the Artesian 230 kV project. It is awaiting the final MND and I believe we're hoping to start or get a final decision and start construction next year.

That's all I have. If there's any questions...

CEC CHAIR WEISENMILLER: You know this helps. We have already been assuming Sycamore-Penasquitos was part of the key project. The synchronous condensers are also a key part of the element, but it does seem like a well position. I guess -- are you guys still pursuing flipping SWPL to DC?

MR. JONTRY: Yes.

CEC CHAIR WEISENMILLER: What's the status of that?

MR. JONTRY: Let's see, it's -- we submitted it last year to both the California ISO and to West Connects Interregional Planning -- or Planning Project and also as a reliability project to the California ISO. The ISO at this point hasn't seen the need for that project from a reliability standpoint. We're hoping this year the ISO will be looking at the possibility of reducing LCR RA needs in San Diego that will see some traction as an economic project.

We also understand there is at this point the -- we're also sort of waiting for to get guidance on ultimately what the change in RPS goals might be, what that ultimate mix and renewable resources will be. We think as a project it would be very helpful for developing additional renewables in the Imperial Valley and then points east. So right now we're kind of waiting on sort of a better look at it as an economic project and also as to help us -- to help meet some of the ongoing policy goals. But until we get more clarity I think on the ultimate -- ultimately where we go with the RPS goals, I think we're going to be still pursuing the project but it's going to be -- we're waiting for some of those drivers to materialize.

CEC CHAIR WEISENMILLER: Okay. I think the PUC's IRP decision is marching along, so some guidance is coming.

Anyone else?

Okay. Thank you.

MR. JONTRY: Um-hum.

MR. ZOIDA: Good morning, everyone. My name is John Zoida, with Southern California Edison. I work in their Wholesale Procurement Business Unit. I am currently leading the Moorpark LCR RFP with my colleague Shawn Smith. I also led the PRP1 and PRP2 RFOs, and we'll get to that at the next presentation by yours truly.

So earlier this year we launched the RFP for -- to address the Moorpark LCR need. We also have in our target to procure resources to meet our Resiliency Objectives. But the LCR need has been identified by the ISO as one particular transmission contingency. I have information in the back-up slides. Actually there were two transmission contingencies, but one of them is being addressed by the Moorpark Pardee line that Garry Chinn, my colleague just spoke about. But the other contingency is going to be addressed by Energy Resources, procured via this RFP.

So just a little background. The ISO each year revises or reassesses the LCR need, the subject matter here of course is the Moorpark subarea of the Greater Big Creek LCR region. The LCR need could be affected by such things as load forecast updates -- we have heard a little bit about that; new transmission projects -- we heard about that today; resource retirements, whether expected or actual; and new build contract delays, contract terminations, all of the above could affect the LCR need.

But where we stand today the ISO has identified, preliminary I believe identified a megawatt need to address this contingency, this remaining transmission contingency, and they gave us a range. It's 102 to 164, and this is dependent largely on the area we're talking about. And I did skip over a line here on point number 1. The areas we're looking at, Moorpark is just the name of the subregion. It's really the distribution and, to some extent, the transmission systems served by the Goleta and Santa Clara Substations. So really this 102 to 164 depends on where the resources are located. There is some interplay between Goleta and Santa Clara and there is some interplay between whether a resource will be a distribution-connected resource or a transmission-connected resource.

With that, let me state we have heard a lot about DER RFOs or DER’s, Distributed Energy Resources. This RFP is not a DER RFP. It's all the above, both of the above. It's transmission and distribution resource. So there is some interplay between those two locational dimensions and what we ultimately need. Will we need more -- closer to the 102 or the 164.

So that is the primary focus of this RFP. It is indeed the LCR need. That's what we're authorized to procure, of course subject to ultimate PUC approval. But we also have an objective, a resiliency objective in the Goleta area. Edison has identified a particular issue that can occur with respect to the only two large transmission lines feeding into the Goleta area, if you will. And by Goleta I mean Carpinteria; Santa Barbara; Isla Vista; the campus, the U.C. Santa Barbara campus; and several others, Montecito, and several others certainly that you have heard in the news this year, and more.

So this is -- this resiliency objective is not mandated. It is an objective by Edison. The quote-unquote megawatt objective is about a hundred megawatts, but anything sited in the Goleta area will count for LCR. It will be casually referred to as a two-for. But that doesn't mean that we will be siting everything or even anything in Goleta. We hope to. We expressed a preference to sellers and the offerors to site in Goleta over in the Santa Clara area, but we'll see once we receive offers and assess those offers for economics as well as viability.

Going on to page -- the next page, page 3. So just on a high level, we're looking for additional resources. These are both in-front-of-meter and behind-the-meter resources. And, as I said a moment ago, this could be distribution connected and transmission connected.

In the Santa Clara area only preferred resources are permitted to participate. If we get a gas-fired proposal in the Santa Clara, it is ineligible, we will not consider that. However, in the Goleta area we are allowing to -- for offerors of natural gas fire facilities to submit an offer. Edison is a strong proponent of clean power for our grid, but we want to look at offers for natural gas fire facilities as potential consideration should preferred resources not be able to meet the resiliency needs. It's for a consideration.

More on RFP eligibility. The technology has to be commercially proven in parts or in whole of the project. And delivery at this point needs to be by 1/1/2021. Where that comes from is the retirement, the ultimately deadline for once-through cooling retirements. That's where we get that from.

Other focal points of the RFP are: Preferred resources in disadvantaged communities. Within the footprint of our RFP, there are certain communities identified as distributed -- disadvantaged communities, or DAC’s for short. There are several areas located in the Ventura County that are identified as DAC’s. So let's hope that we get offers for preferred resources in those areas. The Goleta area doesn't have any -- at current doesn't have any regions identified as a DAC.

We also encourage participation by deferred and diverse business enterprises, whether they are a DBE themselves or they have DBE goals with their own suppliers for equipment and installation, and so forth. I think I stated already resources sited in Goleta would also address -- or would address both reliability, LCR, and resiliency.

And of course within the Goleta -- now I'm talking within

Goleta, we do have a preference for referred resources over natural gas, to repeat myself there.

So there are challenges and there are encouragements with respect to this RFP. The delivery by January 1st is really going to be a challenge. There are several long lead-time items. One of them is the interconnection process, especially with respect to the in-front-of-meter. And the lower the circuit level they're interconnecting, the shorter it will be, and conversely the higher when you get to the 66 kVs or even the transmission. It's going to be challenged to meet this 1/1 date.

Behind-the-meters installations, they don't necessarily depend on that -- there are other challenges with behind-the-meter installations, but this interconnection is not noted as one of -- a big issue for behind-the-meter.

More on the interconnection process. Unfortunately, it's more in serial and not in parallel with this RFP process, which is almost a year -- about a year long. And then there is the PUC approval process. So rarely do you have offerors willing to -- they're certainly investing time and money into projects even right now, but in order to start construction on the interconnection, they will likely wait for PUC approval before doing that. Now it would be great if they started shelling off a lot of investment and money prior to PUC approval and that could make a date like 1/1 a lot more feasible.

We are working with our own interconnection group as well as the ISO in seeing if we could work on that date. That date is very granular. Again, it's based on the once-through cooling, but when does the actual LCR need materialize; is it later in the year. So we're working it. We're hopeful to be able to push that date out a little more. We don't know exactly how much more, but it will just be in terms of months.

Encouragements. I did take a peak at our interconnection queue. The latest interconnection queue for in-front-of-meter projects closed at the end of April. We -- it's public information, so I looked on Edison's public website. We are still populating that spreadsheet, if you will. But we do see a lot of megawatts being -- that has entered into the transmission queue -- I'm sorry. I should say the distribution queue process. I was only looking at the WDAT. I have not looked at the CAISO interconnection transmission queue process.

We see a lot of megawatts. I'm not saying those are viable projects. I'm not saying they're nonviable projects. But there are a lot of megawatts and that's encouraging. The super majority of those megawatts are energy storage, but I do see some fuel cells, fuel cells coupled with energy storage. I see a couple of solar. We really want generation to be a part of this RFP, but a supermajority, like I said, is energy storage.

And we also have excellent support from the communities in Ventura and Santa Barbara. Namely, there is a nonprofit called Clean Energy 805. They're doing a lot of good work. We're helping them out, we're supporting them to a certain extent. But they are playing a really good matchmaker between offerors -- or developers, I should say, and businesses that might be inclined to install some behind-the-meter storage, for instance, or rooftop solar behind the meter as well.

There are some back-up slides. Feel free to ask me questions about the entire deck or anything else you could consider.

CEC COMMISSIONER MCALLISTER: I wanted to ask about the criteria for evaluating EIRs in this RFP process. So why don't we just get a sense for the hurdles that preferred resources face and what criteria you're using to kind of evaluate them to judge whether or not they meet your resilience and reliability --

MR. ZOIDA: Right.

CEC COMMISSIONER MCALLISTER: -- requirements in that context. And so you mentioned storage and solar behind-the-meter resources. I'm wondering about demand-side resources, sort of more traditionally conceived as, you know, energy efficiency and demand response itself.

MR. ZOIDA: So your question is how do we evaluate these in terms of everything, really viability, economics?

CEC COMMISSIONER MCALLISTER: Yeah. From a bitter end of this RFP, you know what hurdles would they have to get over in terms of proof of reliability and resilience support.

MR. ZOIDA: Right. So in the RFO instructions, and we also had published some guidelines, it's really the burden of proof is on them to convince to us how you can site a project and get it online by, in this case right now we're at 1/1/2021. Do you have permits on hand? Do you have site control? Are you in an interconnection queue process? If you're in Interconnection Queue Cluster 10, which was last year's, hey, more thumbs up. If you're in 11, it's going to be tight. So we do screen for viability. And we offer -- we feel we give the offerors tools to fill out their offeror package and convince to us where they're at and what kind of experience they have in procuring financing and procuring the equipment.

So we will need to assess the viability, certainly, of these projects. So that's really step one -- well, actually step one is are they eligible. That's the first stream.

Step two is we assess their viability. Is this just pie in the sky technology or is this lithium batteries that have been fairly proven or proven flat out. And then from there we move onto the valuation, we move onto the economics, the least cost part of the least cost best fit -- and then we look at the best fit in terms of selection. So that's the skinny of the gamut.

Is it a hundred percent scientific? No, there is some art in there. We have a big team of engineers. They will be assessing project viability. We have our interconnection people that will be assessing the viability of the interconnection. So we're hitting this at many different dimensions here. We understand the viability is key here and 1/1/2021 is right around the corner. And we almost don't have a second bite at this.

CEC CHAIR WEISENMILLER: The thing I found -- I found a couple things interesting. One was obviously we were dealing with the question of resilience in the number context and the PUC's new adaptation workshop -- OIR. But critically you have defined for resilience purposes here how to keep the grid -- and how to keep the lights on if you lose the transmission in this area.

MR. ZOIDA: Yes, sir. So we looked at reliability as the uninterrupted --

CEC CHAIR WEISENMILLER: Right.

MR. ZOIDA: -- flow of power. And reliability is like a bounce back, the N-2 happens. N-2 is our nomenclature for those two lines going up.

CEC CHAIR WEISENMILLER: Right.

MR. ZOIDA: These two lines go out. How quickly, and we -- how quickly can we bounce back. I was going to say and reliably bounce back, but I don't want to conflate terms. Yeah, so that's how we're defining it. It happens and then how do we get back to it, back to delivering energy.

CEC CHAIR WEISENMILLER: And, again, I'm just trying to figure out the context if there are any really load-management options or demand-response options which obviously don't pull you into all the interconnection --

MR. ZOIDA: Yeah.

CEC CHAIR WEISENMILLER: -- permitting issues but have a different set of reality issues.

CEC COMMISSIONER MCALLISTER: Yeah. And I guess -- so you mentioned interconnection as sort of like one of the -- one of the bottlenecks that projects have to get through; well, that's not the case with some demand resources. And so, you know, if we're going to make our buildings themselves part of the solution, then those criteria may look pretty different from -- well, they will look very different from a generation project or a storage project. And personally I think those have to -- those are going to end up being -- they could end up being part of our least-cost solution, but it's a completely different business model or a very different business model from some of the other options. And so, you know, I very much would encourage that.

And I guess maybe just on Bob's point, you know now that you've been through several iterations of preferred resource RFPs, I'm kind of wondering what hard lessons you've learned about -- or what lessons you've learned about sort of getting them through that whole process and to reality out the back end of the PUC approval.

MR. ZOIDA: One lesson learned is certainly the viability. And, as I just explained, we're going to be attacking that in many different dimensions, the interconnection side, the technology side, so we really need a robust viability assessment.

Number two, and this is on the slide of the next presentation, what we want to do better at is when we are selecting offerors -- well, we select offers, but we also have to look at offerors. So we don't want to select a behind-the-meter aggregator/developer, we don't want to select two of them that are going after the same market segment necessarily. But if their project sizes are small, maybe there is an exception to it. So there is another lessons learned is really be strategic in your selection of the offerors and what market segments they go after.

In-front-of-meter, it's the interconnection process where we're stuck with it. It's a long lead item. We are working more and more with the Interconnection Group, though, unlike years past where we're really siloed, we are working lock step with them, so I think that's going to be more valuable. That is certainly a lessons learned.

And the Commissioner made a very good point, when you're bouncing back from an N-2, the behind-the-meters projects don't help you get back. You need the in-front-of-meters, but then once you're cobbling together the grid and it's starting to become operational, if you could bring, ratchet back that demand a little more, that's where the behind-the-meters will come into play for resiliency now. I'm just talking resiliency, not necessarily the LCR need.

If I may, I could go on to the PRP.

CEC CHAIR WEISENMILLER: Please.

MR. ZOIDA: Yes. Thank you so much.

So as you're queuing that up, I think my colleague Sergio Islas last year presented to this group. Just to maybe help people out, if they haven't heard about the PRP or hadn't heard of it for a while, this is an initiative. It's taking place in the certain portions of Orange County and specifically it's those distribution areas served by the Johanna and Santiago A Bank Substations. The PRP, the pilot, not the RFO, the pilot really came to be for a variety of reasons: The SONGS outage; the once-through cooling retirements; population, significant expected population business growth in this area; as well as California policy preference for preferred resources.

So we conceived and implemented this PRP and it's really divided into acquisition of resources, then you have the deployment or them coming online, operating -- that's the third, and then measurements. So I'll go onto the first page.

And this first page looks at really the first two, the procurement and the deployment. Now the procurement over the years, I look at it as fairly successful. We started with the 2013 LCR RFP and we stated a preference for the preferred resources pilot area -- I'm sorry. Yeah, the preferred -- the PRP area. And we signed up a lot of contracts for those.

And you see in this table with a lot of numbers the -- and the procurement source, you see LCR throughout here and it's divided by the first column is the resource type. So you see that we signed up many megawatts from that LCR, the 2013 LCR program. So, for instance, energy efficiency, we signed up 158 megawatts. The negative 4, the numbers in parentheses, that was the change from what Sergio had presented to this group last year, so that could have been -- likely it's a contract terminated. I don't have the details, but that's likely what it was.

So a fairly robust procurement. Looking at these larger numbers, the deployment is certainly another story. We were hopeful that these numbers would have been a bit larger, but we're hopeful that throughout this calendar year and into next, the numbers will -- in these last two columns, the numbers will certainly increase. We're very hopeful of that.

You could certainly ask questions at the end of this on this slide, but if I may turn to the next slide. In looking at the progress of the pilot itself, the PRP pilot, again those four dimensions or milestones here. Acquisitions seems to be really on track. We're leveraging -- most RFOs we go out with we give a -- even if it's not PRP specific, we give a plug or a preference or encouragement for those resources in the PRP area.

The deployment, we're meeting some challenges. There are project delays and terminations and, you know, approvals that are needed. So we're -- that's a bit challenged, that aspect.

And then operations and measurements, really a wait-and-see. We have some online now. We are taking some measurements. We're identifying peak days and seeing how the resources that are have been deployed, how they will contribute to meeting the days demand electrical needs.

As far as preferred resources in general, a good encouraging thing is the solicitations that we do run, we have x times need that are contributing into our RFPs. It's highly competitive, so that's good news. We see improved prices each time. The last several RFOs, RFPs, we've seen mostly energy storage. I gave you an insight into the WDAT grid. When I ran the PRP2 RFO a year or so ago, I think we signed up -- 90, 95 percent of what we signed up was energy storage, whether in front of meter or behind the meter. In front of and behind, that was a nice, even split, but it was heavy on energy storage. There was a little bit of solar in there.

And I think I talked about -- the bullet 2 is behind the meter there are deployment challenges, including developers targeting the same markets. There is also a challenge which I didn't really put here is sometimes it's difficult to get an installation in a building. You might have a disconnect between a tenant, the renter of the building, and then the owner. So you have multiple parties to contest with. Sometimes the building owner, they have a great amount of money each month for rent but do they want to disturb their tenants for in their mind not as much of an additional revenue stream, is that really worth it. So there are certainly challenges with both in front of and behind the meter. This was just an example of the behind-the-meter challenge.

And I did allude to that we're looking to improve our strategy of selecting offerors, not selecting behind-the-meter aggregators that target the same market, to the extent that there is too much chasing too little.

And then we have begun outreach, also customer, retail customer outreach on our own. We haven't done that in the past.

And we also learn, we improve our pro formas all the time and you put in additional requirements for the offerors or sellers to abide by.

So that's the report out for the PRP.

CEC CHAIR WEISENMILLER: Now when you talk about behind the meter, is that primarily commercial or is that multi-family or issues --

MR. ZOIDA: All the -- yes, sir. It's industrial, commercial, and residential.

CEC CHAIR WEISENMILLER: Okay.

MR. ZOIDA: So, for instance, one of the -- one of the companies we signed up pursuant to the PRP2 RFO, this company, their foray is -- their target market is residential. So that was nice. Most of them are commercial, industrial. So it's all of the above really.

CEC CHAIR WEISENMILLER: All of the above. And, again, just trying to understand your take-aways on sort of what's worked the best or been the most problematic?

I mean obviously looking at the numbers, you've got pluses and -- you know, as you indicated, there is a pretty big gap between what's been procured versus what's been deployed.

MR. ZOIDA: Right.

CEC CHAIR WEISENMILLER: And presumably, you know, you see some trail off but you see some addition, so it isn't all contracts going by the wayside.

MR. ZOIDA: Right. There is something else I think we should look at as well. It's -- I think one lesson learned would be our offerors over promising. Do they think there is more potential than there really is.

Now we think in theory we have so many hammers in our contracts, development security, performance assurance, and other issues, and in the meantime they are spending money throughout this whole process. We would think those are incentives enough for them to understand that -- they understand what is the market potential. So if we could also do our own assessment and not sign up, just pure example, not sign up a 50-megawatt project if we don't think there is 50 megawatts worth of business to be had. That's a big one.

Now the in-front-of-meters, barring the lengthy interconnection process, we found in-front-of-meter, especially energy storage as those are pretty viable. Those get built fairly quick in the grand scheme of things. Solar, PV, ground-mount, for whether it's in front of or behind the meter, that might be a little more challenging in the Goleta area, just given its make-up is highly residential. So that might be a challenge. I'm not saying an impossibility. Rooftops would be a better bet, but solar would be probably a little more challenging than energy storage.

CEC COMMISSIONER MCALLISTER: I mean I guess just a comment on the demand side stuff. I mean historically a lot of energy efficiency has happened over in kind of a bolted-on thing called the efficiency portfolio and not part of procurement. So I'm actually really hoping and encouraged by the preferred resources pilots and just hoping that we can make that a success. And certainly I think it's sort of prime time for the efficiency community to really see the seriousness of that, of the need to have that be a success.

At the same time I do worry about kind of the hammers that you, you know, mentioned, and absolutely accountability has to be there, but the nature of that endeavor is that the more we sort of get up under the hood and expect lots of data collection and increase the transaction cost, you know, because it's diffuse, it's a diffuse activity, and so the temptation is to sort of really be overbearing on the M&V or the measurement verification of all these savings. I guess I'm wondering how much Edison has embraced sort of looking at analytical methods to gauge the impact of the demand side aggregated resource and how you see that, sort of the contracting and then the verification on your end to really show that delivery is happening, has happened, and that you can expect it. You know what sort of tools have you developed, if any, to assess demand and reductions or demand manipulation as a preferred resource, sort of that in that context going forward?

MR. ZOIDA: Unfortunately I'm not qualified to answer that. I could take a guess, but I just don't want to be wrong. I believe this is being recorded. I can take that back and make sure to get that question verbatim and give you a written response; is that -- I hope that's acceptable.

CEC COMMISSIONER MCALLISTER: That's fine. I'd love to, you know, have that interaction actually with who the relevant staff is. You know we're in 2018 and we have a lot of analytical tools that we didn't have even a few years ago, so I think that's a way to ease this transition into a broader array of demand side resources that maybe we wouldn't have been able to, you know, five or ten years ago.

MR. ZOIDA: Right, right. As far as hammers in the contracts, I used the word first and then you used it, there is nothing noteworthy changing from -- we have developed throughout the many years of being in procurement, but from the past couple RFOs to now there hasn't been anything that has drastically changed or the hammer got to be a sledgehammer now. And we have signed up -- there are commercially-proven contracts, they have signed up, they have had -- there are risks to be had on both sides. And we have both entered into these agreements. Deployment is slow on some respects. We get that. But there is not a drastic change in hammers between recent RFPs where we've had entered into contracts, but still you deserve an answer to the -- to your question.

CEC CHAIR WEISENMILLER: Thank you.

MR. ZOIDA: Thank you.

MR. THAI: Good morning, everyone. My name is David Thai. I'm with San Diego Gas & Electric, part of the Electric and Fuel Procurement Organization. I'm providing an update today on the Carlsbad Energy Center and SDG&E's Preferred Resource Procurement.

As you have heard from Neil, with the ISO earlier, the

Carlsbad Energy Center is expected to be fully online in Q4 this year. Per our last conversations with NRG, they expect testing to occur this month. And, for those of you who are unaware, that's a 500-megawatt conventional gas-fired generation facility in the Carlsbad area of San Diego County.

As of April 25th, SDG&E received a proposed decision from the CPUC approving a number of preferred resource contracts, five battery-energy storage contracts, and one demand-response contract, in total equaling 88 megawatts of the local LCR capacity. That includes two-utility owned projects of Fallbrook and Miramar, of 40 and 30 megawatts respectively. And there is a demand response resource in there, four and a half megawatts.

In conclusion, per the CPUC's 2012 long-term procurement plan track for a decision authorizing SDG&E to procure, 700 to 800 megawatts of local capacity, SDG&E has secured 500 megawatts of conventional generation per the Carlsbad decision, as I mentioned earlier, and now a total with -- given the 88 megawatts of approved preferred resources, SDG&E has 144 megawatts of in-basin preferred resources counting towards that track 4 procurement target.

