BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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CALIFORNIA INDEPENDENT SYSTEM	:	Docket No.
OPERATOR CORPORATION	:	ER16-1649-000

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STAFF TECHNICAL CONFERENCE

Friday, September 16, 2016
Commission Meeting Room
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

The Commission met in open session at 10:01 p.m., when were present:

COMMISSIONER NORMAN C. BAY
COMMISSIONER CHERYL LA FLEUR
COMMISSIONER COLETTE HONORABLE

FERC STAFF:
VIRGINIA CASTRO, OFFICE OF ENERGY MARKET REGULATION
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MARK ROTHLEDER
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CATHLEEN COLBERT

CALIFORNIA ENERGY COMMISSION:
KEVIN BARKER

P R O C E E D I N G S

MS. CASTRO: Good morning.

I would like to welcome everyone to today's technical conference to discuss the California Independent System Operator's market rules that were implemented to address the limited availability of the Aliso Canyon Natural Gas Storage Facility.

My name is Virginia Castro. I'm from the Office of Energy Market Regulation. I will be moderating today's conference, along with my colleagues here seated at this table.

I do want to thank all of the participants for being here with us today for what I am certain will be an informative discussion.

For those of you that have tuned in via Webcast, please take the opportunity to download the PowerPoint presentations that are located in the link underneath the Webcast, as well as on the FERC.gov's calendar of event.

Your attendance today highlights the importance of this topic, and we greatly appreciate everyone for taking the time and making the effort to be here with us.

I also would like to thank Commissioner LaFleur, who is here with us this morning, seated to my left.

The purpose of this technical conference is to provide Commission Staff and interested parties the opportunity to discuss lessons learned regarding the efficacy of, and the need to retain, any of the tariff provisions accepted by the Commission in the order issued on June 1st, as well as to discuss any potential longer-term solutions that are needed to address any ongoing limitations at the Aliso Canyon facility.

We will begin the morning session with welcoming remarks, which will then be followed by a presentation by CAISO and from the Department of Market Monitoring. From there, we will move into the question-and-answer portion of today's agenda.

The morning will mainly focus on the lessons learned regarding the tariff provisions accepted in the order issued on June 1st and any need to retain them.

The afternoon session will shift the discussion to address any potential longer-term solutions that may be necessary going forward.

We may direct questions to specific participants in order to discover more detailed information to help Commission Staff better understand the relevant issues. Time permitting, we will open the floor for questions and comments to the topics discussed in today's agenda at the microphone located in the center aisle.

Although members of the public are invited to participate in the conference by asking questions after the floor is opened, actions that purposely interfere or attempt to interfere with the commencement or conducting of the conference or inhibit the audience's ability to observe or listen, including attempts by audience members to address the Commission while the conference is in progress, are not permitted. Any persons engaging in such behavior will be asked to leave the building. Anyone who refuses to leave voluntarily will be escorted from the building.

Please note that this conference is not for the purpose of discussing any specific cases. Thus, participants should refrain from discussing the specifics of any cases pending before the Commission to avoid any ex parte concerns.

Also, this conference is on the record, which will be both Webcast and transcribed.

We would like to note that this is a Staff-led conference and that we, as Staff, do not speak for the Commission. Anything said by Staff today does not necessarily represent the positions held by the Commission.

We do have a lot of ground to cover today in a relatively short amount of time. So with that in mind, we ask that you please do your best to keep your responses brief and concise. If the discussion begins to stray beyond the scope of the question posed, we may interject or ask permission to please curtail your comments to bring the discussion back on topic.

I have a few housekeeping matters before we get started today. First, please do not bring any food or drink into the Commission meeting room other than bottled water. Please turn off your cell phones and any other noisemaking devices that you may have on your person. There are restrooms and water fountains located on either side of the building behind the elevator banks, for those of you who have not been here before.

And lastly, we will be here for a long time. So please do take the opportunity to get up as you need to.

For participants here at the table with me table today, if you would like to be recognized to speak in response to questions or comments said by another speaker, please place your tent card up on its side like so, and I will make note of that.

When you are speaking into -- when it is your turn to speak, please do speak into the microphone, and make sure that it is on. And when you are not speaking, please do take the opportunity to turn it off to reduce any background noise. Lastly, while this may be difficult to do, for myself and for others here today, please do your best to limit the use of acronyms and abbreviations.

With that, I would like to turn to Commissioner LaFleur for some welcoming remarks. Thank you.

COMMISSIONER LA FLEUR: Thank you very much, Virginia. I know my colleagues and I will be in and out over of the course of the day, but I am happy to do the welcome.

I want to start by thanking the Staff team for pulling together the conference. I think it's an ambitious agenda and also an inclusive format, and I'm hoping it will be a very productive day. I also want to thank all of the participants who traveled, not surprisingly in many cases, from the West Coast on Friday to come out here, and we very much appreciate your being a part of this.

It's, obviously, a very important topic. It doesn't seem possible that a whole summer has elapsed since we sat at Commission meeting with people from different parts of the California government and CAISO and talked about the summer ahead. We've, obviously, been watching closely what was a very -- in my mind, the summer worked well, but I know it took a lot of coordination and monitoring to make that happen.

What I'm most interested in getting out of today is where we go from here, both in the short term and long term, and from a narrow perspective, what, if any, action will be required of FERC, our Commission, to get there, either in terms of market operations and rules, gas/electric coordination, reliability, or anything else, whether anyone has any specific suggestions or whether we will have to distill that from what we here. But obviously, in order to understand where we're going, we need to understand the larger context and where we've been, and I know that's where we're going to start.

I will be here as much as I can. I know my colleagues will be in and out, too. Thank you very much.

MS. CASTRO: Thank you, Commissioner LaFleur.

Now we can get started with the agenda with today's presentations that we have prepared.

(Audience disruption.)

MS. CASTRO: Thank you.

We will proceed with today's agenda for the two presentations we have prepared today from Mr. Rothleder from CAISO.

Thank you for coming, as well as Mr. Collins, from the Department of Market Monitoring at CAISO.

But just before we begin the presentations today, if we could just take a quick opportunity for the CAISO and the California Energy Commission Staff to introduce themselves, beginning with Mr. Kevin Barker. Thank you.

MR. BARKER: Thank you, Ms. Castro. My name is Kevin Barker, chief of staff for Chairman Bob Weisenmiller at the California Energy Commission. Thank you for having me.

MS. COLBERT: Yes. Thank you. This is Cathleen Colbert. I'm a senior market design and regulatory policy developer in the market and infrastructure policy group at the Cal ISO.

MS. MANNHEIM: Good morning. My name is Sidney Mannheim. I'm an assistant general counsel at the California ISO.

MR. COLLINS: Good morning. I'm Keith Collins, manager of Market Monitoring reporting at the Department of Market Monitoring in Cal ISO.

MR. ROTHLEDER: Good morning. I am Mark Rothleder. I'm the vice president of market quality, renewable integration at the California ISO. Thank you.

MS. MC KENNA: Good morning. I'm Anna McKenna. I'm also assistant general counsel at the California ISO and regulatory.

MR. SUBAKTI: Good morning. I'm Dede Subakti, director of operations and engineering services with California ISO.

MS. CASTRO: Thank you all, and we welcome you for coming here and joining us today.

We will begin with the presentation from Mr. Mark Rothleder.

And if we can, please, queue up the PowerPoint presentations.

MR. ROTHLEDER: Thank you. I want to thank the Commission for convening this meeting. It's an important topic to California and the West. And what I'm going to do this morning is provide you a brief overview of the results of the winter assessment, the upcoming winter, and then I'm going to just briefly go over how the summer played out and some of the things that worked well, and we'll highlight those things.

So in terms of the winter assessment, I want to point out a couple of things in comparison to the winter and the summer. With regards to the gas system, SoCalGas system, the maximum gas demand is actually during the winter condition. Their what's called one-in-10-year gas demand is about 5.2 billion cubic feet. What's different about the winter versus the summer is that, while electric generation accounts for approximately 60 percent of the gas demand in the summer, it actually only accounts for about 20 percent of the gas demand in the winter.

So to be more specific, the electric generation demand in the summer is about 2 billion cubic feet; in the winter, it's about 1 billion cubic feet.

So the -- what we did in the winter assessment was we assessed what the ability of the gas system to support effectively one-in-10 gas demand was. Was it able to provide deliverability of 5.2 billion cubic feet.

From that analysis, we then went on to analyze if the gas system was not able to deliver 5.2 billion cubic feet, what would be the implications for the electric system in terms of potential electric reliability issues downstream.

So through the analysis, including hydraulic analysis that was performed by Southern Cal Gas -- by the way, this report is similar to the summer report. It was a joint report by the California Energy Commission, California Public Utilities Commission, LADWP, ISO, and in consultation on the hydraulic analysis from Southern Cal Gas.

Effectively, what the analysis indicated was that, first off, the one-in-10 design day level of gas demand could not be supported. So 5.2 billion cubic feet could not be supported without Aliso Canyon availability. What the analysis then went on to determine was that, assuming 100 percent utilization of the rest of the infrastructure, the pipeline infrastructure as well as the remaining gas storage facilities, about 4.7 billion cubic feet could be delivered through the Southern Cal Gas System. That assumes 100 percent utilization. Okay? That 100 percent utilization is unrealistic in the terms of actual utilization of the system.

So we went through some additional analysis, said what if some of the remaining facilities' infrastructure was unavailable, such as .2 billion cubic feet flowing reduction because of, for example, a line 3000 work, which is anticipated to potentially occur during the winter. That will bring you down to about 4.5 billion cubic feet. What if were not -- what if you didn't have 100 percent utilization and something more realistic, in the 85 percent utilization range. That would bring you to about 4.2 billion cubic feet.

So it's clear that there's a -- it does not meet the design criteria without Aliso Canyon. That said, what we then looked at is whether, if we ended up having to curtail or if there was a gas curtailment during the -- during a high gas demand day, which is going to be a very cold day in the winter, what would be the implications for the electric system.

So from that perspective, the -- as I indicated earlier, the electric system demand is not as high as it is in the summer. And what we looked at is what is the minimum amount of generation that's needed to maintain reliability in the local areas and in Southern California, across the Southern California area more broadly.