That is all I had. Are there any questions?

CEC CHAIR WEISENMILLER: Yeah. Trying to get a better sense of on your list of Preferred Resource Projects, you've got the expected online date. I was just trying to understand, I think that's Ohmconnect is probably the soonest one and the rest go out, you know, all the way up to several years back.

MR. THAI: That is correct.

CEC CHAIR WEISENMILLER: So that -- I'm assuming part of the question on this is just going to be tracking progress going forward and seeing what we get out of this. It is an interesting mix, as you know. You indicated most of these are storage projects.

MR. THAI: That is correct.

CEC CHAIR WEISENMILLER: And we've -- just those seem to be the simpler ones, at least on the front side of the meter to make happen.

MR. THAI: Right.

CEC CHAIR WEISENMILLER: Any issues on interconnection with these or...

MR. THAI: None that we're aware of. These dates are, again, two to three years, --

CEC CHAIR WEISENMILLER: Right.

MR. THAI: --, you know, out, so.

CEC CHAIR WEISENMILLER: Yeah.

MR. THAI: But we have not heard of any issues regarding these contracts.

CEC CHAIR WEISENMILLER: Okay. Well, thank you.

Anything?

CEC COMMISSIONER MCALLISTER: I'm wondering -- sort of again I'll hammer on -- to use the hammer again -- hammer on the demand side and particularly the -- sort of the efficiency demand response. You know, I think that's a good decision to include that particular project, but I guess I'm wondering did you get sort of a broader array of technologies in the RFP and these are the ones you ended up with or was this sort of representative of the group that you got?

MR. THAI: This is representative of the group we received. There was another energy efficiency project that was -- that was actually taken and approved back in -- actually I take that back. There was an energy efficiency project that was approved, I don't have the date in front of me, but it was 18 and a half megawatts worth of energy efficiency.

CEC COMMISSIONER MCALLISTER: In a previous RFP?

MR. THAI: In a previous RFP, --

CEC COMMISSIONER MCALLISTER: Okay.

MR. THAI: -- that is correct.

CEC COMMISSIONER MCALLISTER: So -- but this was strictly an LCR procurement?

MR. THAI: That is correct.

CEC COMMISSIONER MCALLISTER: Okay. Okay. Thanks.

CEC CHAIR WEISENMILLER: Thank you.

MR. RONDOU: All right. Good morning. My name is Jason Rondou. I am the Manager of Strategic Development and Programs at LADWP. I'm going to talk today about -- touch on a few highlights of our Ten Year Transmission Plan and touch on preferred resources, including some of the changes that we have undertaken recently, particularly in the last couple years following Aliso Canyon. So onto the next slide.

Our Ten Year Transmission Plan is really, you know, undertaken to ensure reliability, but it was becoming exceedingly more important in the last couple years in light of two major efforts that we have undertaken. And the first is the OTC study that we have undertaken. And it was mentioned earlier that we're going to get some of the results from that shortly here, this summer. And I think that's going to have a pretty substantial influence on this. And I think the second one is our 100 percent renewable study that is going to be completed over the next couple years, and I think that may have a very, very large impact on what our outlook looks like. But even before those we do have a number of substantial upgrades that we recently completed and that we're going to complete in the coming year.

So in the next slide you will see an overview of our sort of what we call out-of-basin and in-basin transmission system. So on the left-hand side, I'm going to start with C, that's our PDCI segment that comes into the city there at Sylmar (phonetic). And then the D is our Owens Valley system. And I'll talk in a second about a substantial amount of solar that's now coming in through that area. And then segments A and B what we call our Vic-LA, or Victorville-Los Angeles path. And, you know, I'll mention some of the future upgrades and potentially very, very substantial future upgrades through those lines.

Locally we have four generating stations, gas-fired generating stations, and three of those are subject to the OTC repowering study. And those provide reliability must-run and voltage support local in-basin as well.

And then the last one, our Valley Generating Station, which is kind of in the center of that map there, one really interesting point here is the two lines that bring power out of Valley were slated to be upgraded this past winter. And we elected to defer those upgrades to ensure reliability and so you're starting to see the trade-off between moving towards a long term where we're less reliant on gas and then maintaining reliability in the short term. And so I just wanted to kind of highlight that and the importance of those short-term challenges.

Onto the next slide is where I'd like to highlight our Barren Ridge Transmission upgrade. And what this allowed us to do is bring 1,000 megawatts of solar into our system. There is a number of solar installations here, all of them on the right-hand side of that map, have come online in just the last couple years. And we actually have a number of projects that are also slated here as well.

So on the next slide you can see, you know, in addition to that recent upgrade we are targeting a further upgrade of that, of another 700 megawatts. And to give context for those -- most will be aware of this, but for those that aren't, our peak demand is around 6400 megawatts. So these are very, very substantial numbers for us.

And you will see that we have got a whole lot of solar and renewables concentrated coming into this one area, and so the one benefit that we get here is we're leveraging an existing resource, right. But the trade-off here is the geographical diversity. And so the upgrade that would provide more energy capacity from Castaic helps mitigate that a little bit. And so you could see again, you know, we've got these constant trade-offs between leveraging these existing resources and providing geographical diversity, but we've put a big effort in to try to mitigate some of the shortcomings there.

So onto the next slide. And, again, this is another near-term project that we expect to have done by 2022, is to have upgrades of about 450, and it might actually turn out to be closer to 500 megawatts here. And this, you know, will largely be equipment replacing, so replacing transformers and SVCs in order to gain that expanded capacity. And you will see in a moment the importance of this because as we move further outside of Los Angeles, you will see that we have a whole lot of opportunity to bring in new renewable resources, but to be able to get it home we need to have these other upgrades in place.

And so on the next slide here, with the divestiture of coal here we've got another, you know, over 600 megawatts of potential capacity on our transmission line to bring that to home. And so, again, this just further drives home the point of to be able to leverage this we need to continue the local upgrades as well.

So on the next slide here at Mojave, so this one is a little bit closer and we actually have a number of potential projects that are being proposed currently here. And so this is another 700 megawatts of transmission capacity that we have the rights to and so there's, in this area I think, a whole lot of solar and potential opportunities for solar and storage.

So on the next slide some of the longer-term potential upgrades that we have here. And these, again, become increasingly important when we're talking about a hundred percent renewable cases, particularly the Vic-LA on the left-hand side, potentially even converting these to high-voltage DC or AC. And so now we're kind of getting far away from the low-hanging fruit of the previous upgrade that I mentioned, about the 450 megawatts.

And then on the right-hand side, you know, doing life extensions for a southern transmission system in order to bring home 600 megawatts, potentially more than 600 megawatts in the future as we divest from coal at IPP as well.

And so to kind of recap on the next slide, again we've got these near-term trade-offs. We've got these challenges about maintaining reliability versus moving more and more towards a hundred percent renewable case, and again I think these ambitious transmission upgrades may grow in scope I think in the next couple years as well.

And so in the interests of time I think we'll jump right into the preferred resources section here. And I just want to, on the next slide, touch on a few of the things that changed in just the last couple of years. And so we accelerated plans for similar energy storage projects following the Aliso Canyon incident. And we accelerated existing energy-efficiency programs, in some cases dramatically accelerated our energy-efficiency programs.

We launched new demand response programs, one called the Summer Shift. And then on the local solar side, we had a number of opportunities to expand or continue programs that were in place and that were previously scheduled to sunset. And so that will take us to our next slide, where we talk about some of our local solar goals.

LA was recently recognized as the number one city in the country for local solar, and so that means behind-the-meter solar. This doesn't count anything outside of the city territory. And all that totals to around 300 megawatts. Well, we've got goals for about 1500 megawatts. So while we've made some really substantial progress, it's really taken a portfolio approach to doing behind-the-meter solar which has its benefits but also its limitations. We've got our Feed In Tariff Program where we buy all that energy, and it's power purchase agreements. And the significance of that is we've got a little bit more control over it and we've got the ability to count our renewable energy credits for those.

We have a portfolio of programs that really address equity and customer choice issues, and so these don't really add a whole lot to our renewable portfolio, but they are significantly important for strategic and for equity purposes.

And then finally LA does a little bit of constructing and operating and maintaining of our own solar. And this chart here just gives us a sense of the magnitude of what we're, you know, planning on for local solar. And so, you know, solar in general probably accounts for really roughly half of our RPS targets and you can see maybe a third of the solar is local. And so it is a big deal and it's really going to take, like I said, a portfolio approach but also, you know, pretty significant innovation, which on the next slide you'll see a really significant project down near our Port, and so this is probably one of largest -- it's absolutely the largest in Los Angeles but it's probably one of the two or three largest in the country rooftop solar installation. This kind of highlights the importance of our Feed in Tariff Program, where this facility probably doesn't use a whole lot of load but they've got a whole lot of roof space, and so this provides kind of an opportunity for us to leverage those roofs.

Moving onto energy storage. So in addition to updating our Castaic Plant in 2013, we also did a handful of really innovative projects, one on the right hand, bottom right, you will see a sketch of the fire station out in Porter Ranch where we installed solar and storage, and did a little demonstration of, you know, kind of a nano grid or micro grid pilot here. And, interestingly, there was an outage shortly after commissioning and there was no disruption in service for that fire station.

In addition to that we're looking at a number of recreation and parks facilities. And so, you know, we've got the benefit of being very closely tied to other city departments as well. And we're kind of leveraging those relationships as well. And, interestingly, a lot of rec and parks facilities are also used as emergency operation, back-up centers. They are used as cooling centers. And so there is a really big importance for us to look at those potential sites as pilot sites for additional micro grid installations.

We also -- and I'll show a picture of it in a moment -- accelerated our Beacon Battery Storage System, our 20-megawatt half-hour battery, a year early. And so on the next slide you will see a picture of that, and that's in the foreground. In the background you see our 250-megawatt Beacon Solar installation that was recently commissioned in phases over the last year or so.

And continuing on the next slide on storage, in response to Senate Bill 801 we were asked to look at the cost-effectiveness of incorporating 180 megawatts of storage and so, you know, we did that. We brought on a partner, we brought on EPRI. And we looked at the cost-effectiveness of that over -- over the years. And it looks like what we'll be targeting, and I think the more substantive plans will be to come, is a launch date of around 2021 for a project of this magnitude.

And moving on to demand response. Now you know we've got for our side we've got fairly ambitious plans for DR and it's been a little bit of challenge to roll those out, in part because we still need to launch the systems to be able to maintain and operate and control these. And actually we've learned that, and many folks who have done DR for a number of years have probably known this, that adoption is a little bit difficult when you don't have those systems to automate that, and a lot of customers are not willing to do sort of the manual demand response. And so in order to address that we have launched and created new groups to actually deploy the systems necessary to control that.

What we do have coming up in the future is a thermostat program that we're hoping to launch by next summer to help leverage the vast amount of smart thermostats that we already have in the City of Los Angeles.

And then we expect to this year, and we expect to be done by the end of this year, update our DR plans to look at not only what the outcomes are of the once-through cooling study but to look at things like year-round DR and beyond just the traditional, you know, summer season for DR.

On the next slide I'm going to touch on some of our electric vehicle targets. So we've got a five-year goal and this is not draft, this is now adopted, of nearly 150 [sic] electric vehicles in Los Angeles. And so that includes 10,000 commercial chargers in LA And City and LADWP are deploying a substantial amount of those on City property that's publicly accessible. And so this is, you know, particularly important having these goals in place because of the executive order to have 250 chargers by 2025, and so that really gets us on track to try to achieve that really ambitious goal.

And so how are we going to do that. We're actually going to try to play a role in increasing EV adoption, not just by having the infrastructure there but by also providing additional incentives beyond that. And so on the next slide you will see that we recently launched a used-car rebate of $450. And so that's -- you know, obviously has value for equity as well but can help hopefully drive EV purchases and adoption beyond what we had originally projected for the City of LA.

And so we also have the existing charge rebates, and we've had these since 2011. And we're also developing, and this kind of touches on demand response as well, developing a smart charging pilot that will look at dynamic rates and potentially the ability to call on those resources as needed.

And we also recently launched a very, very cool car-sharing program, an all-electric car-sharing program that will help in part touch on different parts of the city that don't have as much access to electric vehicles and the electric-vehicle charging. So I think those are going to be particularly important. Then of course we have our commercial rebates. And we're looking to actually extend -- or expand those availabilities by looking at things like any-time rates and things like that.

So I'm going to kind of wrap up the presentation by touching on energy efficiency. And I've got the budget numbers here, the actuals that kind of grow into the projected year. And one thing that you will kind of see is a very, very large growth from 2016 to 2017. And so that's not necessarily a change in scope, a change in budget. It's a change in our ability to actually reach those numbers. And so we went -- we've effectively doubled our ability to deploy. And part of that has to do with, you know, expanding our portfolio programs, but part of that has to do with accelerating some of the EV projects that we have in the pipeline which are on the next slide.

So our residential LED distribution, and this is just a few of our programs in our portfolio, but this program was intended to cover the city in three years, so do a third of the city every year. We've changed that to hitting, you know, all of the city in a single year.

We've got our AC Optimization Program where we actually do direct install for smart thermostats and do a little diagnostic on air conditioners. And I mentioned earlier that we hope to launch a demand response thermostat program next summer, and that will help leverage the deployment that we've already undertaken here.

And then we have a couple more programs, in particular, the partnership with the LAUSD, where we have been looking very, very closely at LAUSD, the school district in Los Angeles, and looking for opportunities there.

The last thing that I will touch on is electrification targets. And if -- yeah, stay here for just a second. Our council in February asked us to go back and look at electrification targets, specifically for GHG reduction, not necessarily for, you know, rate increase, but for GHG reduction. So that's something that we will be doing.

One of the efforts that we have undertaken recently as a partnership with SCE and SMUD on looking at opportunities particularly in the residential sector, and so that will be one of maybe a few different efforts that we undertake in the coming year to help address that request by our council.

And so with that I will be happy to answer any of the questions on anything that I've covered. Thank you.

CPUC COMMISSIONER RANDOLPH: What's your timing on the electrification study with Edison and SMUD?

MR. RONDOU: I don't know. I seem to remember it being near term, but I'd have to go back and check. I want to say that it's probably this calendar year, but I'm not certain.

CPUC COMMISSIONER RANDOLPH: Okay. And then I was also wondering if you could just share a little more detail about your local solar programs and how you pull disadvantaged communities into those programs.

MR. RONDOU: Yeah. Yeah, thank you for asking. I'd love to actually talk a little bit about that, so. So I have mentioned that we've got our portfolio programs. We have what's called our Solar Incentive Program and that's our program as part of the California Solar Initiative. And so that actually was scheduled to end in 2016. We elected to continue that. We had existing funding available, still in that program, but what we did is we tweaked it a little bit.

We have the limitation of where we can't identify disadvantaged communities or Zip codes that might have, you know, a higher concentration of disadvantaged communities or specify that customers on low-income rates would get a higher incentive, but what we can do is look at it from a grid-needs perspective. And we looked at Zip codes and areas of the city that have historically lower solar adoption and we made the case that there is a grid benefit of having a more even distribution of solar in our distribution grid.

Now we all know that that's not -- you know, there is a little bit of nuance to it than that. Different parts might be able to accept a little bit more or less, but in the grand scheme of things there is a grid benefit to a more even distribution. And so we used the rationale to have differentiated incentives. And so what we found is the Zip codes that were scheduled to have those differentiated incentives had a very, very significant correlation to disadvantaged communities as defined by the state of California.

And so while we are limited in many ways for targeted programs, we are able to look at, you know, what were the results of programs that benefitted sort of the wealthier and middle class customers and how could we address that from a grid-needs perspective. We used the same sort of rationale with our community solar, what we call our Rooftops Program, and that's where we do a direct install. We own that asset, you know, we receive all the energy from that asset, we provide a customer with an annual payment for the ability for us to lease that rooftop.

And then, finally, we have what we call our Shared Solar Program which will be deploying local and large-scale renewable --

solar renewable projects and allow customers to subscribe to what we're calling blocks of energy. It's just 50 kilowatt hour blocks of energy. And we run into the same challenge there where we can't explicitly target towards low-income rate customers or disadvantaged communities, but what we can do is we can say, you know, we've got portfolio programs that have allowed single-family homes to go solar for a real long time with our Solar Incentive Program that's been around in various forms since 1999, to our Rooftops Program that we just recently launched last year, so those single-family homes have that opportunity already. So what we've been able to do is provide exclusivity for multi-family for our Shared Solar Program. And then we'd like to take that one step further by being very, very aggressive and seeking outside funding to allow us to buy down that subscription rate for low-income customers. If we were able to receive outside funding, that would unlock a little bit of opportunity for us to target certain customer bases as well.

CEC CHAIR WEISENMILLER: I first wanted to thank LADWP for adjusting its transmission upgrade schedule last winter. We would like to get to the point that we're not dealing just with our luck and weather. But you know we're certainly not there yet and it's probably going to be worse this year.

But one of the things I really wanted to encourage LADWP was to help us build in your plans, and obviously we'll try to work around them, and again there may be times we, you know, say, gee, we just need another month here, or something, so share. But that's going to require flexibility I think on all of our parts going forward, as the courts would -- but I mean I understand it's very important for you to really deal with the transmission upgrades. It's got to be winter and winter is the peak time for gas, so.

MR. RONDOU: Right.

CEC CHAIR WEISENMILLER: At any rate, we'll certainly work through that.

Andrew asked me to really thank you for your push on demand response and on energy efficiency, again realizing that there is a lot -- you know everyone sort of looks at demand response as pretty easy and lots of it. And we have been finding it a real struggle to get any of it. You know, it's just sort of like every megawatt we sort of have to really push every needle we can to get there. So certainly encourage you in trying to understand how we can help or what's working for you that might help us.

What percentage of your customers are in DACs, do you know?

MR. RONDOU: You know; I don't know that answer.

CEC CHAIR WEISENMILLER: You know Edison is like 43 percent. That's a really high -- a higher number than I would have guessed, so I'm assuming you have, again, a relatively high number here too.

MR. RONDOU: Yeah. I wouldn't be surprised if we were in that ballpark or even beyond that, but, you know, I'm sorry, I don't have that here, yeah.

CEC CHAIR WEISENMILLER: That's fine. Yeah, if I could submit it later go ahead --

MR. RONDOU: Yeah.

CEC CHAIR WEISENMILLER: -- and that would be good.

The one thing I was going to encourage you to think of, you know, you have a very aggressive, as you should, ZEV Program. And that's a key part moving forward. We've talked a lot or people talk a lot about how a vehicle good can help us on the grid side. And the reality is on two-way it's like a one project in California is like 44 vehicles, so it's not exactly awesome, but it's like 44 times more than anyone else's. So it would be good to actually get some experience of a vehicle to grid, you know, particularly if you could do it in terms of your own facilities, right, your own vehicles, either work crews or trucks, or whatever, to really see how to make that wheel on just not a hypothetical, because this is going to be very important as you look at a hundred percent renewable and other stuff.

CPUC COMMISSIONER RANDOLPH: I absolutely agree with you. And from what I understand, I don't have the details we did have some pilot project that we did, but we didn't do anything with the pilot. So dust that back off and look at what we can do to look at vehicle to grid and how we can leverage the storage from both.

CEC CHAIR WEISENMILLER: I think they're both one -- I think both one way and two way. But, as I said, it's just an amazing capacity of two-way information.

MR. RONDOU: Yeah. And, to add to -- sorry, to add to that, you know we -- I kind of sprinted through it, but we do have a pilot for managed charging. So while that's not vehicle-to-grid, you know you get some of that same dynamic capability.

MR. TISOPULOS: You have an impressive energy efficiency gain, 10.4 percent through 10 of 2017, and it looks like you are trying to get up to 15.1 percent within the next three years. How realistic is it?

And the second question is: Are you seeing any commensurate benefits to the demand curve or other offsetting parameters that kind of offset that gain?

MR. RONDOU: Yeah. So the first part was, you know, is this really achievable. I think that if you asked the question a year ago, it probably would have looked a lot more challenging. But you've seen just, you know, from year 2015-16 to '16-17 a pretty substantial jump. And so, you know, given that we've got sort of the infrastructure of the teams, the trade partners, and all that in place and we've got a whole lot of momentum there, I think that they are probably achievable, but I don't want to understate how difficult and challenging that will be. And, as you can imagine, you know there's diminished returns. As we go beyond 15 it's going to be more challenging, so we're going to have to be creative.

The second part of your question was, you know, was that meant for a demand curve. And I don't know that answer, but I can tell you that there has been some talk between our integrated planning -- Integrated Resource Planning Team and our EE Team, asking them to look at more evening-focused energy efficiency.

So I don't have the answer on the impacts, but I can tell you that there is going to be a little bit of a refresh on how can we, you know, going forward further target the later peak rather than just kilowatt hours.

CEC CHAIR WEISENMILLER: So we ran a little late this morning. At least as of -- so far we have not heard from any legislative officials. So let's come back at one o'clock, a basic morning, as we're going to really start at 1:00. But, you know, try to make up, at least have some catch-up over lunch.

(Luncheon recess taken from 12:01 to 1:03 p.m.)

MR. BOHAN: Thank you, Chair.

Good afternoon, everyone. Again, I'm Drew Bohan, Executive Director of the California Energy Commission. And the panel we have assembled for you this afternoon is to discuss the Fifth Risk Assessment since the 2015 leak of natural gas at Aliso Canyon.

The assessment you're going to hear about in some detail was prepared by the Aliso Canyon Technical Assessment Group, which is comprised of staff of each of the agencies assembled here before you, the Energy Commission, Public Utilities Commission, the California Independent System Operator, and LADWP. Also Southern California Gas Company contributed hydraulic modeling to our analysis. And I will let each of my colleagues as they come up in sequence from your right to left introduce themselves.

We've got about 30 slides. We're get on have to move quickly, about a minute and a half a slide, but we invite you, since we're going to be slowly to interrupt as we go along. There is a lot of stuff packed into this presentation. And I want to just start by giving you an overview. But we're going to bounce around a little bit between presenters as we go forward.

So the purpose of this Fifth Assessment is to do two things primarily. First is to address the risk to electricity reliability given the multiple outages in the natural gas system entering the basin. The second purpose is to identify and discuss mitigation measures we can employ to try to reduce that risk.

Long-term operational issues are being handled in other forums. So specifically we won't be getting into these today in any detail, but we are looking at the feasibility of minimizing or altogether eliminating the use of Aliso Canyon storage. We are following through on a plan to phase out Aliso Canyon within ten years, as requested by Governor Brown, and other recommendations such as the Energy Commission and CPUC joint request for a moratorium on commercial and industrial natural-gas hookups in the LA area that are served by Aliso Canyon.

So the way we have structured this analysis is to look at the risk to electricity reliability in a situation that is a 1-in-10, a summer-peak day. So we may hit one this summer, we may not, but we're planning as though we will, and all the numbers you will see are calculated on that basis.

We are looking at also at the minimum generation required to keep the system running in the basin. You will hear a lot of us referring to min gen. That's what that refers to. It's not a target, it's not a goal. In fact, we really want to avoid it, but it is a number that planners can use and regulators can use as a target to make sure we keep energy -- electricity production above that level.

The full summer assessment, for you on the dias and anyone in the audience who are listening, is posted on the link you see up there at the bottom of slide 2. And we're asking the public comments be submitted to us by May 22nd so we can take those comments, we look at them all, take them all seriously, and evaluate them and then be able to respond appropriately.

Push to the next slide here.

The assessment you're going to hear about today covers multiple topics related to energy reliability in Southern California. You've heard about others earlier in the day. A few of the ones we want to highlight for you this afternoon are: First, a status report on the Southern California gas system and the pipeline outages we have been experiencing and the success we have had in remediating those. We also want to look at how we manage to largely avoid gas curtailments this past winter with a preliminary analysis of the one curtailment event that did occur between February 19th and March 6th of this year. There was a significant cold event in Southern California and the Aliso Canyon storage facility was used for 5 of those 14 days during which the curtailment took place.

We're also going to highlight the hydraulic modeling cases. So we looked at different cases that contemplate different amounts of gas being available in the system, and we want to go through that, again looking at what more or less gas means in a 1-in-10 type peak situation we might be facing.

We also want to preview gas balances into December, being able to look at how summer decisions might affect storage inventory levels in the coming winter. And what we do in the summer, particularly in the late summer in terms of whether we're going to fill up storage or utilize the gas that's in storage will have a big impact then in the winter season. So this report's focused really on summer, but we are also looking at as we get towards winter.

And then, finally, we're going to go over some potential additional mitigation measures in addition to the ones we've employed in the last few years and look at how those in the last few years have performed.

This slide view is really busy, and we're not going to walk through. We put it up front there because this has really the main numbers that you're going to hear about throughout the presentation, so I want to call your attention just to a couple of them. So if you look at the very top line, the upper left number, 3,511, that's 3511 million cubic feet a day -- or 3.5 billion cubic feet a day, that is the demand associated with the 1-in-10 peak day. That's how much gas we're going to need to avoid having to go to min gen on a peak day.

If you drop down -- one, two, three -- four lines you see 3,555. That is the amount of gas that the system can supply. So in that simple case of a 1-in-10, we've got, if you look at the very next line, 44 million cubic feet a day of gas above which we need to satisfy demand. So again 3511 at the top, 3555 several lines down, and the delta between those is 44. So in that simple situation, we're okay.

These two columns, however, represent two different situations. The first that we've been focusing on just now is the base case and the second is a sensitivity analysis where we contemplate additional outages on the natural gas system. There I might go through a couple numbers just to match what we talked about or I just mentioned on the base case. So, again, the demand is going to be the same. At a peak 1-in-10 day the demand is 3,511 million cubic feet per day.

If you then drop down several lines, you get to 3425. That's the amount of gas that would be available to the system on that day. And the very next number in red is minus 85. It's rounded it could be minus 85 or minus 86. So in that situation we're actually looking at being below, having insufficient gas to support the demand within the basin.

The line below that is the last one I want to touch on. And the left-hand column is 441 and the right is 311. What that represents is if we drop down to min gen, so this is standard operating conditions, what I talked about to this point, if we then have to drop the system down to min gen, and you'll hear from others about the negative consequences of having to do that, but if we do that we end up being in a position where we're still able to satisfy electricity demand in the basin.

However, you note the footnote at the bottom, this is all contemplating two things: One, no Aliso; but, two, it's contemplating that we're getting all the transmission of electricity into the basin that we need. And if that drops from a hundred percent to something lower, the footnote suggests there with the asterisk that if we get below 90, somewhere between 85 to 90 percent of the electricity imports to make up for the shortfall in production within the basin, then we get into a problem where even with the min gen situation, we don't have resources to satisfy demand in the basin. So that's just an overview of those numbers. Again, you will hear a lot more about those in the presentation, but the just a quick overview. Okay.

MR. RANDOLPH: And I will take it from here. Thank you, Drew.

I'm Edward Randolph, Director of the Energy Division at the California Public Utilities Commission. In starting out in my part of the presentation, I wanted to start out setting the stage a little bit. It's been a couple years since the leak at Aliso and going through these technical assessments for the summer and the winter. And, quite frankly, it seems like every time we go around, the reliability issue is either staying the same or seemingly getting a little bit more concerning out there, and why is that.

You know there's two parts to it. There's what's in the storage. The other part of running of the system is the pipelines in bringing gas into California. Since last year there have been a number of issues with the actual bulk transmission system for the natural gas system. Starting in October of last year, Line 235-2 ruptured. And that rupture also started a fire that also burned a section of Line 4000, so two major pipelines bringing gas into California.

The rupture led to new concerns about Line 4000, so SoCalGas initially took the line out of service completely and then returned it to partial service at reduced pressure in December. That pipeline still continues to operate at that reduced pressure while they, SoCalGas conducts what's pigging, inspections of the pipeline and pipeline integrity there. There is no estimated date at this point for the return of service to 235-2 while they continue to -- or, you know, while they are doing the root cause analysis on that. Well, obviously ultimately need to repair the ruptured part.

Line 3000 -- I will have a map on the next slide that shows where all these are -- is also out of service and Line 2000 is at reduced capacity. On each of these there has either been no listed return date for the pipelines on Envoy, on the public website that lets folks know what are going on on the pipelines, or for one that have had return dates. They have been pushed out repeatedly on the expected return dates.

Here is a map, it's a little small, detail in here where all the lines are. Do I have a laser that works? No. It shows where the lines are. If you follow the -- there is a blue purplish line up there that almost seemingly divides Northern California from Southern California, if you go a little bit below that, the two red lines that run initial -- well, below that, once you get a little bit west, those are Line 235 and Line 4000 coming in. Going out towards the Arizona border, you will see Line 4000 which is one of the lines out of service. And then if you go down into further south, you will see where Line 2000 is on that map. So that gives you some context where each one of those major pipelines are bringing gas into service and their reduced service.

For these pipelines coming in, the reduced service you know impacts and reduces potential inflow to both the Northern Zone and into the Southern system, so impacting both areas of the state.

So with -- you know, starting with the outage at Aliso but then continuing with some of these additional outages there has been an extremely high level of interagency cooperation to mitigate these measures and manage demand. That includes planning for OFOs which were frequently used last year. OFOs are Operational Flow Orders. Those are instances where the noncore customers, when those are put into place, are required to much more closely balance their actual demand, their actual use in the region with what they bring in there. Increased notices, watches, and alerts when necessary to the users. And all of this up until February of last year led to only two days, or resulted in only two days of having to curtail electric generation in order to help balance the gas system out there.

And then, you know, lastly in there, in the work between all the agencies there is this constant monitoring and work between SoCalGas, the ISO, and LADWP to shift generation and use imports. So, again, this is focused on that, reducing the electric demand which has the -- you know in summertime has the biggest impact on the gas demand out there.

And then I think, Katie, it's over to you.

MS. ELDER: Alrighty.

MR. RANDOLPH: Yeah.

MS. ELDER: I got the button pushed and there we go, all right. So I'm Catherine Elder with Aspen Environmental Group. I am privileged to get to work with the staff at the Energy Commission and have been working with them on these issues for a couple of years now.

We wanted to share with you what demand actually looked like for the past two summers. And this graph is actually in our report. There is also a graph in our report that will show you what the past three winters have looked like as well.

What we wanted to emphasize, how really -- how demand over the last two years that we have been able to avoid significant problems arising out of our situation with Aliso has been because demand has been lower than really it was expected to be. We show the red line is about 3.2 BcF, or 3200 MMcf. That's our stress threshold, where we get worried about the system and start calling each other and saying what are you seeing, what are you seeing, how do we fix this, how do we fix that, how are we going to make it through or not. Those calls really happen.

And you can see that for these last two summers, both 2016 and 2017, there aren't very many days that go above that red threshold. There are more in 2017 than there were in 2016, though, and we wanted to draw that to your attention.

We also drew in the blue line, which is hard to see on the screen here because of the way the screen is -- the screens are pasted together up there, but up here where it says 2016 supported demand, I'm trying to point at it -- there we go -- it's not working when I point to the screen, never mind.

That should say 2017. That's a typo and that's entirely my doing so I apologize for that. But there is a blue line right across there at 3638 MMcf, and that's our supported demand figure that came out of the hydraulic modeling.

If you wanted to compare those demand to forecast demand for a month in a normal year, 2578 MMcf per day is about the average day forecast for September, and 2420 is the average day forecast for August. So you can see how many days exceed those levels and how many days are below those levels.

Now I've got to hit the other button because this button doesn't work. There we go.

Now things changed. We got through the winter -- I should back up for a moment. As we begin to think about a winter assessment, we thought there's not very much to say. And we were actually very close to being done with our winter assessment when October 1st rolled around and Line 235-2 ruptured. And that caused us to go back and rerun the numbers and think about what the implications of that were. And in late November we were able to put out a supplemental assessment that estimated or told people that we thought that there were going to be significant gas curtailments in December and January in order to try to preserve inventory to protect core customers from an extreme peak day event that could occur in late December, usually December or in January is the typical timing of that.

So we really thought -- if I had had 20 bucks and I had to bet I would have bet that there would be curtailments in December and January, no question about it, but that didn't happen. And the reason that didn't happen is what you see in the little table over there on the right which depicts the number of days in each of the past three winters that demand was over 3.2 BcF, which again was our stress threshold, and the number of days that it was over 4 BcF. And what you can see is that winter 2017 only had 14 stress days and zero days above 4 BcF. So we really lucked out with the weather in January -- in December and January.

That changed President's Day weekend. And that weekend some cold weather started that was really much more akin to the kind of cold that we would have expected around the holiday period, the January 1st Christmas holiday period, rather. And that kind of cold resulted in demands, the days of demand were above the 3.2 BcF in the winter of 2017. Not all but most of those days were during that period, that 14-day period in February and March, going into March.

SoCalGas called the ISO and LADWP and asked them to reduce their gas burn. That amounts to a curtailment. That is a curtailment of gas service to electric generators. They were able to replace that generation by bringing in and importing more electricity and by shifting generation to plants that were not served by SoCalGas. There is a cost to that, and later on we'll see more about that.

During six days, or five days, I'm not sure now if it's five or six, there were a few hours on that many days where SoCalGas also had to withdraw gas from Aliso. So what's significant here is where we had been thinking that Aliso, withdrawing from Aliso would prevent us having to curtail the powerplants, in fact we had to do both, SoCalGas had to do both. They withdrew gas from Aliso and curtailed the powerplants during that cold spell, during that cold period.

During that period, about 10 BcF was withdrawn from storage, and you can see that now on the right-hand side in that little storage inventory table. We had inventory of about 64 BcF on January 1st, which none of us expected that we would have on January 1st, I might add. And on February 18th we still had most of it. We had 57.4 still in the ground.

Then that cold period hits and we take out 10 BcF. Now

10 BcF, all else equal, wouldn't be that concerning but for the fact that most of that, because some of that gas is at Aliso where we're using it as an asset of last resort, that causes changes to which gas gets withdrawn when. And as the inventory drops, 10 BcF is enough of a change in the inventory to change the amount that we can withdraw on any given day. And so that began to be of concern.

I should tell you that there is a similar graph to the graph I had on the prior page. We have that in the report with the winter data. It's at page 10 of the detailed report. Figure 2 will show you that.

And the only thing I wanted to add to that was that would all be irrelevant if we didn't have the pipeline outages.

I'm going to turn this back to Ed.

MR. RANDOLPH: Thank you, Katie.

Yeah, so as Katie mentioned during that cold snap there were several days where they had to withdraw gas out of Aliso while at the same time they were curtailing gas to electric generators. You know, again since the original leak at Aliso Canyon and the protocol put in place on how to use Aliso, there have only been six days in which gas was withdrawn from Aliso, four of them during that cold spell at the end of February, going into March there.

We have started -- joint agencies have started a process of analyzing how the system was operated during that cold snap to look to, A, ensure that SoCalGas did operate the system consistent with withdrawal protocols, but also to glean any lessons learned on ways to improve operation of the system going forward. That is ongoing and will -- because it will more affect the next winter assessment, you know, we will focus on getting the summer assessment done first. However, there are some preliminary results that we've seen in there.

Key in there is that the preliminary review shows that system receipts were consistently less than system demand. that's both on a daily and an hourly basis. The public can see on the websites the daily flows. The hourly flows are confidential, and we often try to explain to folks that because you're managing for a peak few hours in the day, the daily flows may not show the full picture. But we have seen and are concerned that at no time was the system operated to its full capacity under the analysis we have seen so far.

There are zero hours in which to receive point capacity, and so gas system was fully utilized. Yeah, and again as I said, we'll have a more detailed report coming out later in the year.

And, additionally, LADWP and the ISO are both assessing the cost impact on electric users. And the CPUC report updates will take this into account as we do the winter -- look at winter -- you know, sorry. I phrased that poorly. But we will look in this as we look at the technical assessments for winter 2018-19 and any needed revisions to the 715 report and to withdrawal protocols.

I just mention that the two balancing authorities, LADWP and CalISO, are doing some analysis on price impacts on electric generation. We have done what is somewhat of a rough impact on prices on gas. And, you know, this chart shows that as a comparison if you look at the bottom two lines on this -- I see the key to this has somehow dropped off the slide, but the bottom two lines to this show what -- oh, they're on the top there -- what are PG&E's Citygate price, so prices paid for wholesale gas into the PG&E service territory. That's the blue line.

The red line is prices paid at the SoCal border. And then that green line is the Citygate price for SoCalGas. So what is paid wholesale for both core and noncore customers on those days, coming into that restricted region within SoCalGas's service territory. And you can see that despite the fact that that cold spell was fairly statewide, in demand for natural gas, and Northern California also went up fairly significantly in those days, the PG&E and the noncore customers in Northern California were able to manage gas supplies by withdrawing from storage to mitigate against any increases at the Citygate and then also consequently keep those prices low relative to Southern California that was almost exclusively dependent on that gas coming in, and the limited ability to bring it in did significantly increase prices.

And then now, Katie, it's back to you.

MS. ELDER: Okay. So we're going to go into some more detail now. And two pages later I'm going to torture you with rows that have lots of numbers. So bear with me.

Overall we do have a little bit of good news that we're very pleased to be able to share, and that's that the gas requirement when the powerplants go to min gen if they have to go to min gen on a 1-in-10 peak day, electricity peak day I should say, that is actually lower this year than it was last year. So that's good news.

And if everything else had been -- had remained equal, we'd probably not be having a workshop today. We'd just have happy news that we were in better shape than we were a year ago, but that's not true. and the bad news is that we've got these pipeline outages and we're going to talk a little bit more in a minute about the magnitude of what that does to our operating capacity and ability to serve demand.

There are some physical system mitigation measures that SoCalGas can apply to those pipeline outages. And they -- around -- there's a lot of uncertainty around which of those will actually work and how much they will get us. So that's sort of bad news.

And the end result is that the supported demand, in other words, the level of demand that the SoCalGas system, using its pipeline capacity and its storage, is lower this year than it was last year. So that's also a bad outcome.

The end result is that we think that they will have to use storage more frequently to meet that supported demand number. There are more hours in which they will have to pull gas from storage in order to achieve the estimated supported demand bubble.

As Drew mentioned earlier in the summary piece, it's not possible to meet the 1-in-10 electricity peak day on an N-1 -- with an N-1 contingency event without using gas from storage. You absolutely have to use gas from storage in order to achieve that level of demand.

There are some sensitivity cases with more outages, including sensitivity on the electricity side where we don't think we would have enough gas to even meet all of the min gen at an N-1 level, and those cases are plausible. Those cases could actually occur. We think that SoCalGas is likely to have to call operational flow orders more often than last summer because of the supported demand issue and because they will have to use gas from storage more frequently, and that having to use gas from storage more frequently puts the filling of gas for storage for winter in jeopardy. It's not a case in certainty about what the actual inventory is that would be achieved going into the winter.

And I can't hit the right button, so Ed is going to hit the button for me because I may be a racecar driver, but I can't operate the equipment, so there you go.

The outages really have significantly impaired SoCalGas's system. There is somewhere between 255 and 860 a day out of service versus last summer. And that -- and I say we have given that range because it depends on exactly which outages stay in place and it depends on which physical mitigation, system mitigation steps actually work. And I'm going to go into more detail about those in just the next page.

As I mentioned, that reduces supported demand. And in the base case, supported demand is 83 a day MMcf per day lower than it was last summer. In the sensitivity case, it's 213 MMcf per day lower, and that's despite min gen being lower by almost 300 MMcf per day. So there you can see why if all else had remained the same but min gen had dropped, we'd be in better shape.

Overall there is about half a BcF per day, or 500 MMcf per day, of pipeline capacity that's missing, depending on which case we're looking at. And we can be better off around that number, depending on which of the system mitigation measures work and which of these additional -- potential additional outages come to fruition, and what gets fixed on the system.

So we could go to the -- yeah, the first of this awful page with all the numbers.

I promised to walk you through sort of the range, what I keep talking about this range of how much pipeline capacity is available. And what we've shown here on this slide is where we were last summer in terms of available pipeline capacity. And there was a total of 3185 MMcf per day and you see that over on the lower left and it's in red, to highlight it for you. So that's what we had last year. And then supported demand was higher than that because supported demand included pulling some gas from storage. That's essentially the difference between pipeline capacity and supported demand. It's how much gas you used from storage.

As of May 1st, the pipeline capacity that we had available or SoCalGas had available was 2.65 BcF per day or 2655 MMcf per day.

So you can see that's about 500 a day lower than we were last summer.

We have a case for this summer where Lana Wong and I got very pessimistic and we got down to 2325 MMcf per day. And the issue there is what was really -- was Line 4000 come back or not or does Line 4000 go away or not, rather I should say, and what happens at Kramer Junction and what happens at Otay Mesa. Those are really the three big variables here. North Needles, Kramer, and Otay Mesa. And those are the key differences as you look across the columns on these slides.

On a more optimistic case where we saw Line 4000 staying available, where we got more gas at Kramer Junction and we got some gas delivered at Otay Mesa, a certain of 230 day there, we got up to 2930 MMcf per day. And that case made us a little bit happier, shall I say.

We settled on a combined case where we have Line 4000 going out, we've got some additional gas at Kramer, we've got some additional gas at Otay Mesa, but we have a reduction on the line that comes in from Ehrenberg and Blythe, and that gets us down to 2480 MMcf per day. So that gives you a sense of how we constructed these ranges and what the key variables are on the system.

Next slide. So we asked SoCalGas, having these in mind, and these do translate later into some gas balance scenarios that we'll talk about in a bit, we asked SoCalGas to run two hydraulic scenarios for us. They also did a couple of hydraulic scenarios. The differences between what they have done and with we have done go to exactly which capacity goes out and which mitigations work. SoCalGas also discounts their pipeline capacity by 15 percent, and we were not showing that discount so that you can get a sense of what the full system should be able to do. And we have to have a mitigation measure trying to make sure that the whole system gets used.

Here you can see where we were, again the left-hand two columns showing you where we were last summer. And you can see our supported demand in red near the bottom, 3638 MMcf per day. The base case assumptions, we have listed all of the assumptions for both our base case, what we call our base case, and the sensitivity case, give you a supported demand of 3555 MMcf per day, and in the sensitivity case 3425 MMcf per day. And that's how capacity -- this just gives you a sense or shows you how pipeline capacity translates into a supported demand.

There is a row -- and I'm trying to eyeball it and I'm not seeing it, which means that I'm going to cover it in a different slide. Ha-ha. It's on the next one.

I mentioned that this supported demand number versus the pipeline capacity is a difference as to how much gas gets used from storage. And this page is intended to draw that out and demonstrate that for you, make it easier to see. I mean, in essence, any time demand is higher than pipeline capacity you've got to use gas from storage. That's the only way you're going to serve that demand.

Last summer the hydraulic analysis shows using 468 MMcf per day from storage. This summer it uses 900 a day MMcf per day from storage. It's not because the concept of the storage is different. It's really that this summer the hydraulic analysis has to use the gas from storage in more hours of the day than it did last year. So it's pulling it out, I believe, at the same rate as last summer, but doing that for more hours gives you the 900 instead of the 468 MMcf per day. So this is how the way in which SoCalGas ends up having to use more gas from storage to achieve that supported demand level and that of course gives us worries about the field inventories, what's actually achievable, how many high-demand days do you have. I know we showed you the slide earlier that showed you exactly how many high-demand days we had last summer and how many high-demand days we had the previous summer, so you get that sense of luck about the weather.

And this also leads us to worry more about, as I've mentioned before, more OFOs, both high and low, trying to keep in balance while we use this amount of storage.

And with that, I'm going to turn to Dennis.

MR. PETERS: Hey. Good afternoon. Dennis Peters with the California ISO. And I'm going to cover the next two slides here.

This first one we're going to go into a little bit of detail about the minimum generation requirement that everyone's been talking about. So, essentially, the ISO and LADWP, as the two relevant BAs for the greater LA area in Southern California, work together to update our analysis to determine how much natural gas the powerplants would need to maintain system reliability under both normal and unexpected contingency conditions. So this calculated minimum gas burn of 1574 million cubic feet per day, it's significantly lower than what would be required under normal conditions. So under a 1-in-10 electric peak, the requirement is about 400 million cubic feet more, or about 1971 million cubic feet per day.

And I think the important thing to note here when we're talking about this minimum generation is that we don't calculate this to with a plan for SoCalGas to curtail electric generation but rather it's so that SoCalGas, we as the BAs, the balancing authorities of LA, LADWP, and ISO, as well as regulatory agencies, can have -- to know how large of a cut and the system can sustain before electric reliability is jeopardized. So the implied reduction in gas from normal to minimum generation levels is effectively a curtailment of gas service to electric generations.

So how do we do that, how do we get down to a minimum generation when electric generation is curtailed. So, first, moving to min gen is not easy or desirable. You know it means shifting generation to less desirable and less economic sources. And it's done a little bit differently for the ISO versus LADWP. For the ISO, since we do have other units outside of the Los Angeles area, the LA Basin, we can shift to those other generating units by using -- putting a constraint in our market. For LADWP, since they are limited to the powerplants within their balancing authority, they're required to then go to external sources for imports.

So we didn't in this analysis get into any of the financial or environmental impacts of operating electric generation in these nonefficient, noneconomic ways. But certainly there is an impact to the cost of electricity, and we didn't attempt to quantify it in this analysis.