What we determined is that while our gas -- electric/gas generation demand can be as high as about 1 billion cubic feet, the minimum for reliability purposes is somewhere in the neighborhood of about .1 or 100 million cubic feet of demand.

And that's -- that gets into the point where you have some minimum generation on for local reliability criteria. Some of that may be for -- in case you need to ramp up generation in the area.

What that does illustrate is that you have then about 900 million cubic feet of ability, if you were -- let's say if you were economically dispatched to 1 billion cubic feet, you would have about 900 million cubic feet of room to absorb before you got into electric reliability risk.

So what we determined was that, based on the information or based on the gas analysis is it looks like, in most cases, so long as there is sufficient supply coming into the pipeline system for delivery, it looks like in most cases we would be able to absorb, if there were gas curtailments such that we would not be in jeopardy of having to interrupt electric load to support or accommodate that gas curtailment.

However, if the supply does not get into the system or if the utilization in the system falls below a certain level -- and we estimated that that's about 4.1 billion cubic feet -- if there was a cold day and the electric/gas demand was high enough, we may get to the point where almost all the gas to the electric generation could be curtailed. At that point, we would be in jeopardy of potentially having to interrupt electric load, or alternatively, that's at a point where we would ask for use of withdrawal of some gas from the remaining gas in the Aliso field to mitigate or prevent electric reliability issues.

In terms of what we learned from this is that while the risk may be lower to the electric generation and electric reliability in the winter, there is still a risk to gas curtailments. And we've got to still be prepared for gas curtailments to those electric generators.

And unlike the summer, we may have to absorb large amount of gas curtailment, and in the winter, the question is will we be able to resupply from other electric supply elsewhere outside of the Southern Cal Gas System or further to the west. And what we find is that we generally believe that there will be supply available.

However, the availability of that supply diminishes as you get closer to real-time. And that's why we believe that one of the additional new mitigation measures -- maybe "enhancement" is probably a better term -- is utilizing the constraint capability that we asked for for the summer and enhancing that so that we could use that in the day-ahead time frame, in other words limit the potential amount of gas that we would use on the electric generation in the day-ahead time frame so that it reduces the risk of being able to have to absorb a large gas curtailment in real-time and not being able to find supply to absorb that.

And so if we limit our gas burn closer -- potentially going into a cold day closer to that 100 million cubic feet per day for electric generation, it may not be the most economic solution, it may be more costly, but it would allow us to mitigate the risk of large gas curtailments that we may or may not be able to absorb in real-time.

And so that's what we highlight here with --

(Audience interruption.)

MR. ROTHLEDER: Indeed, our analysis is not based on the assumption that Aliso Canyon was necessarily available. In fact, our analysis was on the assumption that -- what if it continued to be limited for the winter condition. And so these mitigation measures are largely mitigation measures to ensure that we can remain reliable and reliably serve the electric demand, even if the Aliso Canyon were only limitedly available.

That said, the Aliso facility is part -- is an integral part of the energy infrastructure in Southern

California. And while longer term we may be looking for solutions that would reduce our reliance on such a gas storage facility, with the loss of the storage facility or the limited availability of the storage facility that wasn't a planned condition for this summer and winter, we have to be prudent in terms of the mitigation measures that we are undertaking, and we have to still rely on the field for emergency conditions in case the conditions, outages, or higher load conditions materialize and we are -- we need to remain prepared to potentially lean on that gas storage facility to maintain reliability.

With that, I will turn my discussion into how did the summer play out. So I will emphasize that we did anticipate that there was a risk for the summer, though, potentially 14 days of conditions where, if there was a large mismatch -- the risk condition was that if there was a large mismatch of expected gas burn and the actual gas burn, if that was -- if the actual gas burn is greater than 150 million cubic feet greater than what was anticipated, that would put us in a risk condition.

And then if you overlay that with other outages that could have happened, planned and unplanned outages, those conditions created the pattern, if you want to say, of risk that would have potentially led to those high gas curtailments that could have led to electric load interruption.

Fortunately, due to the coordination and some of the mitigation measures that took place this summer, those conditions did not materialize. First off, tighter gas balancing rules implemented by Southern Cal Gas helped ensure that there was sufficient supply put into the gas system to meet demand. The coordination, and I will say unprecedented coordination, between the ISO, Southern Cal Gas, and the LADWP, helped ensure that we were coordinated around outages, the amount of gas needed, and the system conditions at the time. And we provided information to the market through some of the measures provided by FERC to inform the market about these conditions.

And all these things came together to actually ensure that we were able to operate through the summer so far without getting into an electric reliability issue. And I would say there was also a dose of good luck, and the good luck was really the fact that while we had some hot days, we had some fires that affected some of the lines going into the system, the good luck was that on those days we had sufficient gas coming in, and we had anticipated those conditions, and we were able to ride through those without getting into those risk conditions.

And I think that's illustrated well in this next graph. And what this graph illustrates is that the blue line is effectively the difference between our expected day-ahead gas burn and our real-time gas burn in 2015. So if you look at the spikes, there's probably about 10 or 11 spikes there where it's greater than 150 million cubic feet difference. And if that would have played out this year the same way, we would have been in that risk condition. Fortunately, what you can see from the orange line is that some of the measures and the coordination and the advanced planning going into the day, we ended up having very few days where we were even approached 150 million cubic feet difference between the day-ahead and actual real-time burn condition.

Now, you can say here that as a result of that it's no longer centered around zero. So we actually may have gone the other way where we anticipated a gas burn in the day-ahead and we actually didn't burn that much in real-time. But I think that's a better condition and less impactful on reliability than the alternative if we would have had a higher than -- higher burn in real-time.

So this is, I think, a very good illustration of the fact that all the measures put together allowed us to operate the system to be in a more reliable condition.

I mentioned the fires. Well, August 16th was a day where we did have a fire that took out some lines going into Southern California area, L.A. Basin more specifically, and that happened at about 3:00 in the afternoon. And you can see by the circle that, once that happened, we ended up having to actually ramp up generation in the LA area. So at that point you can see how generation, the blue line, actually increased above the day-ahead level. But fortunately, we had some underutilization of the gas up to that point. And so over the day, we actually still had enough gas in the system so that we were able to absorb that increase and handle the fire on the line condition.

This graph here just illustrates that the -- we did have increased amount of low operating flow order, and those low operating flow orders are a new tool that Southern California Gas had in place for this summer, and it was utilized. And those low flow orders and events provide the signal, the price signal and the information to the suppliers that it's -- you should get enough supply in the system, because they're concerned about under -- reduced amount of gas being available for burn. So we see from the green lines that those did occur, and those were a part of the solution.

So in conclusion, the summer actually worked well, actually better than anticipated, and I think all things said, the mitigation measures, the action plans that we had in place and the unprecedented amount of coordination came together to actually ensure that we did operate during the summer. The summer still is not over. We still have a few days, a few weeks left. September is not unusual to have some high load conditions.

Although I will say, our forward-looking forecast indicates we don't see any high-temperature conditions, extreme temperature conditions, at least in the next couple weeks. So we are hopeful that the summer, the balance of the summer will be as uneventful as the earlier summer was.

That said, the winter assessment does indicate there is still remaining risk without Aliso Canyon, and there certainly is risk of gas curtailments affecting the electric generation. However, these risks, we don't expect these risks to manifest themselves as electric load curtailments unless the supply conditions coming into the system where utilization of the gas system is less than anticipated. That can happen. There are conditions that are outside Southern California Gas's control, such as gas freeze-off like we have had in the past years where supply is just plain unavailable or it's redirected elsewhere because of temperature conditions across the system.

And if that were to occur, we still are aware that there is a risk that if the gas supply is insufficient to support the electric generation, the minimum generation, we may still have to rely on Aliso Canyon limited withdrawals to mitigate reliability.

From the perspective of the mitigation measures, many of the mitigation measures will still remain in place for the winter. We will be talking about today some of the mitigation measures specific for the ISO and some of the ones that we think can be retired, some of them that could be refined, and some of the ones that would remain, that we would expect to remain for the winter.

In the longer term, the ISO remains ready from a planning perspective to investigate how Aliso Canyon plays into the longer-term planning of the transmission system and infrastructure, and in that planning process, we will assess whether there's options available to us to reduce our reliance on this storage facility going forward.

With that, I will be prepared to answer any questions. But in the meantime, I think I will hand off the presentation to Keith Collins from our Department of Market Monitoring.

MS. CASTRO: Thank you, Mark. I really appreciate your presentation today.

Keith, right before you begin your presentation, I would like to welcome Commissioner Honorable for joining us today.

Hello, Commissioner Honorable, and also

recognize that she has a few remarks to make.

COMMISSIONER HONORABLE: Thank you, Virginia.

Good morning, everyone. I want to express deep appreciation to each of you and the facilities that you represent for what Mark's described as the unprecedented level of coordination, which was a must. I appreciate the chairman of the California Energy Commission, Chairman Weisenmiller, the California ISO, the CPUC, SoCal Edison, PG&E, LADWP, and a few other acronyms I won't share here.

There are a number of stakeholders that have really, we can tell from the presentation but also from your work to this point, demonstrated your commitment in during your best to ensure reliability. And while I recognize that locally there are a number of concerns other than reliability, which are of importance as well, here our focus is on reliability and what we can do to ensure that the lights stay on, that the reports that you are providing are as promising as they are.

So far, the great impacts of the restricted use of Aliso Canyon storage have not been as severe as originally anticipated. I think we heard some months ago that there could have been as many as 15 days of restrictions or brown outs. And I understand that as of August 22nd no gas had to be withdrawn.

And while we made it through the short term, Mark, I agree with you, that some of that was, indeed, luck. And I think we are gathered here to ensure that we are thinking ahead about how we respond, if we aren't as lucky. And I attribute this in great measure to the hard work of so many of you who have worked so hard to mitigate the impact on consumers, and all along the food chain, from residential consumers to commercial and industrial consumers and others.

And while we have so much of the summer behind us, yes, there are still some days ahead to be watchful of, and also concerns that -- you referenced the fire that took place and other things that may not be anticipated that we need to prepare and plan for.

I look forward in the future to seeing -- learning from what we've done well here and, more importantly, what we at FERC can be helpful to you as you work and plan to address this unprecedented situation.

We also need to make sure that we are planning not only for this particular situation, but, from my viewpoint, how this can be a blueprint for how we respond in similar situations.

So I appreciate the time, and I look forward to hearing additional remarks, as I'm able to stay. I will have staff in the room. Again, thank you for your work, and I look forward to our continued work.

And I last want to thank, but not least, FERC Staff, because you've been riding herd over this for some time, and we will for months ahead. So thank you all.

MS. CASTRO: Thank you, Commissioner Honorable.

Now we will go into Keith Collins' presentation. He's from the Department of Market Monitoring.

MR. COLLINS: Thank you, and good morning. I look forward to the opportunity to speak with you today about the outage of the Aliso Canyon natural gas storage facility and its impacts on the natural gas and electric markets. I will be happy to take your questions at the completion of my presentation and later on during the course of this technical conference.

In summary, while the outage of the Aliso Canyon facility has had some impact on natural gas prices and electric market participant behavior, the overall impact on the gas and electric markets was relatively limited compared to expectations going into the summer. In fact, overall prices were down this summer in both the natural gas and electric markets. My presentation will highlight trends in both natural gas and electric markets, bidding behavior in ISO markets, the effects of bidding behavior on bid cost recovery payments, and finish our assessment of the importance on ISO's interim measures in providing enhanced tools and flexibility to manage the challenges associated with the outage of the Aliso Canyon facility.

Spot market natural gas prices are often the greatest single factor driving the ISO's electricity market prices. Particularly in the summer months, natural gas resources are typically the marginal price-setting resources. As shown in this chart, average next-day natural gas prices this summer at the SoCal Citygate were down about 7 percent overall compared to last year. In comparison, the Henry Hub, which is the national natural gas reference hub, was down by less than 3 percent for the same period. Thus, the decline at the SoCal Citygate was larger than the decline at the Henry Hub.

Meanwhile, prices at surrounding hubs, such as the SoCal border and for Kern River, tended to follow a similar pattern as the SoCal Citygate, and both fell by about 4 percent compared to last summer. Prices at the PG&E Citygate fell by about 7 percent over the same period and were frequently the highest in the region.

However, as highlighted in this chart, the day-to-day changes in natural gas prices at the SoCal Citygate increased noticeably this summer. The solid red line shows the next-day prices at the SoCal Citygate in 2016, while the dashed blue line shows the SoCal Citygate prices for 2015.

It is likely that the outage of the Aliso Canyon storage facility contributed to this volatility in two ways. First, it reduced the flexibility of supply available to meet intraday variations. Second, the loss of injection capability removed additional demand for gas.

One of the Aliso Canyon measures approved for the summer allowed the ISO to update the natural gas price used in the day-ahead market with a weighted average of prices based on trades on the Intercontinental Exchange, also known as ICE, just prior to the day-ahead market run. This would have effectively eliminated the one-day lag in the natural gas prices used -- no, in the ISO day-ahead market. While the ISO was prepared to implement this from a technical perspective on July 6, this change has not yet been implemented since the ISO could not confirm with ICE --

(Audience interruption.)

MS. CASTRO: Please proceed.

MR. COLLINS: Thank you.

While the ISO was prepared to implement this from a technical standpoint on July 6th, this change has not yet been implemented since the ISO could not confirm with ICE that this price would conform with the FERC's policy statement on indexes, as required by the Commission's June 1 order on Aliso Canyon. The top chart on this slide shows a histogram of the differences in trades in the next-day market for the SoCal Citygate compared to the lagged next-day index used in the day-ahead market from June through August. The bottom chart shows a histogram of differences in trade prices in the next-day market compared to an updated price at 8:30 using ICE trades.

Both charts highlight the portion of prices above 110 percent, which is the adder for default energy bids used in mitigation and 125 percent, which is the cap on commitment costs in the day-ahead market.

As shown in these charts, if the ISO had been able to implement this change, the update in next-day prices at 8:30 would have significantly improved the accuracy of natural gas prices used in the day-ahead market, and none of the trade prices would exceed 110 percent of the price used to calculate bid prices.

Another measure that was approved by the Commission's June 1 order was to increase flexibility of incremental energy bids in the real-time market to reflect differences in same-day versus next-day trading. This was done through an adjustment to the natural gas price used in the real-time market. This adjustment, known as a scaler, was set to 125 percent and could have been changed if the ISO observed systemic price differences or market harm. This chart shows a histogram of differences in same-day trades at the SoCal Citygate this summer relative to the next-day gas price index used in the real-time market. The chart includes lines indicating trades above 110 percent, the typical adder for default energy bids, and trades above 125 percent, which represents the energy scaler adder approved in the June 1 order.

In the end, only 0.5 percent of traded volume on ICE exceeded the 125 percent scaler adder at the SoCal Citygate and only 20 percent of the traded volume exceeded the normal 110 percent adder.

Notably, the vast majority of trades above the 110 percent level occurred on days that were the first trading day of the week, which was typically a Monday, as shown in green in the chart. Trade prices on these days are frequently different from gas trades on weekend -- as gas trades on weekend packages for multiple days. This package does not typically reflect the value of gas for just Monday. DMM has found that this has historically resulted in differences between the index used in the ISO market and trading for Mondays. This overall trend existed well before this summer and was not new and did not increase significantly with Aliso Canyon or just at the SoCal Citygate hub. Market Monitoring believes this issue could be addressed in the longer term through market changes to current procedures.

Turning to electric markets, this chart shows that average day-ahead SP15 prices, shown by the solid red line, were slightly lower this summer compared to prices last summer, shown in the dashed blue line. As noted on this chart, days with higher day-ahead prices were correlated with both higher loads, as well as a fire-related outage in addition to natural gas prices.

Overall, day-ahead electric prices at SP15 were down 6 percent this summer, which is very consistent with the 7 percent decline in natural gas prices at the SoCal Citygate and PG&E Citygate hubs. Real-time prices at the SP15 hub were down over 9 percent this summer compared to last summer and were 10 percent lower than day-ahead prices this summer.

These declines occurred through a combination of other changes in the electric market during this period, including the addition of NV Energy to the real-time energy imbalance market, with almost 1,000 megawatts of transfer capacity, a doubling of hydroelectric generation, and a more than 33 percent increase in solar generation this summer.

Thus, prices in both the day-ahead and real-time electric markets were lower overall this summer compared to last summer and tended to follow changes in gas prices and system conditions.

This slide highlights some of the changes in bidding behavior that occurred as a result of the increased bidding flexibility allowed under the June 1 order. In the California ISO markets, participants are limited in their ability to bid in commitment costs up to a certain percent of their estimated costs. For most resources, this limitation is up to 125 percent of their estimated costs. As a part of the approved Aliso Canyon mitigation measures, the ISO increased estimated gas costs in the real-time market for the SoCal Citygate with an adjustment factor, known as a scaler, that was set to 175 percent of the natural gas index price. This increased the range of start-up and minimum load cost bids that market participants could submit to the market.

The pie chart on this slide shows the bidding behavior of minimum load bids for all gas capacity on the SoCalGas systems. The pie chart on the left shows all capacity by bid level, while the smaller pie charts on the right break down the subcategories further by market participant share.

The large pie chart on the left shows that most natural-gas-fired generation on the SoCalGas systems did not use the additional headroom for commitment costs. For instance, in August, about 70 percent of the capacity on the SoCalGas systems did not use the additional headroom for minimum load costs. This is shown in the blue portion of the chart. As shown in red, about 10 percent of the capacity during August bid minimum load costs at or near the cap. As shown in green, the remaining 20 percent of the capacity submitted bids that took advantage of the additional flexibility, but did not do so near the cap.

Of the resources that did incorporate the additional headroom in their bids, most was controlled by one participant. For instance, of the bids at or near the cap, 99 percent was controlled by one participant. The same market participant accounted for 85 percent of the bids that incorporated the additional headroom in their bids, but was not at the cap. Bids for start-up costs followed a similar pattern as shown here for minimum load costs.

The chart on this slide shows the same information presented on the previous slide by scheduling coordinator for each day in the month of August. This chart shows that different participants used the additional bidding flexibility for commitment costs to a widely varying degree and that some participants utilized this flexibility differently from day to day, depending on market conditions.

Market Monitoring has analyzed the impact of this increased bidding flexibility on bid cost recovery payments. We estimate that bid cost recovery payments increased by about $2 million this summer as a result of the increased bidding flexibility. This represented 12 percent of the real-time bid cost recovery payments in July and August. Most of these extra payments were from units committed by exceptional dispatch on a few high-load days when the ISO committed additional capacity for load forecast uncertainty.

In summary, the impacts of the Aliso Canyon storage facility appear relatively low overall so far, even though there were increased day-to-day variability in the natural gas markets. Overall prices in both the ISO's day-ahead and real-time markets were down this summer compared to last summer, reflecting a decline in natural gas prices.

Bidding by market participants indicates that the additional flexibility afforded by the gas price adders have been utilized in varying degrees by different participants. The ISO's Aliso Canyon filing indicates the gas adders could be adjusted based on empirical information and market outcomes.

Going forward, Market Monitoring believes the scalers should continue to be included as a temporary measure to increase bidding flexibility. While there was much initial discussion about whether the adders were high enough, we believe these findings illustrate that, if anything, the scaler adders could potentially be lowered in the future based on observed conditions and market results.

Finally, as the ISO looks forward to the coming winter and next summer period, we believe that there are several protection measures that will need to be carried forward.

For instance, to the extent that the gas constraint provisions are extended, we believe it is important to retain the ISO's ability to suspend virtual bidding and to deem constraints uncompetitive and, therefore, subject to energy bid mitigation to account for gas constraints imposed by the ISO. Moreover, we also believe the ISO should consider applying mitigation to exceptional dispatches that are used to manage localized gas constraints.

I thank you for your time and look forward to your questions and our discussion later today.

MS. CASTRO: Thank you, Keith and Mark, for both of your presentations.

I would like to ask whether any of the Commissioners have any questions in follow-up to the presentations?

COMMISSIONER LA FLEUR: No, I have no questions.

CHAIRMAN BAY: I don't either.

MS. CASTRO: Thank you.

Anyone from Staff?

All right. We will proceed into agenda -- Saeed has a question.