So in terms of achieving this minimum gas burn, so since most of the replacement energy would have to be imported into the area, either for the ISO from powerplants outside the LA Basin or for LADWP looking for imports from other entities, you know we're limited then by a couple of things. So the electric transmission lines. There is an assumption in the study that they're all operating, all lines and service, with a hundred percent of the potential capacity for import utilization. Also an assumption that any replacement units outside of the SoCalGas area would have access to gas as well.

So the calculation. As I mentioned, LADWP and the ISO did this analysis. Some of the key assumptions in that analysis, to just touch on what we assumed with regard to load forecast, with regards to imports into Southern California, as well as outages that we considered. So, first, the load forecast in the analysis, we assumed a 1-in-10 peak summer demand for Southern California Edison, for San Diego Gas & Electric, and LADWP. For the imports into Southern California, and this is important, and I will get into more details about the analysis at different levels, but we assumed a hundred percent of the total available transmission capacity in this analysis. So that was over 18,000 megawatts of import capability, and that is higher than the approximate 15,000 megawatts that we've ever seen historically as imports into Southern California. And that's important. I will get into that more in the next slide.

With regard to outages. So where our analysis reflects an N-1 contingency event that results in a combined loss of about 2837 megawatts for LADWP and the ISO. That's essentially the loss of the Pacific DC Intertie.

So then we get to the results here. So the 1574 is actually two components. As I mentioned, that we did the analysis to look at both normal and what the required burn would be under an unexpected contingency event, this N-1. In the normal gas burn, that's what we need to support reliability under normal conditions. That's 1446 million cubic feet per day. We just want to mention that it also includes all the gas required by QFs, which account for about ten percent of that minimum burn. And that sort of splits into 313 million cubic feet per day for LADWP, 1133 for the ISO.

The minimum burn for LADWP went up slightly since last year, primarily due to increase in load over last year. For the ISO, our numbers went down probably about 300 million cubic feet per day. And that's primarily due to two things. One is some of the transmission upgrades that we'll talk about later in the presentation that have improved the ability to import into the area; as well as the way we did the analysis, we considered -- we used emergency ratings for the lines in the analysis this year versus last year.

So then the second part of the analysis was then how much gas we needed to recover from this N-1 contingency and that being the loss of the Pacific DC Intertie, and that equates to approximately 128 million cubic feet per day. So if you take the normal 1446, normal operations, plus the 128 for the contingency, you end up with this 1574 million cubic feet per day minimum gen requirement.

And I will go to the next slide. So we'll talk a little bit here about how we meet the 1-in-10 demand when we reduce down to minimum generation. So we already said that the supported demand is lower in terms of the gas system, but then electric gen minimum generation is also lower.

So of course the consequence of going to min gen, we already talked about that, is it results in increased costs to serve electric load. And we have these assumptions that it's only feasible when we actually have external supplies available and a hundred percent of the electric transmission is available and used.

So we look at this table here, and I think Drew covered a little bit of this so we won't go into a lot of detail, but essentially in both the base case and sensitivity, the gas system supported demand without using Aliso Canyon is, you know, sufficient if the powerplants are cut to minimum generation levels. So in the base case, you can see down at the bottom that supported demand shows 441 million cubic feet per day still available in the gas system after we move to minimum generation. In the sensitivity case, that surplus is smaller, at 311 million cubic feet per day.

So then, if you recall, I said that the study we did that resulted in these numbers and what the minimum gen would be was based upon a hundred percent import utilization. So if we start to look then at, you know, more realistic levels of transmission imports, we look at, for example, 90 percent utilization, which is about 16,-, almost 17,000 megawatts import, down from the 18,000 available capacity, that surplus of 311 in the sensitivity case then shrinks to just a surplus of 34 million cubic feet per day.

If we go down to an 85-percent transmission capacity utilization, then we are actually in a deficit of 67 million cubic feet per day. So you can see we can't meet this 1-in-10 demand, but there are a lot of ifs in this equation and there is actually a cost too.

So, with that, I'm going to turn it back over to Katie.

MS. ELDER: Me, yeah.

MR. ROTHLEDER: Dennis, if you could, -- this is Mark Rothleder -- if you got into the deficit, what are the options at that point? What would occur?

MR. PETERS: Yeah. So if the resupply options had been exhausted and you would need potentially to get additional gas from other sources, including Aliso Canyon, or electric load shed would be required.

MS. ELDER: So if we're ready we can go to the next -- oh, there it is. Thank you.

We did -- we prepared a number, I mean seven, a number of different gas balance simulation cases. We were trying to get a handle on what kind of storage inventory we might be looking at for next winter, having come through this past winter relatively unscathed but recognizing that it was, you know, white knuckle for a good part of the winter, both going into December, when we were just certain that we were going to have problems in late December-January; and then white knuckles again when the cold snap occurred in late February. So we want to take a hard look at what these cases implied or what these different outage scenarios and the potential physical mitigation measures for the gas system, what those might result in.

So on this page what you see is a table with lots of numbers again, but I'm going to try to show you that they're pretty simple. We have done -- they're A through D. And Case A is current conditions. And that included our pipeline capacity of 2655 MMcf per day. And in the gas balance, when a gas balance is just taking supply versus demand and looking at what the delta is, do you have some headroom, do you have supply and capacity in excess of demand so that you can make sure you can serve all demand. That's all it is.

And the ability that it gives us or the extra ability it gives us is to look at injections for a month and withdrawals for a month and keep track of what the resulting storage inventory would be. So the tables that go behind each of these cases that are summarized on this page are in the report so that you can look at them individually.

The reserve margin in Case A turns out to range between 0 and 10 percent. In previous years where we've done this, previous gas balance analyses, I would have liked to target kind of a 15 percent reserve margin, which is that there is no real magic about 15 percent. It's just 15 percent makes me comfortable that when a peak day happens and the delta between weekend and weekday happens, that 15 percent gives room for that to happen. Fifteen percent gives you a little room for some other things to go haywire in the system and still be okay.

Remember that the demand numbers that are shown for each month in the detailed gas balances are average demand for that month. They're not an actual day, they're just averaged over the entire month. So in winter month, like a December month, they might be a little bit understated. There are other months where they might be a little bit overstated, given the typical day in that particular month. So they're an average.

So on average we ended up with reserve margins that were pretty poor, most of them relatively close to zero. And at the end of the year, we had 50 -- end of the year I mean December 31st -- we showed 54 BcF in storage.

Now just to give you a perspective, if I do a gas balance that has no outages, so we go back to a case like we would have showed you last summer, and run gas supply in and out of storage, I would have ended up with about 60 BcF or 59 BcF in storage at the end of the year. So in this particular case, we were just a little bit under where we would have been if we had all of the pipeline capacity working.

Now we're of course worried, as we told you earlier, that these current conditions on the pipeline are not going to hold, that there may be some additional outages that happen later in the summer. And so we have also looked at additional outages case, that's Case B. And before I go to that I should mention that we did an A.30, which was current conditions. We looked at could we get 30 BcF in at Aliso, because SoCalGas has requested the opportunity to increase the inventory there. We weren't sure at first if that was even achievable, so we confirmed it. And, in fact, if that were to happen, then we could get 59 BcF in by the end of the year and still have 75 during the summer and still be at 59 at the end of the year.

In Case B we added some additional outages. That gave us a pipeline capacity of 2325. There -- our reserve margins are incredibly poor. They're all between zero and two. We ended up with gas in storage at the end of December at 30 BcF, which would be much lower than what we had even beginning on February 18th of this year.

Case C looked at current conditions but with some additional mitigation measures on the system, which means basically making sure that you get 230 a day to show up Otay Mesa every day, getting some of that additional gas available at Kramer Junction, etc. And in that case we have pipeline capacity of 2930 MMcf per day. The reserve margins are actually pretty high in some months.

There are also months in which they're zero, which means you're just running by the skin of your teeth. And in that case we were able to achieve storage inventory of 75 BcF in July and we still had 67 of it in December, at the end of the year.

In Case D we looked at some additional outages and with mitigation for -- system mitigation at Otay Mesa and Kramer Junction and so forth. That gave us the storage inventory -- I'm sorry. I just said the wrong thing. That gave us pipeline capacity of 2480 MMcf per day. The reserve margins range from 0 to 11. We would only end up with 70 BcF in storage, that would happen in July, and 43 BcF at the end of the year left in storage.

Case D.30 looked at those additional outages but system mitigation but also tested going to 30 BcF at Aliso. The rough difference between those two cases is that at the end of the year in one of them you end up with 43 BcF and the other you end up with 48. That's the basic difference.

We also did a case that said, well, let's -- call D.Max, where we had the additional outages, we did some system mitigation, and then we used every single bit of pipeline capacity that was left in our balance to inject more gas in storage. We wanted to see what's the absolute maximum that we could get in there if everything worked just right. That turned out to be 96 BcF in August, and then you end up withdrawing some gas in September and October and December, and you end up at 69 BcF at the end of the year.

So that gives you a sense of the range of year-end storage inventory, and that's the column I'd really focus on there, the pipeline capacity, in that third column that says September capacity versus what we end up with in storage at the end of the year.

And, with that, I'm going to go back to Ed.

MR. RANDOLPH: All right. So what do we do? The action, the technical assessment also includes recommendations to update to the action plan. Since we started doing these technical assessments, the joint agencies have proposed action plans in each one of those.

Over time that's developed into 39 mitigation measures unaccumulated in the prior action plans. Most of those measures, the impact of those continue forward either to measure themself, continues going forward or the gas or electric savings that resulted from those measures are a permanent savings. So we see those going forward.

We're suggesting five new measures for the summer of 2018. One is get 230 million cubic feet a day for gas flow in through Otay Mesa using LNG. The second is to fully utilize pipeline capacity by allowing SoCalGas to buy gas. A little clarification on this. As the system operator, pipeline operator, SoCalGas does not directly buy gas. For the noncore customers, they buy it for their own need. And then a different wing of SoCalGas buys gas for the core customers.

In the Southern system there is a mechanism where the pipeline operator will buy gas to maintain reliability there. We're proposing to include that same mechanism in the LA region, in the

Northern system.

Third, use existing rules to call high and low OFOs more frequently in together when necessary. Four, identify and expedite pending transmission upgrades with the potential to reduce the min gen requirement. And, five, monitor status of U.S. Department of Energy natural gas demand response programs to ensure California is a region for the pilots. And I'll talk a little bit more about what California's already doing on natural gas demand response.

And then knowing that a lot of these pipeline outages may continue going forward, the joint agencies are going to continue working on the plan for next winter unless we see some dramatic change in the pipeline maintenance schedules. One slide too many.

so a little bit of report on the prior measures. As I've said, most of the prior measures that the prior action plans have done remain ongoing, either through rules that made them permanent or ones that are conservation measures. Once that conservation -- once that efficiency was put in place, it tends to stay there.

A couple I do want to highlight here that are of particular interest. You know really going down to the bottom one, develop and deploy gas demand response programs. That's checked off on the box as done. As we'll see in the next slide in a second, a lot of the savings from this is accumulated in summertime because the savings comes from managing the electric system better. When the noncore is the big gas user in the wintertime, when the core is the big gas user, it's much harder to get in and get reductions in usage more efficiently in the system with the core customers. One place we can do that is with demand response programs.

The last two winters we have had gas demand response programs in place taking advantage of smart thermostats. In both times -- based on both winters, I believe that we can dramatically expand on the effectiveness of those programs by getting an earlier start, so we have already actually directed the utility to begin planning for next winter, marketing outreach on that through an advice letter process, and have directed them to file an application with the PUC to create a more permanent, long-term demand response program.

Finally, here are some of the results. We will be posting or have posted on the PUC's website today an assessment of the effectiveness of the mitigation measures that are under the PUC's control. That's not a total of the effectiveness of all the programs because we don't have an analysis of the mitigation measures that LADWP has put in place or the efforts that CalISO has done to reduce gas need for electric generation.

As you can see from this chart, in the summertime the combination of these measures is fairly significant in its reducing of gas flow. And actually it's probably more significant than these numbers dictate because it's getting -- as we get further and further away from implementing some of these measures, somewhat ironically it gets harder and harder to measure them. Some of the energy efficiency measures in there, now that they're embedded in future forecasts, it's actually harder to pull out those individual measures to show what they're doing, so we actually think there's actually a little bit more savings than what we're estimating here. However, in the wintertime, which is where going forward we're really going to need some of the savings, they aren't as significant. And, like I said, one of the places we will already start focusing so we're thinking about it well in advance is the natural gas demand response programs.

And I think with that -- oh, sorry. And then PUC activities beyond the action plan. As I've already just mentioned, we updated the Aliso Canyon Demand Side Resource Impact Report, which is available on our website now. And then in addition to the Aliso Canyon mitigation measures, the CPUC estimates impacts of existing and authorized demand side resources that also reduce demand for natural gas in the region. That, again as I've said, there are other measures beyond Aliso Canyon that are leading to reductions on both electric and natural gas in the region that aren't incorporated in the report but are ongoing.

The California Council for Science and Technology's long-term study of statewide viability of natural gas was released this January. We will be holding a workshop on that some time in the summer around that.

And then the order instituting investigation into the feasibility of reducing or eliminating use of Aliso Canyon has been opened and, as Commissioner Randolph mentioned in her opening comments today, that is taking the long-term look at ways to reduce or eliminate the need for Aliso Canyon.

And then, finally, as this summer technical assessment is complete, my staff will begin working on an update to the 715 report and that is the report that requires the PUC to determine the maximum amount of gas that can be stored in Aliso based on what is needed for reliability purposes.

And, with that,...

MR. PETERS: Okay. So back to me. I will talk the next three slides with regard to what the ISO has done with regard to mitigation measures since 2016, giving you an update over the past year.

So, first off, much better coordination between the ISO, SoCalGas, and generators within the ISO's balancing authority since 2016. The result of that proactive coordination is that the reduction in the amount of gas in balance on a daily basis. So if you look at this graph, it's a little hard to follow. It does a calculation between what our real time dispatch is and what our day-ahead market is in terms of the million Btu. And you can see that it's reduced over time substantially, since 2015, to '16. The numbers down below, you can see through the summer months, have all reduced significantly. And that's really for two reasons. So one is the ISO since 2016, we have a new provision in our tariff -- or temporary provisions that we renew every year, that we deliver the estimated gas dispatch for the second day out in our markets to the gas generator. So a little background on the timing then.

So the ISO's day-ahead market closes at ten o'clock. Results are posted at one o'clock, so that generators to participate in the timely nomination gas cycle, timely gas nomination cycle nominations are due at eleven o'clock in the morning. So at eleven o'clock in the morning, generators only know what their previous day's gas burns were. They don't know yet what the results of that day-ahead market will be for the next day.

So on the previous day, in the afternoon of the previous day, not only do they receive their day-ahead results they also received two-day-ahead results -- a day plus two we'll call it. And what that results in is they have a better idea of what the amount of gas to nominate would be for that particular next day.

Additionally, we're also increasing gas and electric coordination with SoCalGas. SoCalGas receives from us similar information, not only the day-ahead market results but the day-plus-two market results, as well as real time data on what the gas burns are. So it helps them to improve cooperation, proactive operation of the gas system. We also hold, you know, preparation meetings for summer and winter, coordination meetings with SoCalGas.

The tariff provisions that we have in place for providing the day-plus-two information to generators are in place until December 16th of 2018 and likely would extend those then going into 2019. So the next slide, let's see. There we go.

So some of these things you heard from Neil Millar in his earlier presentation, but as far as the analysis that I talked about in previous slides, including in those power flow analyses were several new transmission upgrades that were originally put in place as a result of planning -- transmission planning processes in 2013 and '14, where we installed upgrades due to the loss of the SONGS and as well as upcoming OTC retirements. Three completed projects, at least two are in service, the Santiago Synchronous Condenser in the Edison area, and the San Luis Rey Synchronous Condenser in the SDG&E area. The upcoming Sycamore-Penasquitos, you heard about that this morning as well, we expect to see that in service by July of 2018. So the way these really help reduce the whole gas burn, minimum gas burn requirement is that it allows for increased imports into the SoCal area.

Some other projects that you also heard about this morning, so three new ones that will be in place after this summer that also allow for greater import -- imports into Southern California. The San Onofre Synchronous Condenser we expect to see in service by October of this year. The Suncrest Static VAR Compensator, sort of undetermined at this time. The service date is being revisited by the project sponsor. And of course, you know, the highlight of Neil's presentation this morning that we're all looking forward to is this looping in of 500 kV into the Mesa Substation. And that would be a significant improvement into allowing imports into the LA Basin area.

And we're back to -- oh, it's -- I'll give to Chris Lynn.

MR. LYNN: All right. Hi. I'm Chris Lynn with the LA Department of Water and Power, Director of the Power Supply Operations Division. So I'm here to talk about the mitigation measures.

And the first item is to talk about the coordination, and there has been a lot of coordination between SoCalGas, CalISO, and the LADWP. You know this improves the situational awareness, particularly during the critical high-heat days.

A couple things I want to mention is, you know, we're doing a day-ahead hourly gas burn estimate every day, and then we're talking with SoCalGas and CalISO on a daily basis. On high-heat days, we're talking to them even more often than that. So the coordination has been very well and it's helped, in particular, you know on the February 19, when we had the first cold day, within hours the three utilities were talking -- or the balancing authority, CAISO, and SoCalGas and ourselves. We're talking to one another and coming up with plans on how we could work through the curtailments that we were having for that timeframe.

The other time that I remember was the pipeline, the 235-2 went with a rupture. Once again within hours, SoCalGas was in contact with ourselves, LADWP and CAISO. And we were putting plans in place and determining what needed to be done and how we could keep reliable electricity going during that time.

So the next bullet. We have updated our physical gas hedging. There is no physical gas purchases, only financial. So we're not making any physical purchases until the day ahead, like on a spot purchase. And that's -- you know that's been giving us the ability to watch what's happening with our curtailments and curtailment watch periods. So that's been very helpful as well.

Update on economic dispatch. This provides additional operational flexibility by performing noneconomic dispatch purchases which reduce reliance on local gas by 1.7 BcF. And that was for the period of quarter 3, which is the summer months of 2017.

So the block energy and capacity sales. We haven't -- we are not making term energy sales through the summer. It's just too risky to be making sales, in particular if we're selling gas generation to utilities within our own balancing authority, and if there is a curtailment it kind of compounds the problem, so we are not making those types of purchases through the summer.

And then the next bullet. You know we continue to maintain the dual fuel capability. That's at three of our gas-generating stations. So -- but what I want to emphasize here is that is a last resort to maintain electric reliability in emergency situations. So everything else is exhausted before we would use the dual fuel capability within the LA system.

And then, finally, the last bullet. You heard the presentation about preferred resources and transmission. You know LA's done a lot with solar and bringing transmission in. We've got like a thousand megawatts coming in from the Mojave and Southern Nevada area. But even with that we're still reliant on gas in the

LA Basin. And in particular I want to mention postponing the transmission lines in the wintertime because of the capacity reductions, pretty much what it's doing is it's postponing what we're trying to do which is get off of gas and go to a more renewable portfolio.

So I think it was mentioned earlier that we need to come up with a plan on how to continue the transmission upgrades, keep moving toward the 100-percent renewable, which is what the plan is. And to do that, we really -- you know we postponed those outages on those lines because of had we moved forward with the need for gas through last winter for LA would have been five times what it actually was. So it just did not make sense to do that work with the line outages that existed.

So, with that, I can turn it over to Drew.

MR. BOHAN: It is my privilege to provide a quick summary. First I just want to thank you very much for your patience. We just spent the last hour providing you with a dizzying number of statistics and analysis.

The bottom line, though, is that the agencies at this table are going to be doing their level best over the coming months to make sure that we maintain reliability in Southern California. It's not going to be an easy task, but the collaboration has proved fruitful in the past. A couple of years, we expect to do the same coming up.

We can't control weather. We can't directly control pipeline outages, but we'll do our best to control what we can.

Three things we think are important, looking back on what you've just heard, that will help us do this. The first is we've got to fully utilize the pipeline capacity. Whatever we've got in the pipes we've got to use that. Second, we have got to make sure we do a good job of implementing all the mitigation measures that we discussed. And, third, we've got to do what we can to help facilitate those repairs on the gas lines, because the quicker those get repaired, the quicker problems we face get resolved.

The final slide is, I'm not going to walk through all these, you heard about each of these, but the -- anyway, we lost the slide. But we're -- that's right, I'll just run through them.

So the main things we're going to be looking at in terms of mitigation measures are -- he's fast -- are outages. Obviously, keep an eye on the repair work, very closely. Pipeline utilization, like I just described. Storage inventories -- she'll get to the slide.

And then finally I just want to close by saying, again, we didn't talk about it here, but I want to re-emphasize the importance of the other things that we're doing, and those include looking at the feasibility of minimizing or eliminating the use of Aliso Canyon. Second, looking at phasing out Aliso Canyon in the next ten years, as Governor Brown has requested. And, finally, looking at the potential moratorium on gas hookups in the basin, because the fewer of those we have the less demand grows.

And, again, I just want to thank you all very much for your time and attention. And we'll of course take questions.

CEC CHAIR WEISENMILLER: Thanks. I had a couple of questions. One is in the morning we heard from LADWP about their plans to upgrade their transmission system. And that work has to be done in the winter. And, at the same time looking at your slides, everything said assuming a hundred percent transmission availability, this is what things look like. And, in fact, if it gets below 85 to 90, we're in a problem.

So how do we build in the necessary transmission work, either maintenance or expansion so that we're not saying out of the box, you know, we're assuming a hundred percent transmission but we're not going to have it?

MR. LYNN: Yeah, so I can speak to that. So, yeah, so the slides are talking about the summer, so we wouldn't be --

CEC CHAIR WEISENMILLER: Right.

MR. LYNN: -- doing transmission work during the summer because that's our high-load period.

CEC CHAIR WEISENMILLER: Right.

MR. LYNN: So then, you know, our transmission work would need to happen in the wintertime or start in the fall and probably go through the winter periods. And for that to happen we're going -- we would need that pipeline capacity for the gas to be restored, because when the reality is -- you know, and you're correct. We need to take not only the transmission lines that we're working on to do the reconductor, but often that's not the only line that's in a right-of-way. So we often take multiple transmission lines out of service so that we can perform work on one of those lines. So for that to happen, we would need those pipelines available.

CEC CHAIR WEISENMILLER: Okay.

CPUC COMMISSIONER RECHTSCHAFFEN: May I ask a follow-up, Bob?

CEC CHAIR WEISENMILLER: Sure.

CPUC COMMISSIONER RECHTSCHAFFEN: So does the 18,000, the figure of 18,000 megawatts imported assume -- does it assume upgrades that you're in the process of doing or does that assume just everything is working on the system right now?