MR. FARROKHPAY: Thank you for the presentation. Keith, the information that you show on page 8, the use of the scaler in the bidding, does that have any correlation to what Mark had on his page 8 of his presentation on the OFOs? Essentially, I'm asking, are the market participants using the scaler when there are OFOs or independent of those?

MR. COLLINS: So I think your question is, as the conditions change, whether there was OFOs or market conditions, did participants use the scaler differently during those periods. And I think what we found, if anything, there was a bit of an inverse relationship overall in that, in some cases, certain participants would tend to have higher bids on days where conditions were a little more -- more stable. And then on days where expected high demand was in place, we tended to see a decrease in how some participants were doing that. And so -- and I think as the chart on page 8 that you were referencing shows, I think depending on the participant, there is a different flavor in terms of how the participant participated during those periods.

MS. CASTRO: Thank you. I recognize that Pat Schaub from Office of Enforcement has a question as well.

MS. SCHAUB: Following up on Saeed's question, to take his question and make it a little broader -- he specifically referenced the OFOs.

For participants that were bidding high, were they reflecting any other gas market trend, such as the Monday phenomena you noted or a period of higher volatility or anything else that might relate?

MR. COLLINS: This is a good question, and I think there's a distinction between the commitment costs and the energy bids. And I think that in the energy bid element, typically on days where there were some high loads or higher gas price trades, we did tend to see energy bids reflect those. But in the commitment costs, it tended to be, as I noted, more of an inverse relationship. And from a gas price perspective, the gas prices would sometimes anticipate the conditions or anticipate an OFO condition, and so prices would tend to move during those periods. And so next-day gas prices tended to move up as well. And so that would have been incorporated in the day-ahead market. And the same-day market tended not to be as variable, except for those Mondays.

And so the OFOs were included in the expectations, even in the next-day trading before the real-time markets.

MS. SCHAUB: Thank you.

MS. CASTRO: Okay. Thank you.

With that, we will proceed to today's agenda, item number 1.

MR. REICH: Good morning. I think the first item, how successful CAISO has been in managing the electric system in the absence of Aliso Canyon, is if the metrics are keeping the lights on and prices remaining constant, things have worked out very well. But taking into account that it's been a pretty decent summer temperaturewise, how effective do you think, or ranking them, was your ability to coordinate with the gas pipelines in managing conditions this summer?

And in thinking of that, could you walk us through a typical day and week of coordination with what you do with them, the gas pipelines.

MR. ROTHLEDER: I will take the start of that answer. So going into -- before Aliso Canyon, we had already undertaken more coordination with the gas companies. We had already started sharing information about expected gas burn coming out of the day-ahead market. We were starting to do more regular calls in terms of comparing outages and such.

I think with Aliso Canyon, what stepped up was the frequency and the level of information and the responsiveness to that information that occurred as a result of Aliso Canyon.

So in that regard, we have now moved to not just a day-ahead comparison and discussion about expected gas burns, but we're doing that two days in advance. And we actually are sharing the two-day-ahead, not gas burn, but expected schedules with the market. So going into the day-ahead market, there's more information about, one, forecasted conditions, expected gas burn with coordination between the gas companies and the ISO, and also now expected schedules that may manifest themselves in the ultimate day-ahead market.

And I think those things kind of came together to help ensure that there was a better day-ahead schedule based on now better forecast conditions.

In terms of outage planning, there was a increased amount of information and discussion about outages, planned outages that were occurring on the gas system, outages that were occurring on the electric system. And that increased coordination allowed us to coordinate in a way that if we needed to push an outage off or the gas company could defer an outage because it coincided with a outage on the electric system, it afforded the ability to do that.

And I think just the awareness of the situation, we were much more cognizant about which outages we would take and defer. And when we took those outages, did we -- was it at a time when there was conditions that we actually called for restricted maintenance at the same time.

Under peak-day conditions, we stepped all this coordination up one more level, and on peak-day conditions, we held peak-day calls. We would have peak-day discussions, both in day-ahead and real-time with the gas company. And those, again, allowed us to in real-time determine if there were issues arising that needed to be addressed. And on some of the days, we found that there were -- our awareness of things like a gas curtailment watch, did heighten our alert of potential issues. And on some days, we took action on those gas curtailment watches to actually mitigate potential risks continuing on the next day.

And some of those were not related to Aliso Canyon. We had some situations where there were gas curtailment watches into the San Diego area because of conditions. In those particular cases, while we didn't use the tools about some of the nomogram constraints because we felt it wasn't Aliso related at the time, we did use some of our existing tools including exceptional dispatch. And those tools allowed us to reduce the gas burn, allowed the gas company to return pressures to normal levels at the end of the day so that they were then prepared for the next day, which we believe our intent was to reduce the risk of actual gas curtailments occurring the next day.

So we took proactive action on some of this information to be preventive of more broader implications of gas curtailments going forward.

So that's the kind of level of coordination. And I should say, when I talk about coordination between Southern Cal Gas and the ISO, I really should be saying -- it's really a three-way discussion between Southern Cal Gas, LADWP, and the ISO, because the LADWP is also a balancing area relying on gas from the Southern Cal Gas delivery system.

And I think you will hear today, too, about we tried to increase our information flow to the market participants, the scheduling coordinators. I think you will hear today that there were some improvements in the level of coordination and the information flow, but I think you're also going to hear that there's room for further improvement in terms of information that they were getting from the gas company at the same time they were getting from the ISO.

And I would agree there are continuing rooms for improvement as we continue our efforts to be more transparent and be responsive and coordinate with each other.

MR. REICH: Just to follow up with a couple of points. One of your slides on page 7 where you had the transmission line outage and you showed how you were able to meet that real-time and had the comparison of the two-day-ahead and one day-ahead gas burns, one of the features that we approved was your ability to provide information two days in advance of the market run of scheduling coordinators' anticipated schedule.

Now, this slide is one day, but it looks like the two-day-ahead and the one-day-ahead gas burns match up fairly close. Is that a trend that you've seen throughout the summer? So I guess I'm looking at how effective has that -- your two-day-ahead forecast been to match up with the one-day-ahead?

MR. ROTHLEDER: We were concerned, and there was some feedback concern about whether the two-day-ahead would be adequate to inform the market. I think what we found was overlaid with improved forecasts, just generally improved forecasts during the summer, we found that the D plus 2, two-day-ahead, sorry, information did trend fairly well with the actual day-ahead. If we had forecast errors, the forecast errors did increase as you looked two days out.

I think this year, being cognizant of the conditions, I think we found our forecast improvements did occur. Part of that was because the temperature forecast actually materialized as expected as well. So it's not just our forecast. It's the underlying temperature forecasts that we're also dependent on.

MR. REICH: I guess out of the measures that we have approved, if any one in particular stood out as a big success?

MR. ROTHLEDER: That's a good question, and it's a little bit hard to answer because I know some of the measures you approved ultimately were not utilized for the summer, but we still believe that they're very important. Even though we didn't use some of the nomogram constraints, we stand ready and, in fact, nomogram constraints are in our system, and we believe that had we needed those, those would have been an important measure, even though they didn't end up being used.

I think this D -- the two-day-ahead information flow was helpful. We received feedback from market participants that it was helpful. And I think the role of the ability to bid up to the scaler quantities, I think it did contribute to what I showed earlier as being one of the factors that allowed the real-time gas burns to actually come in less or close to the day-ahead than in the past years. It's one factor. It's not the only factor. There are other factors, I think, that contribute to that, including improved forecasting. Some of the two-day-ahead information probably got overlaid with the OFOs, got day-ahead schedules lined up better.

But I think as Keith Collins indicated, the energy imbalance market is a new tool into Southern California through Nevada Energy, and I think that contributed to the ability to it having, at least in real-time, additional supply capability that helped to reduce the need to increase supply in the Southern California area in real-time.

So I think the -- it's hard to point to any one of them, but I think the suite of solutions that were provided to us provided us a good measure to maintain reliability. Even though some of them may not have been used, I think we learned from setting them up, and I think they will be potentially useful going into the winter when conditions are different. Maybe we're going to have to be more responsive to gas curtailment, even though we're not affected on the reliability side as much.

I don't know if anybody wants to add anything to this.

MS. CASTRO: Thank you.

I have two follow-up questions from Staff, first from Saeed and then with Kate.

MR. FARROKHPAY: With regard to the chart on page 7, it looks like there's pretty good tracking of two-day-ahead and day-ahead overall for Southern California generation fleet. Do you have a sense of how well this works for individual scheduling coordinators? The information that you give them, do you think they find it helpful in gas procurement?

MR. ROTHLEDER: I've heard anecdotally that they did find it helpful. Maybe during comment period, some of them can respond to that more directly.

MS. HOKE: My question is closely related to Saeed's follow-up question. You mentioned room for improvement specifically with information sharing with market participants. And I was wondering if that related primarily to accuracy of forecasts or whether there were other areas of perceived shortcomings?

MR. ROTHLEDER: It's more related to consistency of information that is coming from the gas company and the ISO. And so when we got into particular days where we took a proactive action to reduce generation, to be responsive to some of the gas curtailment watches, I think there was some confusion whether that was a gas curtailment condition, was it the ISO taking proactive action, why did we not use some of our tools, and then the gas company indicating that well, we're not in a gas curtailment situation, what's going on.

So some of those messages that they're hearing, I think they had some confusion about what was really going on, and I think their request would be well, they would be actually a part of the active discussions when those are occurring.

I think we can certainly try to explore those ideas, but I think we feel at this point it's important that the gas company and the operators are coordinated, and we're trying to provide clear instructions to the resources with as much information that we can about why we're doing those -- taking those measures.

Again, there's room for improvement on that.

MR. REICH: Going back to your slide 6, Mark, where you talked about the coordination and the advanced planning, this is more or less just a general curiosity thing than anything else. In the instances where you had a large difference between the day-ahead -- you've forecasted much more day-ahead burn than real-time actually turned out. How did CAISO manage that?

MR. ROTHLEDER: I think, again, four factors. One is the underlying forecasted conditions. The temperature conditions were easier to forecast. There was less air this year than in past years. I think we also took active measures to ensure that we had -- we went to a -- when we had these hot temperature days, that we went to a higher confidence level forecast, and so that we reduced that risk of potentially having a large real-time gas burn higher than the day-ahead.

I think the two-day-ahead information about that forecast, and I think we were -- we had active calls with all market participants about the conditions leading up to that first June 19-20 heat wave. We were on the phone. We were out five days in advance indicating that we have this heat wave coming through, we're very concerned, and we prepared for using our flex alerts, which we did use. We used our demand response, which allowed us to temper off the load in real-time. All those things and advance information and active tools that we used at that point helped contribute to the real-time ultimately not being as high of a gas burn than had been expected.

I will say that just because we were successful in that, I can tell you that, in past history, there are days where you miss forecasts, and it's not unusual to, in the summer, if you have a 2- to 3-degree missed forecast, you have a significantly higher load, especially in Southern California during those conditions. That kind of illustrates where like in 2015 you had some missed forecasts on those days and you had significantly higher gas burns than what you had anticipated day-ahead.

And so while what was a success this summer, I don't want to get complacent that we're always going to be that lucky and successful in forecasting. Forecasting is an art, and there are misses. And we follow temperatures closely, and the weather services are not always accurate, and it's not unusual to have a 2- to 3-degree miss. Once you miss it in real-time, there's no going back. You're stuck in that position.

MR. REICH: Other than the measures that we've accepted, how much demand -- how much has demand response been a help? Like for instance, on a peak day, what your megawatt level curtailment might be and how often it's been called upon.

MR. ROTHLEDER: There are a few days we activated both flex alert and then also demand response kicked in. When we did do those, there was about 1,000 megawatts of demand response, demand response and responsiveness to the flex alerts on the ISO system. And I think from DWP's perspective, they also had similar -- not similar, but as a percentage of their load demand response.

Again, some of those demand response was new demand response that was brought on specifically for this summer.

And I think also the fact that we worked with local officials, the mayor's office, there was a significant more awareness of this condition and what the public needed to do. And I think in response to that, when we did the flex alert, there was much more opportunity for public responsiveness to kick in, and I think that actually helped contribute to this as well.

MS. CASTRO: We have a follow-up from Pat.

MS. SCHAUB: This gets to the constraints, the gas constraint versus exceptional dispatch. I'm just wondering if you ever use the constraint and, if not, why -- what were your thought processes and your analytics in terms of when and why to use it versus exceptional dispatch?

MR. ROTHLEDER: I'm going to defer to Dede Subakti to answer that.

MR. SUBAKTI: There were a couple instances.

The first instance that occurred was in June 19. This was a situation where the SoCalGas System, company at that time, did not issue a curtailment watch. And they called and communicated to the real-time desk and asked for help to avoid a potential curtailment in the electric generator, specifically in two resources. And at that day, an area of the day on June 19, it was fairly limited to specific -- two resources. It was not a regional-wide condition, and it was specifically due to a failure in the

Blythe compressor that support the Southern Cal Gas System.

At that day, we did use exceptional dispatch instead of using the normal ground constraint because we felt that the number of resources were much smaller, and it was actually -- later on after the coordination with SoCalGas, right around 8:00 p.m. that day, they did notice that that was a gas curtailment. We would talk about potential confusions with what is electric curtailment and gas curtailment. But that day, it was really a gas curtailment from SoCalGas, and they did post it on their on ENVOY system.

The other two days were July 21st and July 22nd. On July 21st, we did have -- work with SoCalGas, and SoCalGas did issue a curtailment watch. In that case, the ISO operator chose not to use the max gen constraint because we were under the impression that if Aliso could not have been -- could not have mitigated the issue, then we didn't quite have the authority to use the constraint. We were not sure about that, and there was little time to explore that option. So the operators took the necessary action to ensure reliable operation.

So really, there was uncertainty there. There's also uncertainty whether -- you know, how long that's going to happen. So we did exceptional dispatch during that day in the anticipation to allow the gas system to recover its pressure, hoping that we don't get into an actual curtailment the following day, which is the July 22nd.

So when it came to July 22nd, we have the discussion again at 8:30 in the morning, and we notify our market participants that we are still in the -- SoCalGas still has the issue of curtailment watch, and it was -- we continued the exceptional dispatch. We canceled a unit testing. There was a unit that was on testing in the area. We canceled that. We had the discussion with the SoCalGas, and they did indicate that the L.A. Basin gas pressures were actually okay.

So at that day, we also did not use the nomogram, and we, I think at least after coordination with SoCalGas, we reduce all the exceptional dispatch by around noon, release everything around noon in there.

I think just to answer your questions really, we -- and the operator, we had little time to explore, to figure out whether or not we actually had the authority and applicability of using nomogram that was approved through the Aliso Canyon proceeding for an item that was not quite related to Aliso Canyon.

MS. CASTRO: Thank you.

I would like to recognize Dave.

MR. REICH: I'm going to put CAISO's lawyers on the spot to follow up with that as to, I guess, what your thinking was as to why you couldn't use the nomogram.

MS. MC KENNA: So this is Anna McKenna. I will address that question. The thinking at the time was really conducted mostly by the operators. Lawyers were really not involved at that point in real-time as they were exploring options of how to deal with minimizing potential curtailments the next day and trying to manage the gas burn. When the operator was acting at that time, he was acting under his own impressions and what he knew at that time. It was early in our process as well.

After the fact, we did have discussions about when we could actually implement the max gen constraint. And we think in that scenario we probably could have, and we do certainly feel we have, the authority to do so. There doesn't have to be a direct relationship to Aliso. We do feel that as long as it's directly related to the SoCal system and the constraints in that area, the SDG&E system, there would have been authority to enforce that constraint.

And therefore, going forward, we have trained and have talked through these issues and do believe that -- going forward we believe we have the authority to do so if needed.

And again, as Dede pointed out, in this case it was a short time period, little time to explore those issues. After the actions were taken, we had some conversations and highlighted that, perhaps, we should rethink this going forward and make sure we have the tools that we need to act swiftly.

MS. CASTRO: I would like to recognize Kate.

MS. HOKE: I'm jumping ahead in our agenda a little bit, but I think the discussion is leading to this point right now. Clearly, there was a bit of uncertainty from an operational perspective about when the gas constraint could be used. And I know you haven't used the authority to either suspend virtual bidding or to reserve the internal transfer capacity.

But I'm just wondering to what extent you may have developed any sort of guidelines or implementation details in the business practice manuals to provide some clarity and predictability about when and how these tools might be used?

MS. MC KENNA: I will take that question again. This is Anna again. I think in terms of that particular scenario, it certainly taught us all some lessons, and we do want to enhance our business practice manuals, as well as we enhanced our own procedures internally to make sure we have the knowledge spread uniformly across our operators. So that's been taken care of from an internal perspective.

Prior to go live, we did actually enhance our BPMs as best we could based on the knowledge we had at the time as to how these procedures would take effect. We added two addendums to our business practice manuals for market instruments and market operations, through which we described how we would conduct these measures. With the lessons learned over the summer and some of the testing we've done additionally since then, we do want to enhance those further as we go forward into the winter. As we mentioned, we intend to actually modify some of the authority we ask for, particularly the authority on conforming the transmission limits. We would like -- and the paths. We would like to have some -- we would like to retire that one specifically.

With regards to the virtual bidding, we always -- we were tied -- virtual bidding, our suspension of virtual bidding was tied to when we enforce a constraint or conform the limits with the retirement of the conforming of the limits, of course that goes away. But because we intend to do max gen constraints still going forward -- we haven't had the opportunity to really understand exactly how that would work and what conditions would lead us into a market issue that would require us to suspend virtual bidding, but we will take the time and opportunity to put more detail going forward as much as we can. As you all know, we did this in a fairly expedited process. So we haven't had too much time or opportunity to exercise some of these tools.

MS. CASTRO: Thank you, Anna. I do want to bring the conversation back to agenda item 2 to make sure we've covered everything with that and recognize Dave.

MR. REICH: This one seems pretty straightforward, what's left of the items that we've approved. Has anything you have had the opportunity to actually use worked out as planned, or were there any unintended consequences that you might want to rethink going forward?

MS. MC KENNA: This is Anna, and you're getting an answer from a lawyer on this one, not a operator or market operations person. In terms of the overall -- and Mark stressed this earlier. We do believe that the totality of the measures as well as the actions we took with coordination really helped us deal with the issues over the summer and prevent a lot of issues that could have otherwise led us to where we were thinking of going with the 14-day disruptions, but it could have happened. So we think we're successful with that. It's really in terms of, you know, why we're thinking, for example, of retiring the constraint conformance that we asked for, it has to do a lot with our ability to actually explore further in our operational procedures with peak reliability. We have the ability to manage that transmission limit better in emergencies, and we will talk about that a little bit later today.

But I think that from an overall perspective, it's really difficult for us to say which one acted the best and which one had the most effectiveness, but we do believe that the totality of these were helpful. And that's why going forward we plan on asking for authority for most of these.

But that said, we also learned some lessons, and we want to modify some of that. I think we will have an opportunity to talk to that later.

MS. CASTRO: Thank you, Anna.

I think we're going to go on to item number 3.

MR. PHUNG: Given the limited availability of Aliso Canyon and the anticipated or unanticipated conditions that have been experienced this past summer, what has been the greatest challenge in being able to maintain reliability?

MR. ROTHLEDER: I think probably the greatest challenge of maintaining the reliability, in my mind, is the forecasting and anticipating the conditions that are going to arise. So in some cases, what we expected to occur and what we prepared for didn't materialize, but as

Dede indicated, there are some things that we didn't anticipate that did occur that didn't fit the exact mold of what we set these provisions to do, and that kind of threw us off a little bit in terms of what tools we could use or not use.

But I think from a reliability perspective, we certainly used the tools that we thought we had in terms of including exceptional dispatch.

I think the other thing is that we didn't know how things were going to play out for the summer. This is the first summer we've had this condition where we haven't had Aliso Canyon. It's a different operating paradigm for the ISO. It's a different operating paradigm for the gas company. And it's a different paradigm for basically users of the gas system. So how they purchase gas and how they use the other storage fields and their strategies had to adapt. And we weren't quite sure, frankly, how those adaptation were going to manifest themselves in terms of behavior and whether the things like the OFO were going to be effective, how effective they were going to be.

So there just frankly was a lot of uncertainty about how all the, not just the provisions in our tariff changed, but just the overall suite of changes were going to play out. And we kind of learned as we went through the summer how they did play out, and we got more and more confident in some of those tools, including the OFOs and such.