MR. PETERS: So the 18,000, 818 actually is the available transmission capacity right now of the system.

CPUC COMMISSIONER RECHTSCHAFFEN: Okay.

CEC CHAIR WEISENMILLER: So a different question. Had -- you know we're struggling a lot with pipeline capacity, where is it, how do we get it back in line. You know what regulatory tools does the PUC have to actually get stuff done fast, to get it back?

MR. RANDOLPH: That's a good question, and I don't have great answers to that right now. You know when last October, when Line 235 went out and then you had some issues with some other pipelines, that was a fairly -- you know from a regulator standpoint, that was one that you could look at and say given the totality of things we can understand why the public may be suspicious of motives or other things, but a pipeline did rupture. And the utility is going out to repair it and we do want them to be focused on safety through and through, so we do want them to do a root cause analysis on what caused the explosion. And there were some similarities in the pipelines to -- between 235 and 4000, so it makes sense to reduce pressure there and pig it. You know all of that is seemingly justified by the utility.

The regulator does have -- not my division but another division -- folks who are out in the field as part of the root cause inspection and looking at time lines there to make sure they're operating in a safe manner.

The question that we're beginning to ask -- not beginning to -- have been seriously asking now is as online dates get delayed, as more pipeline start to have issues, you know, what is really going on with their system, and is SoCalGas properly managing their system. So we are having the discussions now on what are the regulatory tools we have from a proceeding standpoint, for a standpoint of working with the other agencies out there to do that, without having the regulator become the micro manager of the utility. And it may take the regulator to become the micro manager of the utility, but that's not our skillset. So that's something that we're trying to avoid and trying to figure out the tools we have that are short of that.

CEC CHAIR WEISENMILLER: Exactly. It just seemed like at some point you have to wonder is the study useful and if it's not, take it out of rate base.

MS. KERR: I have a question about you mentioned -- you were talking about the withdrawal protocols and the procedures by which they are allowed to withdraw. What about injection protocols, do they have certain requirements they're supposed to follow in terms of injection, and how does that work?

MR. RANDOLPH: On the injection side, we both last summer and have already started this for this summer, ruled two directives to them to make sure that they are injecting gas into all of the storage facilities to get them up to the maximum capacity they possibly can. You know last year that included some, I think, specific directives on volumes to target in the other non-Aliso storage fields. So far this year we have directed them to submit a plan to us and I believe it's actually on the Commission agenda for a vote this Thursday to approve that, if not, it's the next meeting, a plan for the -- to purchase gas using the core customers to put in storage to make sure that they are injecting enough gas into the non-Aliso fields so that there is sufficient gas there next year without putting unnecessary pressure on Aliso.

CPUC COMMISSIONER RANDOLPH: Okay. And then you know we talked about pipeline outages, but we're also having a conversation about pipeline capacity in terms of how much is flowing through the system when you have your pipes working. And the most successful mitigation measure so far has been the OFO mitigation measure. And I know that that is something that's listed as sort of a new mitigation measure as well, so can you talk a little bit about what value added of the additional mitigation measure and would that realistically improve pipeline capacity?

MS. ELDER: The idea, Commissioner, was that when the -- two years ago when we created the additional OFO rule, or low OFO rule, that is sort of a substitute for daily balancing, we had thought then it was really important for -- to minimize imbalances on the system because every time you've got an imbalance, a difference between demand and supply on the system, storage is how you fix it. So we wanted to reduce how often they had to use gas from storage or inject gas to storage to remedy those imbalances. So that was the genesis of the original Low OFO rule.

Part of the settlement that got adopted to create that rule allows SoCalGas to call both a high and a low OFO on the same day, which in effect creates daily balancing on that day. So instead of having a rule for daily balancing that applies every single day, they can do it under the existing rules just when they need to.

And so what we wanted to highlight for people is that we think that that's going to be needed more this summer than it has been in previous -- than it was last year or the year before that when it first got adopted. And then it probably won't be just the low OFO alone, but they may have to recall both on the same day to invoke that daily balancing on certain days. So it's really sort of a red flag or a flag waving to say we think this is going to need to happen more often. It doesn't really require you to adopt a new rule at all.

MR. RANDOLPH: In the add-on to that you know what we've seen is the most effective of the mitigation measures is that use of the OFOs and to better balance the system. Where there is a hole in that or a weakness in that is that applies only to the noncore customers. And it actually puts -- and I don't know if there are noncore customers who will testify later on in public comment -- it does put an added cost to the noncore customers to comply with those orders because they're unable to hedge as much as they used to be able to be, and there is a substantial penalty risk if they don't.

Those same requirements do not apply to the core customers, which for folks in the audience that don't know, those are largely the residential customers. And the purchasing for that, it's SoCalGas, a different entity than who manages the pipelines, does that procurement. Historically, they haven't been able to balance on a daily basis because meters at the home couldn't read that way, but now with smart meters they should have the data to be able to better balance to actual core demand on a daily basis {and, you know, add a much higher level of certainty to what's in the gas system that day.

Now the PUC does have an open proceeding looking at imposing those type of balancing rules on the core. I think from a timing of that, that definitely would not impact this summer and probably wouldn't impact next winter since some of the issues in there are pretty controversial.

MR. WALKER: Could I ask you to go back to slide number 20 that Katie introduced, and I just want to point out something for the Commissioners. I'm from the Division of Oil and Gas, and we don't have target inventories but our concern is mostly with the reservoir integrity and the well integrity. And on that slide, on the far right-hand column you have the max inventory during those times and on the first six of those is 75 billion cubic feet. And our -- what we do for Aliso Canyon, we establish a minimum and a maximum pressure. And the maximum pressure that we would allow in Aliso Canyon would be 2,926 psi bottom hole pressure, which is approximately 75 BcF. So we would be in the position safely to support the scenarios that you have here so long as on the last scenario, at least 21 BcF went into the other storage reservoirs. So we do agree that what you're considering here is safe from our concerns.

MS. ELDER: That gives me the opportunity to clarify that that column is all four storage fields.

MR. WALKER: Yeah.

MS. ELDER: It's not just Aliso. And the year-end storage column is also all for four fields, not just Aliso. Thanks, Al.

MR. WALKER: Um-hum. Thank you.

CPUC COMMISSIONER RECHTSCHAFFEN: Katie, could you follow up on the point? You had a bullet about physical system mitigation being uncertain. I don't know if that just refers to uncertainty about when repairs and maintenance is concluded or what exactly you were referring to; could you elaborate on that?

MS. ELDER: Sure. What we're getting at there is that both there could be some additional outages that could occur later in the summer. We weren't sure when we drafted this and I'm not sure that we're sure today whether we will have an additional outage or not potentially on line 4000, which is the 270 a day that you see coming in the gas balance at North Needles. We're not sure if we're going to be able to count on that in all scenarios.

There is another scenario where there is 200 a day that potentially disappears out of the Southern system. And so it's those two things that we are trying to test in our additional scenarios, when and where those happen.

In terms of a physical mitigation or the system mitigation, I should call it, there is -- SoCalGas has the opportunity to accept up to 700 a day at Kramer Junction. That would be gas that comes in from Kern River Gas Transmission. And -- but it's not available every day. It's only available when -- I think the way to say it is that when the operating pressure on Kern River is higher than the operating pressure on SoCalGas, so that it has to be able to push that gas into the SoCalGas system, effectively.

What we saw, we looked at -- this measure was actually in place over the course of the winter and what we saw in the gas balance that we did for the winter in our winter supplement that was released on November 28th, we assumed not 700 a day came in every single day at Kramer Junction from Kern River, but we used 625. And I chose 625 because it was the mid-point between 550 and 700. Literally that's where the 625 came from.

We did some analysis of the deliveries that actually occurred over the course of the winter from Kern River, and it turns out that they conveniently average 625, so we used 625 in all of the gas balance analysis that we did here as well.

So there are days where it could be 700, but there are days that it could be substantially less, and so we dealt with that by using the 625.

The other system mitigation gets to deal with Otay Mesa. CPUC worked very hard late last summer, early in the fall to get SoCalGas the permission to obtain 150 a day -- 150 MMcf per day worth of pipeline capacity on North Baja and Baja Norte, which are the two pipelines that connect Ehrenberg then run through Mexico along the international boundary to Otay Mesa.

And in fact when you go look at the deliveries that occurred using that pipeline capacity over the winter, it's very rarely 150 a day. In other words, we're not seeing 150 a day show up. So some of our scenarios made an effort to try to say, well, what if that 150 a day showed up every single day and what if it doesn't.

And in a couple of the cases, -- and I'm going to space on which ones they are, I'm sorry -- we actually bumped it up to 230 a day trying to actually get a system improvement saying we have lost 30 a day on the Southern system due to the expiration of that right-of-way through the Morango Reservation. So I need to make that up at Otay Mesa. Now can I go another 200 a day at Otay Mesa? Yes, I can, but only if it's LNG coming in through Coastal Azul. That's the only way we could come up with to -- with certainty get 230 a day to show up at Otay Mesa because of the way that the -- because of the shippers that are on that existing pipeline capacity who have rights to it and how they use it. There are several powerplants on the Mexican side of the boundary, international boundary who use that pipeline. We don't want to mess with their gas. We need them to get that gas too. But if we had LNG showing up through Coastal Azul, we could have 230 a day every single day at Otay Mesa, at least strike off one of our problems on our pipeline capacity issue.

CPUC COMMISSIONER RECHTSCHAFFEN: I have one other question either for Ed or maybe it's for Alan Walker.

Ed, you started to talk about the lessons learned from the withdrawal of Aliso over the winter and you had just some preliminary results about receipts not matching demand, but did we learn -- what did we learn about how the field actually operated from that withdrawal instance? Did it perform up to capacity as anticipated?

MR. WALKER: Yeah. We were anticipating that there were going to be a very significant decrease in deliverability from the wells and we were surprised that they actually performed quite well with the low inventory that you had in that reservoir. So now they have -- you have to run some long-term experiences because they only ran them for a couple hours each day, so you'd really want to run them for, you know, days on end to see how they will perform long term.

MR. RANDOLPH: From an overall system operating standpoint, I mean there's some lessons learned that we'll be getting into on how SoCalGas operated the system. At the same time the way the withdrawal protocols were interpreted, and using SoCalGas -- using that field only as the last resort, put tremendous pressure on the other storage fields. So those fields, they didn't have any major maintenance issues during that cold spell, but it puts pressure on them. But what it did leave is at the very end of that long cold spell, with the other storage facilities at a point where if the demand had increased, included for a couple more days, there wouldn't have been enough storage in those fields to meet demand in the system, and we could have had problems. So that is a lesson learned that we need to go into -- when we're looking at how the withdrawal protocols are interpreted and used, to make sure that you aren't getting to the point where the other storage fields can't be used at all.

CPUC COMMISSIONER RANDOLPH: So I just want to kind of ask a summary question of how all this fits together. The way I read the assessment is that if we have too many hot days in the summer, we will have to withdraw -- or even if we don't have to withdraw, we won't be able to inject much more into the fields, and then we start winter with less than we need, unless our mitigation measures work. Is that -- am I summarizing correctly? So that's the concern?

We're both nodding yes.

MR. RANDOLPH: I think the report says as long as everything goes reasonably okay, there is not a huge stress on the electric system this summer. There is some risk out there. It does assume transmission capacity. You know, remains there and there is not an N-1-1 type event and some other events out there. But also keep in mind that the scenarios are assuming there's no withdrawals from Aliso, so you also do have the ability to withdraw from Aliso as a last resort. But as you do that and if the Aliso -- maximum amount in Aliso remains the same and you aren't able to inject in other fields as you're withdrawing from the others, we do get going into winter with -- you know in a worse situation than we were last year in terms of what's in storage.

And while December and January were unseasonably warm, if people remember back at how pleasant those months were, we did see the impact of a long cold snap, and it got close.

CPUC COMMISSIONER RANDOLPH: And the other take-away is it would be a much different picture if we didn't have so many pipeline outages.

MR. RANDOLPH: That is very true. I think we would all sleep a lot better if we didn't have these pipeline outages.

CPUC COMMISSIONER RANDOLPH: Okay. Thank you.

CEC CHAIR WEISENMILLER: Yeah. I mean, again, it just sort of trying to summarize on the next winter, I think all of us would like not to be here next fall going through the situation. But I think we're going to have to depend pretty much on what's going on with the pipelines and what's going on with storage inventory, to see whether or not we need to look at more mitigation measures. Anyway, so with that.

MR. ROTHLEDER: This is Mark Rothleder. A comment and a question. I think one of the things I learned from this summer -- or this winter's experience is that these extended periods of curtailment or producing the amount of gas electricity can extend for a longer period of time than just the immediate issue at hand in the cold spell, because basically it extended because they were also trying to refill the storage facility after the immediate issue and that extended the period and the cost period of the impact of that event. That's a comment.

The question is on the LNG and this LNG coming in from Baja has been on there for several times. Is this year, and how is the commercial -- commercially how do you get that LNG purchased and who's purchasing it and who is responsible for achieving it?

CEC CHAIR WEISENMILLER: I think those are affiliate transaction issues that the PUC is going to have to deal with.

MS. ELDER: That's one issue. The first step would probably be to decide who's going to make the purchase, and there may be some regulatory issues around who should actually do it. One can say, well, it's noncore customers who are going to get curtailed, this is a noncore customer problem.

One LNG cargo was probably more gas than a single non -- in fact I know it's more of the gas than a single noncore customer can use, and so it's got to be a group of noncore customers. Could a group of noncore customers actually form, what are the logistics of that? So it may be easier for the core to do it than the noncore.

Beyond that, it's been a while since I actually had to engage in making commercial transactions, but the first step might be to call a broker.

MR. RANDOLPH: Yeah. And I'll just say for the sake of everybody, if it were the noncore to do this, that would probably include some of the electric generation. And it's really easy for us to kind of in a general sense, where the noncore is the big commercial customers, make them pay for it and not the residential. But, A, more of our mitigation measures have been much more focused and, you know, as far as the ones that have cost to them on the noncore customers already. And, two, since the biggest noncore customers are electric generation, and they get to pass their fuel costs onto their electric customers, it lines up with residential customers one way or the other.

CEC CHAIR WEISENMILLER: Yeah. But, again, I think they're affiliate -- if I remember correctly, Commissioner Florio was going to try to work through some of the affiliate issues that would have to be addressed if you were going to get to the LNG issue. Yeah, obviously Mike is no longer around for that issue at least.

MR. RANDOLPH: And I think that's right. If the core is going to purchase it we would have to work through affiliate-transaction challenges.

CEC CHAIR WEISENMILLER: Well, thanks.

MS. RAITT: So as we transition to our next panel, I just wanted to remind folks in the room if you did want to make comments at the end of the day, if you could work with our Public Adviser and fill out one of these blue cards and so we can get you at the end of the day. Thanks. And also for the WebEx folks, to just let our WebEx Coordinator know that you'd like to make comments and use the chat function to raise your hand.

You can go ahead when you're ready.

MR. SCHWECKE: Good afternoon. Thanks for giving me the opportunity and my colleague Dan Rendler the opportunity. I'm Rodger Schwecke. I'm the Senior Vice President of Transmission, Storage and Engineering for Southern California Gas Company and San Diego Gas & Electric.

Dan will be talking about some of the new gas hookups and some of the demand response issues. I will cover the system issues that we have, the system reliability, our assessment of the energy reliability. I think the panel before us did an excellent job of describing the issues, so I will try not to repeat what they have already said, and see if I can clarify some items that I heard that they mentioned that we may have a different opinion about.

So, to start with, a lot of discussion has been going on about pipeline outages and it's clearly from our standpoint those pipeline outages will continue through the summer and the peak EG demand during the summer period. With those pipeline outages, the ability to fill storage for the coming winter becomes challenged. It's not impossible but it becomes challenged. And utilization of the receipt point capacity to serve both summer demand and fill storage, that's where the challenge becomes, so that's where it really lies into what does the winter hold for us -- or the summer hold for us as far as electric generation demand and also what kind of resources do we still continue to have. We have our current outages. As was mentioned before, there is potential for additional outages based on some work that has been done and some results we have to get back on testing.

That all said, without the use of Aliso Canyon, we believe our system can handle a demand that runs between 3.2 and 3.4 BcF a day, which equates and will support in the summer EG demand of about 1.7 to 1.8 BcF a day. That's everything working as we had assessed the system. And, I think as Katie had mentioned before, we assess the system unit at 85 percent receipt point utilization, which is based on our historical rather than what the Joint Agency did which was a hundred percent utilization at receipt point. So there is some difference there.

We do believe that greater utilization of Aliso Canyon can help mitigate some -- any potential curtailments. It also can actually assist in building inventory in the other fields, because when you call at the requirements we have, we want to try to get as much gas in the system as possible. In order for gas to come in the system it has got to go two places. It's either got to go a burn or it's got to go to injection. In order for the gas to be nominated across the interstate pipeline systems and our system, they have to have a place to put it. And if there is no ability to put gas in storage because the other storage fields may be full or limited, that gas cannot get in the system, which actually could reduce the utilization of the receipt points on days when we have low demand.

So very similar to what you heard before. We called at our peak summer demand forecast, which is the same that was provided before on the prior panel, 3.511 BcF, and that looks at core load and noncore load almost identical, 770 million cubic feet a day for each of those. And it's fairly flat, so there's not much peaking to that. There is some slight variation when you look at weekday, weekend, but very small during the summertime. I mean core load is primarily weather driven and you don't have the winter weather during the summertime that will drive a higher residential load. And then we had a resident electric generation demand of about 1.9 BcF, almost 2 BcF when we looked at it. I think that was very similar to the number that was provided before.

So when we looked at all that, we also compared it to what we had -- the information we had on CalISO and LADWP's assessment. We had provided a draft of the technical assessment. And they had a demand, a minimum peak demand, and there has been a lot of discussion of whether they can operate there or not. We just looked at the minimum peak demand of 1.4 to 1.8. whether they can get there or not, I mean it's still dependent upon their import supplies, which is a hundred percent utilization of the import capacity, and other contingencies, and that is clean -- and last one contingency.

So we talk about receipt point capacities. You look on the -- the column on the left is the best-case scenario that we have, which shows that Blythe, Otay Mesa is utilized, but that whole zone. And we have two different things we have in our system. We have an individual receipt point and then we have a zonal capacity. In other words, when you have more individual receipt points coming into a location where the entirety of the zone or the pipeline is taking gas away from those points, where that capacity is less than the individual receipt point capacities. So when you look at Blythe and Otay Mesa, that's one zone, where we had the best-case scenario of a little over a BcF available at Blythe, we assumed 200 million a day available at Otay Mesa. Didn't even have what was the reduction to 270 million a day at North Needles. And then to zero which was at Topock, which relates to that Line 3000 outage. And I will talk more about line outages going forward.

We actually looked at assuming 600 million a day of deliveries at Kramer Juncture, very similar to what Katie had assumed at 625 in her gas balance analysis. And then we had the other points. We came up with a receipt capacity of about 2.9 BcF. We again factored down to the assumed utilization of that receipt point capacity of about 2.5 BcF.

Now in the worst case. The worst case is very similar to the numbers that they had assumed for the prior panel in the Joint Agency Technical Assessment. What we looked at, though, is if you have North Needles out of service, we do expect to have full capacity at Kramer Junction of 700 million a day. So that gets us to a scenario where you have 2.4, 2.5 BcF or receipt capacity. Our factor looked at if we have 85-percent utilization, that would only be 2.1. So that's how we looked at our summer assessment, those bounds. Whether you achieve 85-, 90-percent utilization will depend on how the market goes.

I think one of the slides they had in the last presentation talked about the price increase. You would expect that when you have $20 gas at the Citygate that you would have great utilization of the receipt points. That was the period of time in which they were showing they weren't having -- we didn't have full utilization of receipt points. So there's something else behind it that does not allow full utilization. And when you think that any gas that gets to California has to be sourced back at the supply basins, whether it's Texas, Rocky Mountains, those areas. Is there something else along the supply chain or is that gas already sold to somebody else.

There is not a pool of gas sitting at the SoCalGas border waiting to be bought. It all has to be brought all the way back into the supply basins.

So we put together this map, very similar to the map that was shown before. I think it's very difficult, but I think what you can see is the big red X's and the yellow X's. These are related to the pipeline outage that we have.

And I will take the very top part of the screen where you have that blow-up section. That Newberry is our Newberry Compressor Station. We have two lines that come into Newberry Compressor Station. You have Line 4000 and Line 3000 coming into that -- 235.1

I should say and Line 3000. Then you have 235.2 and Line 4000 going out of that compressor station. So you got two lines coming in, two lines going out. That's how it was designed. They go a little bit off in different directions. They come from different sources. The two lines come in and one comes from North Needles or the Transwestern Pipeline. The other than one comes from Topock, which is the El Paso or Kinder Morgan Pipeline.

So coming in, we know we had Line 3000 out of service. We were still able to keep 800 million a day of flowing gas through the single line, unlike today at the 270. What you have now is you have the outage on Line 235.2, the rupture. The picture you saw that was in the prior presentation showed what happened at that location. At that point, both lines, 4000 and 235.1, are running in parallel, about 25 feet apart.

The yellow X we have there is the derate of Line 4000 that we put in place after the incident on Line 235 to ensure and enhance safety. The single biggest ability to reduce stress on a pipeline and to mitigate risk is to reduce pressure, and we did not want to have another incident like we had on Line 235.

In addition to that, we knew that in March of 2018 we had to complete a pig run on Line 4000. We did that in February. Those are the results that we're awaiting to get back to see what is the condition of that pipeline, especially in comparison to the root-cause analysis that we found on Line 235. That root-cause analysis has been completed and now we're trying to synthesize that information into what has to be done on 235 and how does that apply to the information we get on Line 4000.

So that's the reduction that we're currently seeing at where you have one pipeline coming in at the Newberry Compressor Station and a partially reduced line leaving it. That's the restriction.

The other restrictions that we have, and we obviously -- if you look down at the bottom part of that chart, you have the three lines that run in that blow-up section, that's the line outage in 2000, where we had to take that line out of service. That runs across the Morongo Reservation. That was the incremental 30 million a day of receipt capacity reduction that we have today currently. A reminder. We already had that line derated to be able to perform pigging work and pipeline integrity work that we had to have done, so that line was already reduced by 210, and that has been since 2001 -- 2011. Excuse me.

The other restriction, the other yellow X is Aliso Canyon, and that's the restricted operation at Aliso Canyon, not only from an inventory standpoint but in order to follow the withdrawal protocol that's been established. So you see how that all looks. I mean you obviously don't like to have red X's on your pipeline system, but this is where we are today.