I think going into the winter we have now a much better appreciation for how these will work. Some of these provisions, such as the OFO, will have been asked to be extended.

But I also want to say that the winter is different, and I tried to describe that earlier in my opening comments, that the winter being the peak conditions for the gas company and susceptibility to supply limitations because -- outside the Southern Cal Gas System, we need to be prepared for those, even though in the summer those are different conditions. We don't have the high take-out conditions.

So it's just now adapting to those new conditions, those situations that are different in the winter and being prepared for those as they change. So those things. It's just there's a lot of concern about this is a new condition and being prepared for a variety of conditions that we didn't know how they would play out.

MS. MC KENNA: This is Anna. I wanted to add a couple of comments to that response, and I will ask Dede to address -- to give you an example, one of our biggest challenges this summer, which is not unusual over the summer. Heat waves and fires in California are always a challenge.

But I also wanted to take this opportunity, because this is a good time to address this issue, one of the benefits of what we did in the spring and in our expedited but robust stakeholder process with our stakeholders is that we -- and we raised a lot of awareness and ability and discussions with our market participants from the generation side, from the load side.

We actually had an opportunity to really educate ourselves as to what they were expecting and what we were expecting, and we think that the awareness aspect of all of this and the communications and coordination did actually, you know, contribute to the success of even not having to use the tools in many instances, preventing the curtailments that we could have otherwise seen on the system, in combination with the OFOs by the gas companies which led to more tightly managed systems on the gas systems. Those all together allowed us to prevent some of the challenges over the summer you would see otherwise.

We did have an interesting time from the fire perspective. And we want to share with you how we dealt with it and some of the coordination with the gas companies.

MR. SUBAKTI: This is Dede. There were normal challenges, I would say, in summer in California, the first one being the heat wave. I really appreciate the work that my colleague and team is doing with their ability to forecast heat wave. It's very -- it's an art, but Mark's team did it very well.

During those heat wave situations, because of the coordination that we have, not just within ISO but also with SoCalGas, the neighboring BA, I think earlier Mark talked about the peak-day call. We see that -- by the way, we normally do two types of peak-day call, one with the market participant and one with the reliability only. That actually allows a lot of coordination. And in those peak days where we have the heat wave, I literally saw unprecedented coordinations among scheduling coordinators, gas company, the gas suppliers that the gas comes out strong in the system. The day-ahead market schedule come out strong in the system.

Those are really, really good and presented a lot of coordinations, just being able to prepare for the heat wave. The transmission owners responded to restricted maintenance operations mode. Everybody's played a very good role in those heat waves.

Anna talked about the fire. We had one of the largest fire in the L.A. Basin with the Blue Cut fire. I believe that was August 16. We actually lost three 500-kV line into -- that serve L.A. Basin. There were not --

there's not that many 500-kV line that serve L.A. Basin, and we lost all three of them.

It was challenging, but what's kind of interesting about that is there was, again, a heightened, unprecedented coordinations between our operators and the SoCalGas operators here. It was very good. We called them. We talked to them and explained the situation, that we had fire, we needed pretty much all the generation that we have, that we had that day, all the generations would commit, all the resources committed, you know, because that was a forced outage.

So there was no flex alert in front of it, because we didn't know that we were going to have all these lines out. But the participating demand response even in the market -- you know, we have the PDR, participating demand response in the market, were also committed and dispatched in the market, and it allows us to go through that day. We did burn more gas, and we did coordinate that with SoCalGas, and I believe SoCalGas actually were able to pull gas that was needed from the remaining Playa del Rey and Honor Rancho storage fields that day. That was my understanding.

So very unique situation with the Blue Cut fire. It was very challenging, but I did see a very good coordination that allows us to pull through the day.

MS. CASTRO: Thank you, Mark, Anna, and Dede for your comments. I'd also like to recognize that Alan Phung is from the Office of Energy Markets -- Office of Electric Reliability.

I think we would like to move on to the next agenda item.

MR. ELLSWORTH: This question is actually for Keith, and it has to do with gas and power prices and markets in general. In your great presentation, you did show there actually -- prices are relatively low and gas prices fell, and I think power prices were low in the previous year. The volatility was up.

Could you just describe what you think the main causes of those low prices were? Was it just due to low gas prices in the U.S. in general? Was it due to greater electric gas coordination going on in Southern California? And also, were there any particular periods of stress in the gas and power markets that caused volatility in gas power prices, particularly in the intraday markets?

MR. COLLINS: Thank you, Chris. I think what struck us as being very interesting is looking at the Henry Hub relative to what we saw in the West. And the Henry Hub was down only a couple percent. When you look even in July and August, it was almost identical this summer compared to last summer. And when you look at the spread, the basis spread between the Southern California region and the Henry Hub, we saw a collapsing of that over the course of the summer and, in particular, at the SoCal Citygate was substantially lower than what we had seen last year and then also lower than what expectations were -- where we were at the beginning of the summer. So by the end of the summer, it was much tighter.

And so it is very difficult, I think, to identify specifically what may have caused that, but we do know that the Aliso Canyon situation has changed the landscape, so to speak, in the gas markets in Southern California. And so we saw periods where the SoCal Citygate and the next-day market was below the Henry Hub, and this, when you look at previous periods, was a bit unusual. And then we saw periods of variability where it would come up higher and even higher than the PG&E Citygate.

So Aliso Canyon is likely -- it appears likely to have had that relationship with it. I'm not sure if -- the particular reasons why it would cause it to be that lower, that much lower. But it was, and it did affect -- the surrounding points were also similar. For instance, Kern River and the SoCal border, points that surround it in the West, tended to follow a similar pattern, but it was most pronounced at the SoCal Citygate.

And then the next part of your question was about stress on markets. And we did see in terms of the higher prices in the next-day markets, there were OFOs during some of those periods, typically with the 5 percent tolerance, either stage I or stage II, stage I was a 25 cent per MMBtu. Stage II was about a dollar per MMBtu.

But what was interesting was the market in a way tended to anticipate some of these changes. And so there were some days that there were no OFOs, but prices may have been a little on the higher side or closer to what they were on days when there were OFOs. And so it definitely changed the paradigm of what we had seen in previous years.

But what was interesting as well is that typically those periods were also correlated with periods of electric -- you know, either high loads on the electric system, the fire. And so there was greater affect on the -- what we were seeing in the electric markets and how that would play out in terms of when the OFOs or when expectations would occur.

And so a good example of this was also during the period we were talking earlier, is mid-August, and we did see prices, both in the next-day markets tend to be a bit higher, and in the same day markets on August 16th was the day where a lot of those prices tended to be higher than the next-day average. And so the markets were reflecting the conditions that were occurring on the system.

MS. CASTRO: Thank you, Keith.

And Chris?

MR. ELLSWORTH: On the intraday market, was there a lot of activity on the intraday gas market?

MR. COLLINS: So there were days where -- and again, particularly days, on a Monday or on days where there was more electric demand, that we did see very good trading activity. And I would say that there were some days where maybe in terms of traded volume, you know, maybe a third or more of the volume that was in the next day. And that's -- in tracking next-day and same-day activity, there's some days where there's maybe a trade or two, but there were some days where there was frequent trades and decent volumes relative to the next day.

MS. CASTRO: Thank you.

I believe we have a follow-up question from Dave.

MR. REICH: Keith, just eyeballing the charts that you presented with gas prices being a bit lower in 2016 than 2015, but electric prices being more or less the same, that to me would imply that there would be either a higher heat rate for those higher energy prices, or -- did you either notice that, or did you see additional mark-up in the energy prices, bids to set that?

MR. COLLINS: So you are correct, there were -- there are periods where -- particularly if you look at peak prices, the implied heat rates were a little bit higher in the day-ahead. When we -- it's difficult to pinpoint exactly how that relationship played out. When we look at the incremental energy bids that market participants were placing in the market, what was interesting was there didn't appear to be a systematic shift in the bidding activity. And we broke things out by bid range and looked at the curve. And as you look at the day-ahead, I think participants were bidding in a range that seemed reflective of something that was normal or typical, as we had seen prior to the Aliso Canyon period.

I do want to make that there was a pretty big distinction between what we saw in the day-ahead market and what we saw in the real-time market. And what we saw -- and this is reflected in some of the prices that I described earlier where the real-time price was 10 percent lower than the day-ahead price, and that's bigger than the difference last year. Last year, it was only 7 percent lower.

And I think it speaks to some of the comments that Mark and others were making earlier in that participants were up to their day-ahead bid. When you go into real-time, they have the ability to rebid their real-time bids. And what we found is that they may -- they tended to bid, perhaps, even lower up until that point. And so -- as a preference to try to burn or use their -- keep to their day-ahead schedule.

Whereas, once you got to the point at which they hit their day-ahead and above incrementally in real-time, we tended to have a different type of bids, which were, perhaps, more of a premium, but that premium didn't really change compared to, let's say, an earlier time period, like May or June before some of the measures were in place.

And so in those periods, what we tended to see was typically when the gas prices would elevate or be higher or there was some same-day trading that was higher, it was during those periods where we saw an uptick in how participants were bidding. It wasn't an overly large, but it definitely followed the trend in what we were seeing in the gas markets and based on the conditions that were occurring on the system. So some of that may have been playing a factor in some of the prices that we were seeing, but I think overall, I think the point that we saw was there just didn't appear to be an overall systematic trend.

MS. CASTRO: Thank you, Keith.

I believe we have a follow-up from Pat.

MS. SCHAUB: I do want to take this into the next question as well because it's sort of all the same.

MS. CASTRO: Yes, please, do.

MS. SCHAUB: The next question -- I think you've covered a lot of it already. One thing you did mention is there were some differences between market participants.

Is there anything you can say about why the different strategies might occur between the market participants?

MR. COLLINS: So there are different types of participants, and we looked at them in terms of are they a net buying participant or are they a net supplying participant. And there can be some differences between those two types of participants.

MS. SCHAUB: Can you explain why?

MR. COLLINS: That's -- so really, what we're saying here is that are you primarily a load-serving entity that has a responsibility to serve load with generation and how they supply that generation into the market versus entities that are primarily suppliers and how they bid into the market. And there are differences in, perhaps, the risks they face, and so their bids reflect that.

MR. REARDON: On the gas cost adders, there was justification given for it at the time that it would be able to separate the resources in Southern California from the resources on the rest of the CAISO system because it would make them less likely to be dispatched for system needs. Was the GAAS cost adder at all effective in doing that in separating the resources in Southern California from those in Northern California?

MR. COLLINS: The answer is it was and it wasn't. The participants that availed themselves of the additional flexibility, in fact, did end up positioning themselves at the higher end of the curve, which would mean that they would be used for more local reasons rather than the system reasons.

But as I noted earlier, that 70 percent of the capacity did not avail of that additional potential headroom. So you end up in a situation where they were on a different part of the supply curve and they stayed in that part of the supply curve. And so those that did take advantage ended up being higher, and those that didn't were in the normal supply curve.

MR. REARDON: Do you think that was simply the result of the lucky conditions this year, or do you think even in a more constrained year this would -- there would still be sort of low utilization of that flexibility?

MR. COLLINS: That could be difficult to say. I think it depended on the strategies of the particular participants that were engaged in the bidding. And I think part of it had to do potentially with expectations of how much gas they were prepared to burn or not burn, and I believe that factored in. And so to the extent that the variability of temperatures or weather factored into that, that could potentially play a role.

MS. CASTRO: Thank you.

I think we can move on to question 6.

MR. REARDON: Question 6, this, I think, relates to the provisions in the settlement that allowed for a waiver of penalties in cases where either the ISO or SoCalGas requested that a certain generator be dispatched for reliability. I know that you mentioned before there were a few cases where SoCalGas did request a few generators be dispatched or turned on.

Did these generators get any relief, or did that even come up? Did they run into penalties?

MR. ROTHLEDER: This is Mark Rothleder. I think we have a representative from Southern Cal Gas who may be in a better position to respond to this. But it's our understanding that there were five times in which the imbalance penalties were waived, and I think there's reasons for those waiver, including the dispatch orders were because of a ISO reliability-based instruction. But if you want more detail, I think we should defer to them.

MR. REARDON: And was there -- so just to clarify, those were all electric-reliability-based or not?

MR. ROTHLEDER: I'm not quite sure, of the five, what was the basis for each individual waiver. Again, I think Southern Cal Gas would be in a better position to answer that.

MR. REARDON: Okay. Thank you.

MS. CASTRO: Thank you, Dennis and Mark. Now we can move on to question number 7 with Chris Ellsworth.

MR. ELLSWORTH: In some respects, you may have already answered this, or SoCalGas may be better able to answer it.

But has it really affected gas prices on SoCalGas's system, San Diego Gas & Electric's system, maybe for other customers, the outage of Aliso Canyon? And also, natural gas prices beyond SoCalGas and San Diego Gas & Electric, any thoughts on that? And that's open to anybody.

MR. COLLINS: So I will just take this a little bit here in terms of our observations of the volatility, our observations on the gas levels, on the systems, and the prices for the hubs and the systems, both inside California and outside California.

And I think, you know, part of what we were describing is yes, it does appear that the increased volatility has occurred in the market side and that the surrounding points could reflect some of those conditions. But I think when you look at the PG&E system, the frequency of OFOs that Mark presented earlier shows that -- so I will summarize. There were 37 percent of the summer days, June through August, had a low OFO, and 18 percent had a high OFO. And compared to Pacific Gas & Electric, they had about 10 low and 10 high during the same period. And so definitely a different set of frequency, but it's also difficult to -- and perhaps some of those representatives can talk to you, you know, what was the -- was one driving the other. I know I can't speak to that, but they weren't always during the same periods. Some days they were; some days they weren't.

MR. ROTHLEDER: I think there's a second piece to this question. It's really -- the question, I think, maybe is also did the condition cause -- even though they may not have manifested themselves in prices, did it change the operating strategies to change the cost of dispatch at all across structure. And I think the answer is probably yes. I'm somewhat speaking here from what I understand LADWP did, because they did change their practices in terms of refraining from doing kind of economic dispatch, economic decisions to reduce their gas burn burden, and they also refrained from longer-term sales. This is some of the measures that they took as a part of the action plan.

I think you would have to ask some of our scheduling coordinators where they took actions to arrange energy in a different way that could have -- maybe didn't manifest themselves in the prices themselves but did cost energy differently.

And I think going forward, I think we do anticipate that if we do need to enforce day-ahead-type nomogram constraints, it could have an impact on what otherwise would have been economic dispatch and commitment. I don't have the quantification how much that would cost or anything like that, but I think there are implications because of the different operating -- the way we have to operate without Aliso.

MS. SCHAUB: This is looking at your surrounding areas, CAISO, both with the EIM and with the imports and exports and implications for your neighboring areas. Have you found any changes as a result of both Aliso and the tools that you've been using in terms of their participation in your markets or their availability to participate in your markets?

MR. ROTHLEDER: I'm not sure we can see a -- any dramatic change, per se. I think what we've seen is -- and maybe it's more expected that on the hot days we did see just a general reduction of imports, electric imports into the system. So the energy stayed kind of at home and wasn't available for export to California.

I don't think that's unexpected, but it certainly is a heightened awareness of the fact that when those imports -- or those energy stay home and are not available for export, it puts more burden on the gas resources and resources in the area. And our assumptions about being able to rely on supply outside the system, then, become more challenging.

MR. COLLINS: I will add, in terms of EIM, what was interesting is even on some of the hot days that Mark was describing, there were periods or hours where the EIM transfers were moving out of the ISO and into the EIM regions and other hours where they were coming in. So it's definitely a balance based on the conditions and the price.

MS. CASTRO: Thank you, Mark and Keith.

We will continue on to agenda item number 8 -- 9, I'm sorry, with OGC.

MS. HOKE: We've mostly covered all of this, but one thing I'm curious about is, in the filing where you guys proposed these interim measures, we heard a little bit about how there could be interplay between virtual bidding activity and the reservation of the internal transfer capability. Whereas, I don't think we heard anything about how that may interact with enforcement of the gas constraints.

So I was wondering if there are any scenarios that you could discuss that could kind of give us an idea about how one may affect the other and how that might be -- come into play.

MR. COLLINS: So with respect to the gas constraints, our concern is ultimately one of unintended consequences. And I think that -- our sense is with the implementation of the gas constraints, there's to be a difference between the pricing node and the generation node, and our sense is if things work out, then virtual bidding shouldn't be affected.

But our concern is the potential for some unintended consequences of the application of the constraint, that either the implementation or the application working in ways that we might not have anticipated. And so I think from that perspective, we're still -- we look at it as a important tool during those periods as well.

MS. HOKE: And then as a follow-up, obviously, the terms "for purposes of economic efficiency" is pretty broad and vague. I wonder if you developed any sort of parameters about what could constitute an economic inefficiency.

MR. ROTHLEDER: I think that's a good question. I think what we anticipated what might happen is that if we started to see the gas constraints being used in real-time but not in day-ahead, would there be virtual activity that would act in anticipation of that happening on a frequent basis. And if those virtual positions did occur, would they undermine the unit commitment and the objective of getting accurate gas burns on physical resources in the day-ahead. Because we didn't have the events where we actually enforced the constraint in real-time, I don't think we ever saw that play out in materials, and that's why we never ended up needing to activate that.

But I think, again, conditions may be different in the winter that we may be still susceptible to that, and I think we would like to maintain the ability to call upon that for efficiency reasons if we find there is that interplay that is undermining the objective of getting accurate physical commitments in the day-ahead.

MR. COLLINS: Just to add to that a little bit, I think part of it is when you introduce a constraint in one market or another market, that can lead to sort of opportunities that virtual bidding can -- it won't actually help the market efficiency, but you can end up creating some economic situations that are unintended.

MS. CASTRO: Thank you for your questions and your responses.

We will be moving on to agenda item number 10 with Saeed.

MR. FARROKHPAY: Here's a difficult one for you. I assume you haven't had to deem any transmission path uncompetitive for the purposes of market mitigation because you haven't invoked the gas nomogram.

But do you have a tool for the operators to determine when to invoke that? If you have the gas constraint actually in force, do they know which -- do they have a table to go to to figure out which paths should be deemed uncompetitive?

MR. SUBAKTI: Yes. Currently in our system, there are -- we use the term gas constraints, and there are actually about seven constraints in there, each one for each different area, and it's one for the whole big Aliso Canyon area. So what the operator does is they have a process and procedures basically that allows us to look at here's the prediction of the day-ahead gas burn, and then here's where the real-time is going to be. And in coordination, we talk about SoCalGas, and we can basically select which one we would like, what we need to use for a certain day. And that's a part of the normal process and procedures, and they have the numbers.

They also have real-time monitors on -- the transmission and generation dispatchers actually have real-time monitors on the actual, so to speak, real-time gas burn. So they can actually see what the implication of what they just did, if they were to use that nomogram in there.

I will probably turn over to Mark and Keith with regard to the market monitor implications of that gas burn.

MR. COLLINS: So the challenge with the -- what is known as the dynamic competitive path assessment, which determines whether or not a constraint is competitive or not, the automated process that works today doesn't take into account any limitation that may occur as a result of the gas constraints. And so it may overestimate at times the amount of relief it might get, but in fact, you may be constrained as a result of that.

And so the Market Monitoring was prepared to review instances where the gas constraints were implemented and how it was affecting other -- how it was interacting and reflecting with other constraints on the system. And then based on this analysis that we would review, we were prepared to deem certain constraints that may appear under the automated approach to be competitive, to deem that uncompetitive, and that would be included in the set of constraints that Dede was talking about in terms of what's competitive or not competitive.

MS. CASTRO: Thank you.

We will continue on to question number 11 with Bahaa from the Office of Energy Policy and Innovation.

MR. SEIREG: I was just wondering if any of the market measures that have been adopted have resulted in issues with settlements or virtual bidding.

MR. ROTHLEDER: I think mainly because we haven't had to bind some of those nomogram constraints, we have not had those situations that translated into disputes. I think the question was around the special provision around the syncing up the C node or the resource-specific price to the point of delivery or the P node price. That's a normal process that happens and syncs up during normal conditions. What we found, because we didn't have -- if we had to enforce the gas nomogram constraint, we would have basically not done that sync up so that the resources themselves were priced consistent with the nomogram constraint. And because we didn't have the nomogram constraint, that didn't occur, and therefore, there was no related issues or disputes related to that.