We also took a situation of what happens to our storage inventory. And these two graphs are our assessment where inventory may be, based on certain circumstances. Looking at a withdrawal need from non-Aliso storage fields of 1.32 BcF, or 1320 MMcfd, through the summer and into winter, when we looked at our best-case pipeline scenario, we can get there. I mean we barely get there. There is some reduction. We do fall below it slightly towards the end of the summer, but we get there. Again, that's the best-case scenario of all pipelines working throughout the summertime. So you can see we get at the non -- and these are only non-Aliso storage fields. And that basically says we can get to somewhere around a 40, 45 BcF in those other storage fields.

Under a worst-case scenario, which is the bottom where the lighter-gray bars along with the blue line, you could see that under that worst-case scenario we're in a considerable problem because the amount of demand during the summertime will require use of those storage fields, and that will draw down the capacity. Not only does it draw down the inventory capacity but, like we experienced just last winter, it draws down the withdrawal capability, that ability to deliver gas on a moment's notice to meet demand, which is critical during the summertime. I think a lot of the discussion about the summer demand, really we're talking it occurs over a large part of it, over a 10-, 12-hour period. There is those short -- those periods. And also it occurs rapidly.

We did also look -- in this case we assumed where would we be if we did have 95-percent utilization of receipt capacity, we did get closer to the numbers we needed to have. So when you look at maintaining, you know, what we're doing to maintain summer reliability, we're obviously focused on increasing our inventory levels, having gas in the ground is a way to help mitigate any issues we have during the summertime and in the coming winter.

We filed -- Ed mentioned we filed our advice letter (phonetic) that was directed by the Commission, or by Energy Division. That is, I think, on the agenda this week, which really would drive trying to get more gas in storage, as quickly as possible. A little -- there a little bit of inconsistency between what we're trying to do to push gas in as quickly as possible, because what that does is if it fills up storage fields, and we assume it will, then those storage fields will not be available for injection. And if you're not available for injection, as I mentioned, that will limit the amount of gas that can actually be brought in the system on a given day of low demand. High demand is a different scenario. But low demand, you won't be able to continue to fill it up.

Also there are limitations in our Goleta storage field and getting gas up to Goleta. We do expect to have work. We had a pipeline that went out of service during the Montecito mudslides and debris flow. That line was out of service with one of two transmission lines to move gas up in that area. That's why we drew on a lot of Goleta storage significantly this past winter because we did not have the ability to move gas up there from the basin.

We will continue to work with CalISO and LADWP. I think the relationship has grown over the last two years out of necessity but I think also because just the common good. And we will continue to work with those agencies to try and make sure that we have -- everyone's aware of the situation that we're facing.

There was great communication and coordination this last winter, and we expect to continue that going forward. We'll obviously use our OFOs. And, if needed, the Aliso Canyon protocol, which the Aliso Canyon protocol does include curtailments. The current protocol requires a reduction in electric generation demand before Aliso Canyon is used.

So one thing I'd like to state is that this last winter, had that restriction or need to use the Aliso Canyon as a last resort. All the curtailments to electric generation customers could have been met -- could have been eliminated had we used Aliso Canyon.

The amount of gas that was curtailed or has shifted could have been met by Aliso Canyon. Yes, we would have had lower inventory at Aliso Canyon, but the amount of gas may only have been two and a half to three BcF of additional withdrawals out of Aliso Canyon could have avoided all the curtailments this last winter.

So with that, the other thing is, you know, maintenance. We're continuing to schedule maintenance only during low periods. We don't have any major maintenance except for the work on the pipelines. And we're still reviewing all the Technical Agency's report and we do have excuse me concerns about assumptions and conclusions. And we would like to have a conversation about the viability and practical implementation of some of the mitigations. We don't want to have where the medicine that we try actually has more side effects than basically we solve, so more problems could be created. But it's something we can go through and have a conversation and describe how the implementation may or may not occur.

So, with that, that's my side of the presentation, and any questions you have, I'm more than willing to attempt to answer. I don't know if you want Dan to go first or...

CEC CHAIR WEISENMILLER: Sure, go ahead.

MR. [SPEAKER]: Here to load up the -- yup.

CPUC COMMISSIONER RECHTSCHAFFEN: Well, obviously we're very, very concerned about the outages and the repairs and the constricted pipeline capacity. And I'm just wondering if you could tell us more about how you prioritize your maintenance, your repair, you know, what factors you consider in deploying people. Do you hire more people to deal with the situation when it's more urgent? Do you think about reliability impacts when you're doing your system repair?

MR. SCHWECKE: So when we look at a repair of a pipeline, and I'll use the example we had on --

CPUC COMMISSIONER RECHTSCHAFFEN: Or just general maintenance, I mean repair or maintenance, you know.

MR. SCHWECKE: Well, I think maintenance is not the issue with regard to the outage that we currently have today. Those are basically, you know, potential for corrosion and anomalies that occur in the pipelines that are underground that were not really maintained per se. It's external to the pipeline. And that's why we have the pipeline safety rules, the pipeline integrity rules that require us to pig those pipelines, to inspect those pipelines. And we go through the normal cycle.

When we run that pig, which is like we just ran in February on Line 4000, that's when we find the issues. Those are the major outages; those are the anomalies that we have. First of all, immediate repair conditions, where we have to go in and basically either cut out a section of pipe, put a band on that piece of pipe, that requires us to take that pipeline out of service. When we take that pipeline out of service, we basically will do all the work and we will hire all the resources and all the contractor to move that as quickly as possible.

Those lines, I think to give you a little context of just how long it takes, the incident that we had on Line 235 is five miles along a right-of-way road. Dirt, one-lane right-of-way road in which we have to maintain less than a 10-mile-an-hour speed limit. And we have to have biologists on site because of the desert tortoises. So you have to maintain five miles.

So you can think to move a lot of resources every day, -- and people don't stay on site. To move five miles less than 10 miles a day, a lot of resources, you eat up half the day just getting to the worksite. And you look at that having multiple sites. So what we have done is have multiple crews doing the repairs once they have been identified. We did that with our recent Line 4000 and we brought that back into service.

So you know the issue we had on Line 235 caused us to reduce the pressure. That was the work that was just bringing that line back into service where we had multiple crews the end of last year to get that line back into service as quickly as possible. Hopefully I answered your question.

CPUC COMMISSIONER RECHTSCHAFFEN: So you're saying you're deploying as many resources as needed as quickly as possible, sort of full court press, every time you're identifying a pipeline in need of repair or a problem?

MR. SCHWECKE: We are deploying all resources that can safely perform the work on the pipeline and managed on the pipeline to do the work for the period of time. You can't have unlimited resources because the congestion on some of these work areas would actually delay the process. We are deploying and utilizing contractors to the greatest extent possible for the work to be completed safely.

CPUC COMMISSIONER RANDOLPH: And you have parallel sets of crews working on the different pipelines that you currently have out? So, in other words, you're sort of at full capacity for each outage that you have right now?

MR. SCHWECKE: So the Line 235, we do not have a remediation plan to bring that line back into service. That was dependent upon the root cause analysis, so there is no work that's actually being completed on that pipeline.

Line 4000 is currently operating. We are not performing any work on that, but it's reduced in pressure. Once that line, the information on the pig results come back, we will deploy whatever resources we need to address those issues. And it may be one issue and it may be 50 issues that we have to address. And we will basically address each of those and we'll operate and bring in crews whether it's multiple crews or it's one crew doing all the trenching, one crew doing the -- you know, to optimize the speed in which those repairs can be made.

Now I will say what we did do, we had Line 3000, we had crews on Line 3000. The immediacy of the issue we had in Montecito, we did have to move some crews from Line 3000 to deal with the Montecito incident. What that did is it did delay the work on Line 3000. However, from a receipt capacity standpoint, if you remember my graph, bringing Line 3000 back into service does not increase the capacity of our system because the constraint is downstream of the Newberry Condenser Station.

So those are the only work that we have, is really on Line 3000 and the Montecito at this point in time.

CPUC COMMISSIONER RECHTSCHAFFEN: I think you said you're conscious of ensuring that you're minimizing maintenance activities during peak demand periods. Can you talk a little bit more about that?

MR. SCHWECKE: Well, what we will do is just like with the electric system. We will defer maintenance if needed or we will try to accelerate maintenance during the period of low demand to be ready for a period of higher demand. We have accelerated some maintenance at our Playa Del Rey storage field so we wouldn't be hitting that during a potential period of higher demand. Once we get into high-demand periods, they will set -- you know we will call a restricted maintenance and have hands off. We don't want anyone to touch the pipeline, performing maintenance, or take anything out of service. So we will juggle that. Obviously we will not delay safety related. It's very difficult to delay any compliance related. But any elective maintenance, we will defer.

CPUC COMMISSIONER RANDOLPH: I'm going to shift topics for a second. Did you have any more on outages?

CPUC COMMISSIONER RECHTSCHAFFEN: Yeah, I had one other question which is do you have contingency plans if there are more outages? We're talking about remedying what exists and what we know about already, and we heard from Katie and others that there may be additional ones. What is the back-up plan or what is the contingency plan for dealing with those?

MR. SCHWECKE: Well, the contingency plan, at least what we have put forth, is actually to try to get as much gas into storage as quickly as possible, and that assumes all storage fields, not just the non-Aliso storage fields.

We also look at we will have to go out and look at supplies from any and all resources that we get those supplies in, and maximize the receipts. That is the contingency, to get as much gas in the system and to have as much capability to meet the demand during the summer period and the coming winter. Likewise, once we have an outage, is to get that line back into service as quickly as possible.

MR. ROTHLEDER: I have one question on outages as well. Does this comparative historical outage rates, is this pattern that we're seeing now a higher outage rate than we've seen in the past and before Aliso Canyon, and what is your -- what's your feeling about the cause of that if it is a different outage pattern, or are we just being more sensitive to it because of Aliso Canyon?

MR. SCHWECKE: Well, I think it's -- Mark, I think it's a little bit of all those. One, I think we are seeing a higher outage rate. The one item that really added to the complexity was the rupture on Line 235. Because had we had everything -- we had everything planned with regard to the pig runs knowing, one, that we take Line 3000 out of service, we have to do the pig run on Line 4000, that goes out of service, but you still had two pipelines, one going into Newberry and one going out, that could provide 800 plus million a day of capacity. But also it's compounded by the limited use of Aliso Canyon. That was our single largest resource available to us to meet energy reliability in Southern California. That is somewhat taken out of the equation. And when you do that, it hurts and it makes it much more difficult and sensitivity on when you have other outages.

CEC CHAIR WEISENMILLER: A couple questions, Rodger. One is what is the age of your system, at least the pipelines where issues are coming up?

MR. SCHWECKE: I don't know exactly, but I think Line 235 was 1960 vintage. I think Line 4000 and 3000, I think, and I'll have -- we'll have to get to you on that, but it's more of the 1950 vintage. Those are the only pipelines that we have been seeing a lot of anomalies.

You take the lines on the Southern system, we don't see the same type. So is it the soil conditions that we have in those areas that are creating more problems. So we have a variety of vintage supply pipelines. But the PSEP Program that was approved is going through, and the Pipeline Integrity Program, and we're replacing a lot of sections of pipe. A lot of the work on mitigation is actually cutting out and replacing with brand new pipe. And we have done a lot of that on Line 3000. Depending on what happens on Line 4000, we may have to do some of that on Line 4000, likewise on 235.

CEC CHAIR WEISENMILLER: Do you have a sense of what the root cause is on 235, if you can say?

MR. SCHWECKE: You know, I don't have the technical assessment and I haven't looked at the final draft, so I'd rather not speculate on what it is. We're going to be sharing that assessment with the Safety Enforcement Division of the PUC, along with the Office of Safety Advocates at PUC. So we'll be working through and discussing what that -- just like the assessment was done by a third party, it wasn't done by us.

CEC CHAIR WEISENMILLER: When do you expect sharing it with the PUC Safety people?

MR. SCHWECKE: I would expect us probably within the next week.

CEC CHAIR WEISENMILLER: Okay.

CPUC COMMISSIONER RANDOLPH: Yeah, you mentioned your PSEP. Was the pigging of Line 4000 sort of on schedule with your -- the rest of your PSEP Program?

MR. SCHWECKE: So that would be the Federal Pipeline Integrity Program and the requirements to pig pipelines. The due date for that reinspection line, because we have inspected that line once before, was March of this year. We did it in February. And we want to do it as soon as possible because the sooner you do it, the sooner you get results, the sooner you can mitigate any potential issues. And we were trying to push that as quickly as possible to hopefully make sure we can get that line back into service before the peak winter -- summertime and the peak wintertime.

CPUC COMMISSIONER RANDOLPH: And the rest of the maintenance that you have been undergoing, setting aside 235 which was obviously an unplanned issue, is consistent with your -- with your PSEP?

MR. SCHWECKE: Yes. PSEP and Pipeline Integrity.

CPUC COMMISSIONER RECHTSCHAFFEN: You mentioned there are some mitigation measures you have concerns with. Can you tell us what they are?

MR. SCHWECKE: So the assumption, and I'll start with the assumption, the assumption of a hundred percent utilization I think people in the industry, you rarely get a hundred percent utilization at a receipt point because that means you have to someplace for the gas to flow and the entire supply chain has to work.

CPUC COMMISSIONER RANDOLPH: So you guys assume 85. Is that industry standard? Where did you get that number?

MR. SCHWECKE: That's based on our historical utilization. So that is a question. When you take a mitigation, I think one of the mitigations is to have the system operator buy supplies, like we do for the Southern system, what we do on the Southern system is just to ensure a gas is flowing at a particular point. We immediately -- we buy that gas and immediately sell that gas to the Citygate to a customer. We don't hold onto that gas.

So that actually has a customer not buying supply but buying from us to the Citygate. So you can't do that exact same thing if you're trying to increase receipt point utilization, because if I buy gas at a particular point and sell it, they're just not buying gas somewhere else.

The other thing is does that impact the number of high OFO's that we have, because now we're bringing in supply and is there possibility of now there's too much supply in the system, or are we competing for supplies for other people that need those supplies. Those are the issues you have to walk through.

I think you have the same and similar issues when you look at supplies at Otay Mesa on a base load firm basis, because at some point you're pushing other supplies out the system. That's why in order to move that gas, right, buy those additional supplies, which you'd have to decide when do you buy them in the day. There's nomination cycles, there's two nomination cycles before the day of actual use. The first one, basically people make the request. The second one, they try to adjust to make up for where there's supply deficiency. That occurs. And then third one is where they try to also adjust to maybe if we have a high OFO. How long do we wait before we buy those supplies and allow customers to actually buy their own supplies.

On the Otay Mesa, if we're buying those supplies and we have a low demand, we're going to be actually pushing other people off the system, because we just can't take all the gas. If we had sufficient injection capacity, which is like a demand on the system, then your amount of gas you could flow in you can optimize the amount of receipt point capacity because then you could flow a lot more because your demand plus your injection capacity is higher than your receipt point capacity.

CPUC COMMISSIONER RANDOLPH: So if your historical experience is 85 percent, is that consistent with other gas utilities?

MR. SCHWECKE: I don't have that information on the utilization.

CPUC COMMISSIONER RECHTSCHAFFEN: Is that it, though, a hundred percent utilization, pipeline utilization, are there other things in the mitigation measures that the assessment identifies that you disagree with or have concerns about?

MR. SCHWECKE: Well, I think, you know, obviously continuing with OFOs, we don't have a concern. I mean we've been having OFOs and use that as a tool. The two that draw the most concern for me are: How do we deal with trying to buy gas at Otay Mesa and the other is a system operator buying gas on a given day to try to fill up the receipt point. Incentives more to get the customers may be more of an avenue. And I know customers may not like to hear it, but you go to more of the daily balancing scenario with tighter tolerances, which will force them to buy more gas, and I think every single customer will cringe when they don't know what their demands are.

There is one thing I would like to correct that Ed said. Core customers and the gas acquisition group that buys supplies does balance and is required to balance. Now they're only required to balance to a forecast number. They're not required to balance to the actual number, but they are required to balance within the same tolerances of the noncore customers. During the summertime forecast issue for the core is not that big of an issue because the load doesn't change much during the summer.

MR. RENDLER: Well, good afternoon. I'm Dan Rendler. I'm the Director of Customer Programs and Assistance for SoCalGas. I'm glad to be here this afternoon. I'm going to talk, as Rodger mentioned, on a couple items. The first is going to be on winter demand response and the second on gas hookups, new gas hookups.

Before I jump into -- there we go. Before I jump into the actual demand response, I'd just like to state that the foundation for any demand response is really a robust energy efficiency program, and at SoCalGas we're very proud to have one of those. Just this past year we saved our customers, the residents and businesses in Southern California, over 39 million therms, in the past five years about 146 million therms. So that's foundational and something we think that's important to note upfront.

Regarding winter demand response, we are also proud to be the first gas utility to implement a demand response program and gas demand response program. And, as you can see, in 2016-17 it was the initiation of that and we had a couple different efforts and one was looking at a mass market notification campaign and then looking at for noncore customers as well as for core customers and then a pilot for rebate on it. The second piece, to 2016-17, was the smart thermostat. So that's when we initiated the first smart thermostat effort, had about 320 customers. But during that year we did not call an event, a smart thermostat event where we would control the thermostats.

In 2017 we continued the smart thermostat load program January through March, and we actually did have an opportunity, and I we will through that on future slides, to implement and execute the demand response effort.

The second thing in 2017 and '18 was looking at a demonstration project on demand response capabilities for water heaters, so that is underway as we speak out of energy resource center, and we're currently looking at the technology and working with one of the water heater manufacturers and we're hopeful by mid-summer so to have the results of that, and I will talk a bit about how that fits into our longer-term plan relative to demand response.

So this is just a quick snapshot of how the program works. So we have, I should mention upfront, that we have been partnering with DWP and with Southern California Edison on reaching out to customers and signing them up for these. So the initial purchase of them, and that partnership is going well. I will talk a little bit later about how we plan to reach out to other municipalities in our service territory to continue to do that as well. And the idea is to get them to a point where they can -- we can do kind of dual enrollments with both, so they can sign up both for, in Southern California Edison's case, their Safe Power Days during the summertime and then of course our demand response during the wintertime.

But the way it works is the thermostat would be lowered by four degrees during a period of system constraint. And those time periods that we had worked with the new manufacturers is between 5:00 and 9:00 a.m. and 5:00 p.m. and 9:00 p.m. Those were picked thoughtfully about the times when most of the potential for restraint on the system, and they also were consistent with the vendors' practices as well.

As far as the funding, we do have an upfront purchase incentive of $75, but this is also for the participation. So they received a $50 incentive for enrolling and then also a $25 incentive for remaining on the program through the program.

And then I should mention also the way that they're notified is either through a mobile app or messaging directly on the thermostat or in an email. So the way that -- the way the process worked was when we identify we are going to have an event, for the next morning we would let them know the evening before. And then on the app that's going to be in the evening, we let them know in the morning. So they get a two-hour notification that will either come on their thermostat, you know, it's whichever preference they had to be notified.

CPUC COMMISSIONER RECHTSCHAFFEN: Are there any incentives to purchase the thermostats or is this just for customers who have them?

MR. RENDLER: No. It is -- there is an incentive. It's $75 from us and I know Southern California Edison also has incentive, so they can actually get incentives from both.

So here is kind of a recap of the program so far. So we have roughly just under 11,000 thermostats. And the difference in those two numbers is that some homes have two thermostats in them, so that gives you a ballpark of the numbers.

The events that we had called were two events, one from February 20th through 23rd and then the 26th through March 2nd. So you might recall we talked earlier about what the weather was like at that time as well too.

The program itself goes from January to March. And in some of those cases, you will see where it says seven activations and six activations, so if you do math there are more activations than days there. And the reason for that is in some cases we actually had to activate both in the morning and in the evening to do that.

So just from an operational perspective, that was a bit of a challenge. When we were working with the manufacturers and being able to do it twice in one day was something technology wise we had to work out, and also looking at some of the notifications. So in the first go-round of events, it was very educational and we've definitely got some lessons learned as we continue to look at escalating this into increasing the scope.

So if we look at the bottom slide there or the bottom bullet there, so the 60 percent of the thermostats actually completed full four-hour activation, so fairly low. I mean we would like to have a hundred percent when we do that. Twenty percent of those thermostats opted out before the start or during an activation, so they can opt out of the program. And then the bottom one there, the third -- the 20 percent of thermostats never received the activation signal due to various reasons.

So the two primary reasons there were that the thermostat was either off or it was, interestingly enough, in a different mode. So albeit, being very cold out, it could have been in AC mode, or something. It might have just been that way technically on the unit. The good news is in both those cases they wouldn't be consuming energy, but we're working with the vendors to determine how we might manage to do that to make sure that something doesn't change during the activation cycle if they're in these different conditions.

And then also we're currently waiting for the final assessment on the load impact, so I wish I could share with you the specifics and the details of the success on this from the load perspective, but we're expecting by the end of the month to have that from an independent third party. So as soon as we have that, of course we'll make that available.

And, just as a statistic, we have about 250,000 thermostats, smart thermostats in our service territory, in SoCalGas's service territory.

So path forward for winter demand response. Ed had mentioned earlier about an advice letter and an application. So the left side there is the advice letter that we will be filing shortly. I guess the message I'd like to leave here at this stage is that we're committed to provide our customers with energy solutions that best optimize their -- best optimize energy. So that's a way of saying that if we believe the smart thermostat is here to stay and it's something that we can continue to expand and to build on.

We currently have an advice letter in now for a pilot program for our low-income customers, so as part of our ESA Program and looking at how we might incorporate that into that program as well. And then we are also looking to do direct install and do that with our partners and also look at a form of -- I'll call it auto enroll. So when you get the thermostat and we install it, we look right there to try and get them enrolled into the system, so it doesn't take a separate step and require them to reach out. So these are a couple ideas that we're looking for and just basically to build on the learnings that we have experienced through this first round.

We're also looking nationally too and learning where others have started programs, and I will talk about that in a minute. But to close out on this coming winter, so our plan is to continue with the smart thermostat program, to include other DR-capable thermostat brands. Right now we have two, so we're going to reach out to others and start building that network as well too.

And then to increase participation from the just under 11,000 we have now to 50,000. So there is a technical glitch with being able to have a customer use our demand response program and Edison's, say, Power Days with the thermostat, so it's kind of one or the other. So we believe in the next couple months or so, hopefully in time for winter, that we will be able to fix that glitch and then therefore we can really work that kind of cross-enrolling folks across our programs.

Looking a little bit longer term and looking at the application that will be filed by the end of this year and more permanent funding and a more permanent place for demand response in our portfolio, again to continue to expand our program even further, but also to look at pilot residential water heaters. So this is where I mentioned in this last round we have a pilot going on looking at connectivity of the water heater.

So the thought there is that should we be able to prove out the technology and the capabilities, is that you would be able to set a water heater remotely to like the vacation setting, so to drop it down during times of peak and need as well too. So that's one area.

The other area is to explore technology and tariff based demand response, so from a technology base we're aware the national grid has been -- I think they just finished a pilot around boilers and furnaces and looking at controls for those, mostly heating, much colder. So we have a difference of weather and -- generally speaking. And, you know, here in our area, but we're still learning from that and the capability and seeing are there things that we could consider on the CNI side that may also have an opportunity. And then looking at things such as any rate determinations, etc. So we're still in the early phases of working through that, but those are some of the areas that we're looking at and considering as well.

So that's pretty much the demand response. I can jump into the -- shall I keep going? All right.

So the next area I have been asked to speak about is the new gas hookups. So get to the next page here. So a fairly busy slide here, but I just wanted to give you a little bit of framework before we go to a couple of the graphs that you have in there.

But our residential forecast is driven by new housing starts. In the past we had used permits for construction, but we felt that since new housing starts, kind of shovel in the ground, is more realistic and is a tighter number, so now we're using those as a precursor to look at active -- or to look at meters and new meters.

Just as a stat, over 95 percent of our customer hookups are residential. And if you look at the SoCalGas forecast for active residential meters, so we do have some inactives. We took that into account where they either -- maybe it's a rental that's not being utilized or a vacant property and such, so those were taken into account, but the growth rate of about .7 percent per year over the next years. And we looked out and you will see in the forecast we are about three years in on this particular area. And we looked at, you know, pretty much the common economic activity and assumption, so assuming that the economy goes that's array of .7. And, again, this is meters, so we'll talk about the forecast. I have another slide that talks about the actual usage per meter.

And on the commercial side and industrial, the forecast is declining. And what I will show you in a graph a little bit later is that the commercial is fairly level to slight increases. But industrial is clearly -- you know, it is reducing.

And, just a note on the long-term use forecasts, this uses weather, normalized usage, looking out over the -- we're looking past 20 years, so it neutralizes it for the weather.

So a very busy slide here. I will just call your attention to a couple of things. I mean the obvious recession. But if you look at 2017, you will see that our forecast was actually below, so we under forecasted. It looks like around -- I don't have the exact number, but just over 40,000 new homes in that area. And when we look further into that we look into kind of a similar state and we're really focused on the three years. We realize the out years that there's lots that could change, you know, relative to that, but at least in the next two to three years we made an estimate of that.

So, again, this is active residential meters. So I want to make sure we're clear on meters, and it's the change. So it's incremental, it's not the base load of all the existing ones. It's just looking at the increase. And, just as a note, our estimates are about 60-percent multi-family, 40-percent single-family. So that has switched over, you know, the recent time where now there is definitely starting to be more multi-family.

And so this is forecast that we put together for looking at single-family and multi-family for the next three years. I will note a couple things. The information on use per meter is based on 2017, weather normalized. So that's how we use that. And we have compensated for a historic home that is probably less efficient and looking at multi-family home. So you have single-family and multi-family there.

Also just kind of a rule of thumb. For an existing home, it's about 447 therms per year and for a new home it's about 335, so we use that also as kind of a base line when we look at forecasting and such.

So this next slide is probably the one that gives good insight. So even though I'm showing an increase in the actual new meters, if you look at the overall therms per meter, they have -- you know increasingly they're consistently then reducing and we see energy efficiency playing a very large role in that over time. And we see that continuing into the future. So when you look at this information along with the forecast, the overall forecast on the residential side is decreasing slightly. So, again, the slide before I showed you was around new meters. This information about per-meter usage shows an overall reduction in the residential consumption.

And then the final slide I have is just one to give a perspective on commercial and industrial meters. So you will see it looks fairly -- it's going down over the years, you know, substantially during the previous two years but in a small uptick. Commercial is actually rising, as I mentioned, a little bit in here, so I didn't bring a commercial and an industrial one, so this is combining both of them. But clearly we're seeing a reduction in industrial businesses leaving the region and such. On the commercial side, there seems to be some uptick in certain geographic areas, but overall it's fairly flat and with a modest increase.

So those are the slides that I had prepared and I certainly welcome any questions.

CEC CHAIR WEISENMILLER: Thanks.

So we're actually running a little late, so if you have a question go ahead.

CPUC COMMISSIONER RECHTSCHAFFEN: I don't have a question for Dan. I just wanted, Rodger, at the end, before you left, you have all the regulatory agencies here and you have expressed clearly your view about use of Aliso and increasing reliance on and increasing inventory, but apart from that and the request you have already made to the PUC, is there anything you're expecting or needing from the regulatory agencies to maximize your ability to avoid curtailments in the summer and the winter? Is there anything that we need to be working on? If there is, we'd like to know it now so that we don't get into a problem later on.

MR. SCHWECKE: You know besides some of the things we already talked about, if we do get in a situation that we have identified work that needs to be clean on Line 4000 to bring it -- allow us to bring it back up in pressure. A lot of times what delays the process is getting permits and getting permits from Fish and Wildlife, getting permits from other agencies. So any support that could be provided in that arena would be greatly appreciated once we get the work identified.

I think -- you know I won't belabor the point on Aliso Canyon. It's just making sure when we're looking at everything, we are again looking at all the side effects as we move forward. Let's not -- you know the old saying cut your nose off to spite your face. Let's make sure we're fully aware of what happens and how it has to happen because if we go in without that clear understanding of what is going to happen, when it's going to happen, and how it's going to happen, we could make a situation worse, so for this summer anyways.

If we look at going forward, and I think Chairman Weisenmiller brought up, you know, as we're looking at infrastructure projects, I think looking at those infrastructure projects and realizing that pipelines are getting older, I think there are -- we have applications -- you know, I think just a full understanding of the issues when we're looking at safety aspects of the pipeline and the potential for replacing pipelines so that we don't have these issues ongoing, that's something else to consider.

CEC CHAIR WEISENMILLER: Thanks. Thank you.

The last panel. Good afternoon.

DR. NAJM: Good afternoon. My name is Issam Najm. I am the President of the Porter Ranch Neighborhood Council, speaking here today on behalf of the Neighborhood Council and the tens of thousands of residents that call Porter Ranch home.

I'm going to move through this quickly. It's been 928 days since we all learned of the blow-out of Well SS25 and it's been 817 days since it's been technically capped.

I do want to start by saying thank you to all the entities starting from Governor Brown's Office, the CEC, PUC, CAISO, and LADWP for all the work that you have done so far and you continue to be doing. We heard a lot of it today. I do want to make a slight note, if I may. If would be wonderful if we can stop using the term "in ten years" and say "by 2027," because that directive came in 2017 and we seem to be carrying that "ten year" forward every year, so setting a year number on it would be much appreciated.

However, we're also -- we'd also like to be blunt and say that we are very disappointed in the way SoCalGas has been responding to the needs of the community as well as all the directives that have been given to them. We feel that they have made every effort to stop the process that we are all shooting for.

I also want to say that we are also greatly disappointed in the number of public agencies, cities and municipalities, who may be here in the room today, that's fine, who have ignored the fact that this facility is a harm to a community just like their communities.

Our position at Aliso Canyon is quite clear to everyone. In November 2016, we asked Governor Brown and our elected representatives to work towards the permanent closure of the facility. We laid it out in our position letter and we have sent -- spent a good half of our lives since then dealing with it and working with it.

But I also know that a lot of people say what's your problem, the well has been capped, why are you here, why are we doing all this. I would like to answer that question today so it's clear as to why we are in this fight.

The facility constantly leaks and we need to appreciate that. This is a graph of data from CARB, CARB's website, and I intentionally did not try to redraw it to make it more legible. It is simply a cut-and-paste out of CARB's data. These are the fly-overs over Aliso Canyon.

The facility releases gas even when it's not operational. These are all after the well was technically capped. They stopped in October 2017, I don't know why. I would like to ask CARB that question, but that's a question for another day.

The 250-kilogram per-hour limit was set by DOGGR and the PUC, and the facility cannot even meet that limit. And I would like to emphasize that is an arbitrary limit that was set. And when I asked where that number comes from, where DAWGR came up with that number, the answer was this is what CARB considers normal for a facility of this size. They basically told us CARB does not make a distinction -- in that statement, my interpretation, that CARB does not make a distinction whether a facility of this size is next to an elementary school or in the middle of a cow pasture. Makes no difference as to what is an allowable release out of a facility, and I would like you to think about that.

We cannot be okay with that. How much will it release when it's allowed to go back into the operation that the gas company is looking for? But having said all that, it is not about methane. We are not concerned about methane. We are concerned about all the other things that this gas has with it.

This is a graph from CARB's monitoring station during the four-month blow-out. There is a very strict relationship between the benzene content and the benzene exposure and the methane release out of this facility. For whatever reason, in this facility there is a clear relationship between the two.

Benzene, as you all know, it is a silent killer. It is a known human carcinogen, and there is no doubt about it. What other silent killers are in this gas? As a community, we don't know. We just cannot ignore this fact.

But benzene is not the only one based on the data that we gather. This is a compilation of 29 -- and this is a partial list -- of 29 chemicals that are released by Aliso on a continuous basis, and this was all before the blow-out. These are from AQMD's database. This is the average of 2000 to 2014 pounds per year of priority pollutants, by the way. All the red bars are bars of chemicals that are associated with cancer.

Take this list under normal releases and imagine what it may have looked like during the four months of uncontrolled blow-out, then put your kids in the middle of it, and you can understand why we have this level of anxiety. Unfortunately, this is a topic nobody talks about.

And one other thing, health effects data are all developed on an individual-chemical basis. You ask any toxicologist, they will tell you what the health effects of benzene are, they will tell you what the health effects of ethylbenzene are, the effects of formaldahyde. But if you ask any toxicologist, what would happen if all three of them are together, they will throw their hands up in the air, say: We don't have a system to answer that question.

And yet we are looking at this cumulative exposure of toxins, and so the idea that the exposure is below what is referred to as a threshold level on an individual-chemical basis is not good enough, because we have a compounded effect that no one can explain to us what that is.

They claim that Aliso is critical because gas travels at 20 miles per hour. San Diego does fine without a storage field a hundred miles away. Call me naive, but I'd like to understand why. Gas travels about a hundred miles from McDonald Island, San Francisco. Is the current capacity sufficient for all conditions? I am the first one to say no, and I agree with everything that's been said. But can it be? Yes. Because it just takes someone who wants to get there from where we are here. And I see that a lot of agencies want to get there. I just wish the gas company would jump on that train.

If I may just propose a few ideas for your consideration. Talking about lowering demand, I would ask that energy generators, especially LADWP, consider peak shaving at gas-fired plants, especially using LNG with liquefaction. This is a reasonable, long-term solution to address peak shaving and maintain that lower demand during peak hours -- or product-side energy storage as they see necessary for them.

I think it's time we talk about removing the bottleneck between Honor Rancho on the LA Basin. This issue comes up every time we talk about the max capacity out of the Northern Zone and Honor Rancho. You cannot maximize both of them because there is a bottleneck between the two. It would be good to work towards removing that bottleneck.

For what it's worth, I would suggest considering compressors in critical low-pressure zones in distribution system based on hydraulic modeling.

On the home side, I would suggest incentivizing home owners to use heat pumps, especially in new construction where a single unit achieves both objectives. And I would also suggest that you incentivize home owners to utilize in-home battery storage coupled with rooftop solar to be able to load on the day and have some reserve for nighttime to reduce the swing in pressure.

Another thought I would like to suggest for LADWP, if there is any chance to consider a pump storage system, utilizing the lake -- that I just forgot its name -- where solar energy is used to pump water up during the day and bring it down during the night for generation. There are projects in the state that have looked at that between two water reservoirs, and that's a viable approach in the long term for balancing the swings between day and night. Just a thought.

In our opinions, and if I may be blunt, for three pipelines to be down for the winter season is inexcusable and highly convenient. SoCalGas has shown no interest in moving to a future without Aliso

Canyon. In our opinion, it's using all its resources to derail the effort to implement the Governor's directive. The fact that one entity owns and operates the entire transmission, storage, and distribution of a majority energy resource for more than half of the state is wrong and should be of concern to everyone.

I would suggest for the PUC to consider a proceeding to separate these assets between mutually-exclusive entities that have no financial connections, or for an accountable public agency to take over the transmission and storage system.

The Neighborhood Council continues to be gravely concerned about the impact the facility has had on the health and well-being of our community, our families, and our children. That is the core issue for us. We continue to be gravely concerned about the threat this facility poses in the event of a seismic activity.

A repeat of the 2015 blow-out should not be acceptable to anyone, and we certainly cannot accept that. The system needs to be modified to do without the facility. We do urge the PUC and all parties to work towards what we have coined an expedited and responsible closure of the Aliso Canyon facility with a clearly-defined scope and schedule, and for the cessation of oil and gas operations in our backyard because Aliso storage is not the only thing going on out there and we have many instances of releases intentional or otherwise that were from the gas operations in the system.

So, Mr. Chairman, I want to say Chief Justice Rehnquist once said you cannot unring a bell. This bell has been rung. To this community, we now know a lot more about the perils that this facility creates in our midst. We cannot unlearn that fact. We cannot go back to the idea that all these releases from this type of facility is okay to have next to our homes and families.

We appreciate the effort that you're doing and we hope that the schedule will be set and we're not playing back and forth on should we or should we not use Aliso. Let us set that schedule, put that calendar in place, and figure out the plan to implement the project that needs to happen to get there. The gas company will continue to make money, its stockholders will continue to have their value. We're just asking for a shift in perspective, to recognize that this cannot exist next to the community that exists next to it. Thank you, Mr. Chairman.

CEC CHAIR WEISENMILLER: Thank you.

Our next speaker, I think we're losing ten minutes, so let's go to CCST to cover that speaker. Let's cover the panel. we may have follow-up questions, but at least I want to make sure we have some chance for them to get their comments in.

MS. LONG: Great. This is Jane Long. Can you hear me?

CEC CHAIR WEISENMILLER: Yes, we can.

MS. LONG: Okay. So please change the slide.

So the California Council on Science and Technology, which is an organization formed by the Legislature with the intent to address technical and scientific issues that are associated with policy from an independent point of view, so we are not advocates. We assembled a committee of experts to address three questions which the Legislature asked us. And those three questions had to do with gas storage in the state as a whole. So we are not addressing Aliso Canyon specifically.

Those three questions had to do with the safety, are these facilities safe, what risks do they pose. The second question is do we really need them for energy reliability now. And the third question, given the fact that the California has aggressive climate goals which will significantly change the energy system in California, will we need them in the future. Please change the slide.

So I'm not going to speak too much to the first question and I'm not asking you to read this very complicated graph, but I want to explain what it is. Each column of this graph, of this table represents a different facility, gas storage facility of the 13 facilities in the state. And along -- and each row represents an aspect of risk. For example, is it vulnerable to flooding or landslides or has it experienced former events that were risky. And what you see in color is darker colors mean that it's riskier. On the face of it, a site is riskier than a site with lighter colors.

And so what we found, two major findings of the first question, which I'll just go over very briefly and then get onto the reliability issues, are that the regulations that are being put in place now are vastly improving the -- they're going in the right direction -- are improving the safety of issues such as caused the blow-out at Aliso Canyon. And, secondly, that all of these facilities are not the same. And should the state be able to reduce the use of gas storage as they look at -- and these sites are all now required to do risk assessments, more formal risk assessments that will quantify these kind of risks, so they aren't just darker colors or lighter colors but some way to actually compare them, that they could use this understanding to try to -- if they want to consider closing facilities, they can take the risks into account.

So my two messages here are that these sites are safer given the new regulations, significantly safer; and, two, that they're not all the same. Change the slide, please.

So as to the reliability question, the report is a thousand pages and has a lot of information on different aspects of reliability. And I'm not going to talk about all of them, but the one that we found was the dominate one for determining whether or not we need gas storage is the winter demand for gas. And, in particular, if that winter demand was -- could be met, that all of the other needs, all of the other uses of gas storage would also be met. So this is a good way to look at whether or not we need -- currently need gas storage, because if we need it for this purpose then all the other purposes are available.

So basically the problem is simply one of mass flow, that we can import 7.5 billion cubic feet per day of gas, and there are times in the winter when we need to deliver 11.8 billion cubic feet per day. So over 50 percent of the -- more than the impact capacity can be required on a fairly regular basis in the winter, and so meeting that winter demand really requires that we have storage. Can we change the slide.

So we looked at what it would take to replace it. And basically in the very short timeframes of 2020, we didn't find any easy way to replace it. We did look at both additional pipelines and peak shaving units. They came closest. They cost somewhere between 10 and $15 million. They have their own risks associated with them, pipelines and compressors, and whatnot, all have an associated set of risks. And they do commit California to new gas infrastructure, which may or may not be part of our future.

So -- and we also looked in a lot of policy and market mechanisms and found much that they would reduce the need -- they could reduce the need for gas, but they would not obviate the need to have gas storage to meet the winter peak for heat. Can you change the slide, please. Maybe -- I'm sorry. Could you -- well, I'll just say it. Don't go back.

We also looked at 2030 and decided -- and came to the conclusion that there would not be a sufficient change by 2030 to change that conclusion.

So the important thing is to understand what that winter peak is for. That winter peak is not caused by demand for electricity, it's caused by the demand for heat. And heat in California is generally provided by gas as a direct use, not through electricity. And as we look at what's going to happen in the future, we are looking at some of the basic policies that California has to expand renewable energy. And this being at this point mostly domestic solar and wind power. And these resources decline dramatically in the winter, particularly wind. In California, wind dies down dramatically in the winter. Solar dies down every night and then dies down on average in the winter by some 60 percent.

So if we tried to solve this problem by electrifying heat, such as with heat pumps or other electrical forms of providing heat, instead of using gas, and we continue on the path of changing the energy system to meet the emission guidelines by continuing to add solar and wind, such as we have now, we are creating an issue because those resources go down when the peak goes up. And that is part of the reason why CEC -- sorry -- ISO, CalISO has required a back-up, amount of back-up for electricity from gas equal to the amount of renewable energy, that capacity that is also online. So please change the slide.

So to drive this home, these horizontal lines represent the peak and average electricity demand and you see for a winter month and a summer month, the amount of renewable energy that is available over time. And so you see in the winter some very -- some periods of really no solar or wind being available. And even in the summer some periods are hardly available.

So if we are to manage this system, we have to have some kind of back-up and the back-up is basically filling in the trough formed when -- when the renewable energy is not available. Next slide, please. The next one, okay.

So to take a closer look at this, this is the January month and the June month, these periods, which are known in Germany as *Dunkelflaute*, which means dark doldrums, these conditions, we have to think about what can provide that. And I think what I want to make the point here is that it's going to be quite difficult. I have clicked the slide and I think they should be animated.

So this -- well, you've got them all there, so that's fine. On the left you see the California Energy Storage Mandate. Assuming that the 1.3 gigawatts that are required actually last for six hours, and you can see it's very -- that that storage mandate is not coming anywhere near being able to fill in these troughs. And if you look at the largest energy storage that we have right now, the hydro facility at San Luis, even that is not going to come -- not going to be able to -- several of these would not be able to solve the problem, and several of them might be hard to come by. Next slide.

Oh, well, finally, there is typical battery storage, which are -- has a two- to eight-hour duration. So the conclusion here is that batteries and energy storage are unlikely to be able to obviate the need for gas storage as a method of backing up renewable energy in the winter, particularly if you want to -- and that problem will be much worse if we try to electrify heat. Next slide.

So basically the conclusion, the high-level conclusion of this report is that we don't really know yet how that system is going to work in 2050 and we don't know exactly how we're going to come up with a reliable system of energy that is also very low emissions. And so this graph is just a cartoon of some ideas about some choices that California needs to make before we can understand whether we're going to need gas storage. And it also is making the point here that it might not just -- might not be -- that some of these choices might lead to reducing the need for methane storage, but they might not reduce the need for gas storage.

So, for example, if you have a high amount of renewable energy, and the horizontal bar, if that's your choice, then you have to do a lot more to figure out how you're going to back that up. And if you give -- if you say that you're going to be using carbon gas to do that, then you're going to be adding carbon capture and storage to the system and you're going to be using gas storage as well. And if you take a path there of saying we're not going to use a lot of carbon gas, then you may be doing things like building a lot of changes to the kinds of intermittent renewables that you have.

If you, on the other hand, decide that you're not going to have as much intermittent renewables and you add a lot of flexible generation, such as wave power or geothermal or being in Wyoming, bought Wyoming wind, then you are going to have choices that may allow you to give up some gas storage, but you may also need, for example, in the left-hand box some size of CCS -- (audio distortion) -- storage of gas underground.

So I don't think this is -- this is basically not very well thought out. This is just trying to give the idea, but the message of the report is until we understand how these choices are going to be made, we aren't going to know whether we still need gas storage of some sort in the future. Next slide.

So the conclusion is that we need some kind of flexible resources in the system. And when we know what those are and we know how those work, then we'll know something about how gas storage should evolve and what kind of gas storage should evolve in the future, and basically we found no studies that did that. This study is based on existing literature. It's a meta analysis. We didn't do any modeling for this study, but some modeling studies that would examine how the energy system is going to work on all time scales including the seasonal time scale, needs to happen in order for California to know whether it needs gas storage and what type. Change the slides. I think that was my last one. Okay.

So I think I've said most of this, but I would probably emphasize the second bullet here, that only some form of chemical energy storage, so some kind of fuel, in other words, and all of these require underground gas storage, can -- at this point are -- are technically feasible for supplying power in the *Dunkelflaute* conditions for multiple days and seasonally. There is nothing big enough except that. Again, electrification of heat could cause -- and doing without that flexible resources will exacerbate a problem and create a demand for electricity at the same time that electricity output declines.

The solution to -- the most likely solution to eliminating the need for underground gas station is more flexible, nonintermittent or base load greenhouse gas resources, such as geothermal, CCS, nuclear, Wyoming Wind, wave power. Those are the most likely solutions to moving away from gas storage. And, finally, we need a plan for -- we need a plan for that on all time scales. Thanks.

CEC CHAIR WEISENMILLER: Thank you.

Let's go onto Gill Ranch.

MR. WEBER: Good afternoon. Thank you for giving us the opportunity to present. We have far fewer slides than anybody else. The next slide, please.

So we on the Northern California system have looked over the many years about the potential opportunity to bring the abundant supplies of Northern California gas supplies on the PG&E system through down to the Southern California system. And, as the gentleman from Porter Ranch noted, and was noted before, one of the -- this is not without requiring some de-bottlenecking on the system, especially from Honor Rancho into the -- into the valley there. So we believe greater connectivity between the PG&E and the Southern California systems could provide cost-effective storage service to Southern California.

We have abundant storage on the Northern California system. We have fully independent storage providers. I think the point was made earlier about having an independent storage provider in the valley as opposed to having it all completely integrated around one party. That's in effect what's happening in Northern California where there independent storage providers, the transmission system is put off from the local distribution company at PG&E. So there is a model for how that would work and there is over a hundred BcF of independent storage, provider storage capacity on the PG&E system. We believe that a pathway could be created. Next slide, please.

Using the existing system, and I'll get to a slide in minute, which is my last slide, with an interconnection at a location called Arvin, where the PG&E system and the interstate system come close together, that a compressor station and interconnection could be built to bring Northern California gas supplies onto the Southern California -- or the system serving Southern California. And that gas could augment the gas supplies that are coming from elsewhere and provide much quicker supply of gas, as opposed to having it come from the Permian or far eastern parts of the system supply.

So we think there is an opportunity there. We have done some modeling of that. We have a pretty good idea of what it would take to build a station. If you look at this map and you look at where Honor Rancho is, and we're talking about, I think the gentleman mentioned earlier, hundreds of miles. This is certainly within the 100- or 150-mile range to bring gas into the valley. So not without things that needed to be done, not without hydraulic modeling that needs to happen, but there is the potential there that we wanted to make sure what's considered, as we're discussing the supply of gas to the Southern California area and how it comes in as opposed to just thinking purely of existing pipeline capacity from the east. So let's move to the next slide.

So the next slide gives you a picture of what we're talking about. So there is a PG&E Backbone Station and a Kern Mojave Station that are 1400 feet apart. So this is the length of pipe and you can see these are farmer's fields that this pipe would be laid in, and a compressor station would most likely built on the Kern Mojave into that, but could be built on the PG&E end of it as well to allow an interconnection between the PG&E Backbone system, which at that point is headed east and west, or the way it's designed today it's headed towards the west, and that could open up an opportunity to bring gas in that.

All of the independent storage provider facilities in the Northern California system are in very rural areas. Gill Ranch is 30 miles to the west of Fresno. They grow grapes and pistachio trees around us. It takes about three miles just to get to the nearest highway. It's actually paved from Gill Ranch. Wild gooses out in the delta. The Central Valley is out in the -- in the delta area. They're out in rural country. So we're all located in rural areas. And if you go back to the CCST presentation, you will see that all of us have younger wells. And one note on the presentation that Jane presented, that first slide lists the average age of the Gill Ranch well of 39 years, it's actually 9 years. That's a typo. So we talked to CCST about when they put out their presentation a number of months ago, and requested that they redact it.

So just so that there is no misunderstanding, all of us built our wells within the last 20 years. They're well maintained. And we're working to comply with the DOGGR regulations.

So existing capacity. This 100 Bcf of capacity exists. It doesn't need to be developed. The pipeline interconnection is easily built between the Backbone system and the interstate system at that location. So I think as you look for reliability and look at the future, we strongly recommend that there be modeling done to see how this supply coming onto the Southern California system could help alleviate or -- or change the thinking in terms of supplies in Southern California. I think that's my last slide.

CEC CHAIR WEISENMILLER: Okay. Thank you.

Let's go onto Dave Ashuckian, speaker.

MR. ASHUCKIAN: Good afternoon. I'm Dave Ashuckian. I'm the Director of the Efficiency Division at the California Energy Commission. And although it may seem a little out of place here, I'm going to talk about our 2019 Building Standards that are going to be considered for adoption tomorrow.

The nexus is that for the first time we are going to provide an all-electric option. But let me just talk here about the kind of the overall goals and the progress for our standards.

So our 2019 Standards have been working towards the long-term goal of achieving zero net energy by 2020 for residential construction. But it is also working towards the goal of contributing to the state's greenhouse gas goals and, in fact, a home that will be constructed using the 2010 Standards will produce about half of the greenhouse gas emissions that a home that was constructed as recently as 2000 is consuming.

And, in fact, if you use an option that we're going to offer for all-electric homes, the reduction in greenhouse gases is 83 percent. Significant reductions there.

We're also promoting self-utilization of the PV system by encouraging demand flexibility and grid harmonization strategies. we'll talk about that more in a minute.

And, again, for the first time, we're offering independent compliance pass for both mixed fuel and all-electric homes. Mixed fuel meaning natural gas and electricity, as most homes are built today.

And, finally, we're providing the tools for local governments to adopt local building ordinances that achieve zero net energy through what we call the green code, or Part 11 of our reach codes, that go beyond what is the minimum required for California. And for the first time, again, we are changing the way local ordinances can compare and adopt those standards using what we call an energy design rating.

So we haven't ventured too far away from our primary goal of efficiency. And in that energy efficiency is still our number one goal for Building Standards. And, in fact, we looked to maximize the cost-effectiveness of efficiency first. And that we have improved a number of measures that improve the efficiency of the envelope.

Again for the first time, we are going to require PV on every residential construction home in California and that is considered to be cost-effective based on the long-term rate projections as well as the cost of -- the current cost of PV in all 16 climate zones in California.

And, finally, we are offering options for grid harmonization that include batteries and other onsite storage options that improve the interaction with the grid, so that we try to minimize the actual load from the grid.

As I mentioned, for the first time it's possible now for builders to build an all-electric home and not even have gas connected to the building at all. The impetus of heat pump water heaters and heat pump HVAC systems have gotten to the point where they are considered to be cost-effective, providing that they also make sure that there is enough PV to offset the additional electric load as well as making sure that there is a couple more measures that improve the efficiency so that that load is reduced slightly more. But in fact we'll have an option now where a builder could build an all-electric home from the start.

And we wanted to make sure that requiring or building an all-electric home wouldn't require solar panels increase in size to the extent that we would actually discourage the construction of all-electric homes. So there is again the analysis that shows that you don't have to increase the size of the panels to achieve the all-electric homes requirements.

Now that I mentioned -- oops, let's see. It jumped a bunch of slides here. I will go back. Sorry. Not going back.

So, as I mentioned, there are two parallel compliance paths. What we have is called a prescriptive path. That is a mechanism where you just meet the desired standards of a home and you put those measures in and a builder can build the home as-is. We also have what's called a performance path where builders can design the home using different measures, different mechanisms so that if they want to tailor or customize the home away from the standard design, they are well to do that. Literally, they only have to require a heat pump water heater that is tier 3 in order to meet or exceed the standard design for the all-electric home, as one option. Or they can actually put in a compact hot water distribution system and a heat recovery drain system in order to achieve that additional efficiency to make that all-electric home as efficient as the mixed-fuel home.

Is there someplace I should be pointing this thing? Because it's not -- okay.

Again for PV sizing, for Part 6, that's the requirements under our mandatory requirements. The requirement is that the PV system net out only the electric load, so we're not achieving the full zero net energy as a result of the gas consumption, but we are achieving zero net electricity with these 2019 Standards. And, in fact, if a customer wants to install a larger PV system, we are not giving increased credit so that they're offsetting additional benefits of efficiency by putting in more panels. We don't want people to build giant systems with lots of PV and not an efficient home, so that if the system isn't working properly they're actually going to end up relying on the grid more significantly.

And, again, the option is if you want to install a battery system, we are going to give credit to a battery system that utilizes the onsite PV generation, again in an effort to maximize the onsite consumption and utilization of that energy such that it minimizes the load on the grid.

And, finally, we have changed the way the mechanisms are evaluated for compliance. We are using what we call an energy design rating. We have a model that identifies what the energy consumption is. We have separate scores for the efficiency elements that a builder would incorporate and a separate score for a PV system. And obviously the more efficiency elements you incorporate, the lower score. And the more PV you put on, the lower the score. But there is a minimum required PV -- efficiency element and a required PV element such that you're not trading off between PV and efficiency, to make sure that the house is as efficient as possible, as well as having the minimum size PV. And, again, builders can use any combination of those to achieve compliance.

The benefit of the energy design rating is that if a local organization wants to adopt what we call local ordinances that go beyond our standards, they can simply choose an energy design rating that is more stringent than our standard requirement and make it very simple, they can go from any points to a significant level higher than what our minimum requirements are.

I will add that there are about eight cities and counties in the state who have already adopted local ordinances that exceed our standards, that actually require PV today. Those cover about ten percent of the state's population. And so, you know, expanding that and, again, these standards will make it even easier for that to happen, especially as the building code promotes the full electrification of homes. Next slide.

Next steps are we are scheduled to consider adopting these standards tomorrow at the Commission. After that they go to the Building Standards Commission, which will approve them for incorporation into the Building Code. And the effective date of the standards will be January 1, 2020.

However, I do want to point out that as of today, any time a local jurisdiction can adopt a local ordinance, it has to be reviewed and approved by the Energy Commission to ensure that it is at least as efficient as the Energy Commission's minimum standards, but any local ordinance can be adopted today that would exceed our standards and achieve the full electrification of homes and that would essentially help mitigate the long-term challenge with reducing the gas load on Aliso Canyon.

And that concludes my presentation.

CEC CHAIR WEISENMILLER: Thanks, Dave.

So let me see if anyone has any questions for anyone on this panel.

CPUC COMMISSIONER RANDOLPH: I just had a question for Dr. Najm.

Can you talk a little bit more about your suggestion about the compressors at the low pressure points in a distribution system?

DR. NAJM: Sure. The analysis that was done in the technical assessment last year, and I assume it's in this one here, where the gas company does hydraulic modeling and looks at the system wide and defines there is a critical point where if you draw any more, the pressure is going to go below that critical level. So it's a pressure bottleneck in the system at that location. And so the idea is, is there any work being done to consider removing that bottleneck by adding a compressor at that location to remove that pressure restriction and allow you to move more gas through that point.

CEC CHAIR WEISENMILLER: Okay. So let's go to public comment. Let's start with EDF. Please.

MS. BURGA: Hello. My name is Irene Burga. And I am a California Oil and Gas Program Manager for the Environmental Defense Fund. And EDF is a national environmental nonprofit.

So, first, let me start by thanking the Commission and the joint energy agencies for their continued commitment to providing communities and organizations like us with information on their ongoing evaluation over the impact of Aliso Canyon on the region's energy reliability.

I also want to recognize the importance of the analysis conducted by the California Council on Science and Technology that laid out the implications of both maintaining the status quo and the pitfalls of not taking into account a systems-wide approach to planning for economy-wide decarbonization, in particular, the fact that we may find ourselves even more reliant on storage for energy system reliability if we don't plan for thoughtful reduction in gas demand for both thermal and electric needs.

One of the issues that EDF has paid a lot of attention to in the period after the Aliso Canyon disaster are the energy market rules, which led to the region's heavy reliance on natural gas storage for supply reliability and some of the options available to reduce it. In particular, we have focused on the opportunity to reduce the need for natural gas storage to act as the unquestioned supply source for firm gas deliveries across the region. Furthermore, we evaluate how the region's heavy reliance on storage, a resource which supplies regional powerplants with on-demand gas without those plants having to pay for that service, undermines the price signals which could spur investments in clean energy resources that can also supply the market that gas-fired plants are supplying.

In our analysis, we see that although it may be possible to manage the risk of future disasters through comprehensive safety and integrity standards, that simply is not enough. Rather, California needs to also implement key enablers for reducing peak and base load gas demand through tools available to it now, some of which we have heard today such as through better use of the billions of dollars worth of investment in advanced metering technology and infrastructure for conducting both better day-ahead and real time forecasts of demand, both of which will reduce reliance on storage as a source of supply when under forecast occurs and as a source of market when gases are parked in storage because of over forecast.

So we would -- we should be required -- requiring utilities, such as SoCalGas, to modernize their gas-acquisition systems to create real time transparency in gas pricing, and so to build out the systems needed to accurately price the value of guaranteed gas deliveries to electric generators. Until the joint energy agencies develop and implement strategies to reduce both the need for gas and gas storage to provide volumes of energy to meet energy demands, the system overall will remain vulnerable to the events like what happened in Aliso Canyon.

So thank you and I hope you consider these comments.

CEC CHAIR WEISENMILLER: Okay. Great. Thank you.

It turns out our court reporter needs a five-minute break -- yea, you don't? Okay.

THE REPORTER: I had -- I had to leave, so I took it.

CEC CHAIR WEISENMILLER: You took it, okay, good. Okay, good.

THE REPORTER: I took it.

CEC CHAIR WEISENMILLER: Good, that's good. Do it.

So let's go on to the next public comment. Also from Porter Ranch.

MR. PAKUCKO: Also, did I miss somebody? So my name is Matt Pakucko, of Porter Ranch, a Note Valley (phonetic) resident for ten years, and President of a nonprofit called Save Porter Ranch.

So no one seems to have addressed the manipulation of the gas orders by SoCalGas that preceded at least two of the times when they used the Aliso facility. And there is public data that shows that they did not order enough gas on at least two occasions and causing this false need for Aliso Canyon. I think you guys still need to look into that.

Also let's do a little root cause analysis on what's going on here today. Ed Randolph earlier mentioned what's really going on with the SoCalGas system. Is SoCalGas properly managing their system. We could also apply that to the CPUC. Don't take this as any kind of offense, because there's things that if we're looking at, you know, a system problem, we need to look at the regulators as well.

I mean the Baker testimony back in 2014, where SoCalGas themselves, where they have a negative well integrity trend, which means deterioration of their facility, there was no action by the CPUC, and then SoCalGas did no maintenance, followed almost immediately by the gas blow-out. Perhaps that all had been -- that disaster could have been avoided if all agencies had just, you know, been doing their jobs better, DOGGR included.

So now SoCalGas has been crying about they don't have -- it's very time consuming to repair their remote pipelines. Now do they have the resources to do this? Now during the blow-out, the problem with stopping that blow-out is SoCalGas did not have resources available to manage the problem at their facility and thus part of the four-month blow-out because they couldn't deal with it. So they and perhaps PUC still haven't learned, because now SoCalGas is out there flailing away saying, hey, we can't repair our pipelines. They and you, I suppose, need to learn how to address that better, how to regulate that. I mean that's your job, to make sure that stuff can get done.

There has been a lot of scrutiny about SoCalGas and it's very well deserved, but we really should look at what the CPUC is doing as well. The safety review from SB380, come on, guys, this is unbelievable that this happened. You guys had the final authority over that safety review being approved. DOGGR said, hey, it's good to go, the facility is safe. You guys agreed, you concurred. Followed immediately within two weeks, 33 percent of their wells failed, 33 percent. I mean, come on. Who's minding the store? Were any of you involved in that decision that, hey, this place is safe. DOGGR was on the end there. That is like -- that's mind-blowing to all of us.

So I mean I think if we're talking about reliability, the CPUC needs to dig into itself and see if you guys are reliable. Thank you.

CEC CHAIR WEISENMILLER: Thank you.

Jane Fowler.

MS. FOWLER: Hello. Thank you for being here. And I appreciate the questions you are asking these specialists today.

I live in Grenada Hills. And, okay, this morning I woke up, I hadn't opened my eyes yet, and I felt this -- you know what I feel on many occasions when something is leaking, this like feeling of -- I can only describe it as like electric feeling. Everything is tingling and pulsing. And, you know, before I open my eyes, I feel like scared because I don't know what today I'm going to feel. You know, I have a headache, my body aches. I'm lethargic, nauseous all the time. My sense of taste is gone, sore throat. And this is -- we're not in the blow-out. You know, this is two and a half years later. And I'm still feeling, you know, physical aches and pains. And, I'm sorry, it's hard to share this. But, you know, and I've been trying to share, but, you know, it just takes a toll on your body.

Two and a half years is what they're saying has been leaking but, you know, I feel like it's been a little longer than that. But, anyway, it takes a toll on your body, it takes a toll on your mind, it takes on you psychologically. I think neurologically something is going on. This is, you know, pretty much ruining my life. It's hard to explain. Like because you're feeling so bad all the time or quite a bit of the time, it changes the way you relate to people.

For example, I don't really say, say, I'd like to go out to coffee or, you know, go to this or that with anybody because I'm afraid that I'll commit to something and I'll have to uncommit because I'm not feeling well. And I don't want to be that person who is always canceling.

It changes my relationship with my husband because, you know, I don't want to be seen or heard or, you know, I feel like I'm going insane, you know, like something hurts, which I don't want to be that person. I want to be strong, I want to be, you know, able to function.

It changes my relationship with my kids. Like I don't want to talk to them because I don't want them to say, mom, how are you doing, and I don't want to say anything negative. I want to say something positive.

So please think of us at Aliso Canyon that whether it's manufactured or not, or whatever, something is still leaking and we need help. Please.

CEC CHAIR WEISENMILLER: Thank you.

Helen.

MS. ATTAI: Hi. My name is Helen Attai and I'm the -- everything I wanted to say Dr. Issam Najm covered it very eloquently. I cannot speak like him, but since I'm here I'm going to just give you a few words.

The first thing is pipelines. We need to know why those lines are out, why they have been out for so long, why is it that they cannot fix it. That's unacceptable. I mean taking -- it's been more than six months already, just pipelines. Can they fix it.

And why is it that they are insisting on doing a root cause analysis on those pipelines in the middle of nowhere, but they did not want to do a root cause analysis on Aliso Canyon, which is really close to all these homes that we are living in. This thing doesn't make sense.

Another thing, CPUC, I hope you guys don't get offended, but this is the fact, just listen to this statement. You guys have appointed a judge to do a reliability -- the judge is saying that SoCalGas needs to do a reliability study on SoCalGas to see if a SoCalGas facility is needed or not. Do you see the conflict of interest in that or is it just me? I mean this doesn't make any sense. You don't realize that you're studying yourself. Of course you know what the result is going to be. I mean, come on, you guys, give us a little credit.

And I'm sitting here listening to everybody and unfortunately all I hear is about pipe savings, savings, you know, lessen or worsen, your maximum amount of gas, gas balance, and all that. But the only person I heard brought up the safety issue and our health was Dr. Issam Najm. That is not being taken as any factor, you know, when you guys are talking about it or making decisions, and it's a big, big, huge factor. Six teachers from one school, six teachers from one school have died within just a mile from this facility. So many people are sick, so many people are dead, so many pets are dead.

My own husband, he is a very healthy tennis player, fit guy, I have to call 911 on him for him since December twice and once taken to urgent care. I have taken my daughter to urgent care. I have been sick. We are suffering there.

I don't understand what part of that you guys don't get. We having here. This is my second year in a row being here. And one other thing I would really appreciate, if you guys come to our community for this meeting. I don't see any person on that panel, I don't know why they're in this building and why they are here. If you want to talk about --

(Chime.)

MS. ATTAI: Well, you guys, you're one, and it's all so many of us. You can come to our neighborhood and we can talk about Aliso there, please. So more --

CEC CHAIR WEISENMILLER: Thank you.

MS. ATTAI: -- people can participate. Thank you.

CEC CHAIR WEISENMILLER: Okay. Joe Crecco.

MR. CRECCO: Good afternoon. I'll be brief. I just wanted to take an opportunity and say thank you very much for working through the reliability issues down in SoCal.

And just wanted to remind folks that as with Middle River Power, Senior VP of that entity, we own and operate the High Desert Facility as an NQC of 830 megawatts. We're also building out a solar facility with storage there and also own the coastal geothermal site. I just want to remind folks that there are alternatives. It's definitely not a local need but for different flex opportunities and system. We do have High Desert there. It's run off the current system. It's not off of Aliso (phonetic), so just want to be -- have folks be mindful that we do deliver into the Victor sub, and from that allow the maintenance of -- or maintain reliability for the system.

We also want to let folks know that we are spending a bunch of money in outages because we do believe in the importance and the need of reliability in the South, so we're spending over $40 million over a two-year period to upgrade these facilities because, based on what Neil Millar said, understanding how the duct curve is working, we have turned a base load facility into a peaking unit. We're a three-by-one unit at High Desert. Semens units, we've now converted to a full peaking unit. And over the last couple years, we have been running pretty much on the -- from hour 17 through 24, and we're improving times to start up and shut down. So just really wanted to take two minutes to let you guys know that there is and are reliable options to help support reliability in Southern California. So if there are any questions, I'd be on the dance room.

CEC CHAIR WEISENMILLER: Thank you.

Is there anyone else in the room?

Then let's go to the telephone line. We have one party on the line.

MS. RAITT: Yes. We have Andrew Krowne.

Do you want to go ahead, Andrew?

MR. KROWNE: Yes. Hi. Can everyone hear me?

CEC CHAIR WEISENMILLER: Yes.

MR. KROWNE: Hello. Thank you very much for taking my comment here through the web. Thank you to all the parties that are having this session today.

I want to point out, as has been done by other members in the room, there is a human cost to running these facilities. There is a human cost in health which is not only measured in money spent to procure one's health but also in the quality of life. And those folks who live anywhere near these facilities, whether it be Honor Rancho or Aliso Canyon or anywhere else, pay a very grave price. That is something that must be factored into these types of analysis.

It is very distressing as a member, as a family man who went through the Aliso Canyon blow-out that the gas company is very quick to do a root cause analysis on a pipeline in the middle of nowhere, yet years later and through much consternation we still don't know what's going on with Aliso Canyon, and every year we have these meetings with the need to rush Aliso back to full service. There is something just not right there.

I also find it very troubling that we cannot get a number of very important pipelines back into service very quickly. This is a company with immense financial resources. There should be absolutely no issue with obtaining the very best crews to do the very best and quickest work on these essential pipelines. So to sit here and listen to and hear that a pipeline has been offline, I believe

I have heard since 2011, is just befuddling to me.

Why is it that the PUC and all the organizations are willing to give the gas company an open-ended time line to get these resources back online? On should be pushed back online as quickly as possible.

Now in the wake of all this I developed an application to track the health issues of folks who live around Aliso Canyon. That's about two million people. The data we get is staggering and must be compiled and used in this type of analysis. There are thousands of people reporting thousands -- tens of thousands of symptoms due to releases related to Aliso Canyon and those some of those specific chemicals were pointed out by Dr. Najm -- and thank you very much for that presentation.

I would be more than happy to work with any of the organizations there today in order to provide data so that you can see the human costs to these activities. Thank you very much for your time.

CEC CHAIR WEISENMILLER: Okay. Thank you.

Anyone else on the line?

Okay, then we're going to transition to -- to come up.

I want to thank everyone for their participation today. It's been a good opportunity for us to delve into these issues and to listen to concerns, so thanks. And, again, written comments are due May 22nd. So, please. Thanks again.

(The meeting was adjourned at 4:42 o'clock p.m.)

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CERTIFICATE OF REPORTER

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 1st day of June, 2018.

Martha L. Nelson

MARTHA L. NELSON, CERT**367

CERTIFICATE OF TRANSCRIBER

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

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

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

Martha L. Nelson

MARTHA L. NELSON, CERT**367

June 1, 2018