I think the virtual bids, we've already talked about that. We didn't have to turn off virtual bidding either. So there was no related issues there.

MS. MC KENNA: If I can make a comment with regard to that procedure as well. Even though we never actually had to use it, we did actually implement it both in our settlements system as well as our markets system to be able to switch those prices and make sure the prices were correctly -- and tested it, and so we know we can do it if we needed to. I did verify that we were able and capable to do that.

MS. CASTRO: Thank you.

We will proceed on to item number 12 with Dave.

MR. REICH: Well, I don't want to be charged with animal cruelty in that we've already gone through this one. But is it fair to say that the assumption going forward, that because you won't be looking at the internal transfer capacity reservation, that that will be at least one element that will drop out of your request to continue with the suspension of virtual bids?

MR. ROTHLEDER: There's two questions there, and I have to break it up, if you don't mind. You're right that with the taking -- or limiting the transfer capability from north to south, that was a provision that we asked for, and we think we won't need that provision going forward for the reasons that Dede described earlier about -- or I think Anna described earlier about the fact that we actually have some measures that allow for higher emergency ratings in coordination with the peak reliability coordinator. So we think those provisions are no longer necessary.

However, the need to maintain the ability to turn off virtual bidding was less related to those transfer constraints and potentially related to if we got to the point where we enforced the gas nomogram constraints, we believed that there could be unintended consequences of economic inefficiencies that could be created with virtual bidding, and we would still want to maintain that ability, even though we didn't have to turn it off for the summer so far.

MR. REICH: Just to follow up, Kate had posed a question as to whether you had thought about parameters around economic efficiency. Is that something that you will continue to think about and, perhaps, put in tariff language?

MS. MC KENNA: I will weather that question. Part of the struggle is that we really -- it's something you know it when you see it. I hate to use that expression. But we are trying to avail ourselves of some flexibility so that if we have to suspend it quickly, we don't have to go through too many hoops and procedures and preserve the integrity of the market when we are dealing with these issues.

And some of the scenarios that Keith and Mark referred to, I think those, you know -- we have seen -- we know that there are some possibilities with regard to the day-ahead market pricing, real-time market pricing, lack of convergence. We don't see the convergence yet. We see the inefficiencies resulting in the market. Those are the kinds of things we will be looking at, and we are happy to describe those as the types of scenarios and examples. We don't feel confident that we can prescribe them strictly in our tariff, because that would reduce the flexibility that we need when we need to act quickly.

So that's the push and pull we're faced with here. Perhaps if we had the opportunity to use it over the summer we could have had a little bit more to share with you. It's still in our minds something we would like to leave more in the BPM land. We will try to increase our thoughts on that going forward in the BPMs, but we don't think we will have that in the tariff, at least we will not propose it as such.

MS. CASTRO: Thank you.

I also wanted to ask Kate, because earlier in the discussion we covered a little bit of question number 13, should we go into this one, or we can move on to 14?

Move on? Okay.

At this time we are going to move on to question number 14 of today's agenda with Office of Enforcement.

MR. ELLSWORTH: I think we may have covered some of this material also, but perhaps we can just kind of summarize the issues in this question, and it really is kind of the changes in operations that SoCalGas has had to implement, particularly OFOs, the low and the high OFOs.

How has it impacted your operations? And also, which of the measures from the June 1st order would you say are the most useful in dealing with those?

MR. ROTHLEDER: So I do think that the low OFOs and generally the OFOs are -- were very helpful in incenting, sending the right signal to the purchasers of the gas to get the gas in the system in advance and based on the forecasted conditions. So I think that is, that was and remains a very effective measure.

I think the fact that the frequency of the low OFOs occurring is indication that the operational constraints on the gas system were more significant without Aliso Canyon, and I think there were also some days where you actually had both low OFOs and high OFOs on the same day, which kind of is a -- kind of stretches the mind, but it basically means that you anticipated one thing and you went into it, and you ended up having the opposite. And that illustrates the narrower band of operability that exists on the gas system as a result of not having Aliso Canyon, because Aliso would be able to both absorb high-pressure conditions, you would be able to inject and absorb that, and when you had low-pressure conditions, you would be able to withdraw. So I think it's an illustration of the lack of that tool on the gas system.

From the operation of the electric system, I think, again, the OFOs, again, I think did send the right signal and did help ensure that there was sufficient gas brought on to the system for real-time, and you overlay that with the other measures, and I think it illustrates why we didn't have these large mismatches, which is one of the risk factors in the summer. So I think it is one of the important tools, and it's one of the tools that I believe Southern California Gas has just asked for extension into the winter.

MS. CASTRO: We have some follow-up questions from Staff, with Dave and with Kate.

MS. HOKE: I want to take a step back, back to the business practice manuals. It occurs to me that the way you've been sort of describing these efforts is as more or less a work in progress as you learn from use of any of these tools. So I was wondering sort of the status. Like have you done everything you intended to do up to this point, or are you continuing to refine this as you go through?

MS. MC KENNA: I will take the question first have we done everything we intended to do. We certainly did everything we intended to do by the time we were putting these measures in place this summer. Could we have put more in there? I'm not going to deny we could always have put more in there. But we did what we could based upon what we knew at the time. And we had to get the documents out as soon as possible so market participants could see them, because what's the point of having them at the end of the summer.

But going forward, I was suggesting that going forward, as we go to our next round of tariff enhancements, that -- or extensions and modifications related to this effort, we will take the opportunity again to update the BPMs, based on both the changes we're making -- there will be some differences -- and perhaps any additional examples we can provide or expectations, setting expectations, that we can provide in that regard.

So that is definitely a work in progress with regard to the stuff going forward.

MR. ROTHLEDER: Let me add to that. There was at least one item that we didn't implement. I think we ended up waving off. That was the day-ahead index, the daily update to the index, and I think that's still something that is -- that we would like to do so long as we've got the agreement about the underlying ICE index that we could be using. So Anna, if you want to add to that.

But you're right, there was a learning process, and part of that learning process is that we put in place in the models these constraints, such as the nomogram constraints, and because we had to do this relatively quickly, there was some manual processes if we had to, let's say, shape a real-time gas constraint around the real-time conditions. I think now that we've got a little bit more time and we've tested this out off-line, there's opportunity there to improve and automate, if possible, or reduce the manual intervention in terms of the shaping of the gas constraint.

And so I think we're in a much better position now as we go into the winter, even though we didn't have to use it, that we've now learned off-line through the off-line testing what we need to do to enhance that.

MS. CASTRO: Thank you.

I believe Sidney has some comments.

MS. MANNHEIM: Thank you. This is Sidney Mannheim from the Cal ISO. I just wanted to mention that we've worked very hard on the operating procedure for gas-electric coordination, perhaps more so than on the BPMs. After each event involving coordination with the gas companies, there have been lessons learned, and we've continued to work on the operating procedure. In fact, it took us a while to get it published because we kept learning things and kept adding to it. So that has been an important vehicle for documenting our electric and gas coordination, and we will probably be working on it again soon.

MS. CASTRO: Thank you.

I would like to call on Pat and then Dave for some follow-up questions.

MS. SCHAUB: Thank you. Part of the question and concern was resources' ability to work under tighter balancing conditions. Anything you can share in terms of what the resource experience was or your experience with resources' ability to get gas under the low OFOs and the tighter operating conditions without Aliso Canyon?

MR. ROTHLEDER: I guess from our perspective it looked like things went well, and they were able to balance to the tighter rules, although I do suspect that there were times where they basically stretched the threshold of those rules. There's folks in the audience that can be in a better position to answer that question about their actual experience, about how they tried to manage those, and the difficulties and whether there's anything that they need or any observations that they have about how those can be improved.

But from our perspective, it seems like actually things went fairly smoothly and maybe even more smoothly than we had heard expressed about the challenges of operating to tighter gas balancing rules.

MS. SCHAUB: That last part is what I was curious about. Did you experience any problems with resources because of the gas balancing rules?

MR. SUBAKTI: No, I'm not aware of it. As Mark mentioned, it's been pretty smooth from an operations perspective. The coordination has been very, very amazing. I'm pleased to have many more new friends from SoCalGas. I spent a lot of time with them understanding the gas system. I think it's been very smooth.

MS. MC KENNA: This is Anna. I think this is a good time to make this comment. Nancy Traywig, our director of operations, could not be here today, but we do talk to her a lot about her feelings, being so closely involved and everything. One of the things she did mention was that she was very pleased with how the generators had performed during this time and that she did feel that the smoothness of the coordination, the information flow, the ability to deal with things quite quickly contributed to the success over the summer.

So she said if I was coming, I would definitely mention that she appreciated the efforts on the generators' side in terms of dealing with these conditions during the summer. And that, of course, came hand in hand with the information flow that we had.

MS. CASTRO: Thank you for your comment.

I think we will proceed on to number 15.

MS. HOKE: On this one, we obviously have to be a little careful since after-the-fact cost recovery is one of the measures currently pending in a filing before us. But looking backwards, has anyone actually filed for after-the-fact cost recovery?

MS. MC KENNA: I will take that question because it's very easy. No.

MR. FARROKHPAY: Number 16 basically says have you used any other measures other than the ones that the Commission approved in the June 1 order to deal with the Aliso Canyon unavailability.

MS. MC KENNA: I will introduce the -- we did mention earlier that we did take some measures. We actually did address the material we had prepared for that question. Dede went through the experimental dispatches that we conducted over the summer. But we could certainly answer more questions or review the steps again that we took.

MR. SUBAKTI: Definitely, life is different for me, for a lot of the operators in California ISO. I made a lot of new friends in SoCalGas. The extensive coordination, it's really awesome. It's really good.

We kind of went through the June 19 event. That's the Blythe compressor challenge that we had. We used exceptional dispatch during that time. We talked about the July 21-22 curtailment watch. We also did use exceptional dispatch. But I think I also mentioned two -- coordinations about the two peak days, the two type of peak-day call that we have with the generators, and the other one with the reliability coordinators. Those are very useful during heat waves. I think we did have two heat waves. So those coordinations with the peak-days call. And I agree with Nancy's comment with the fact that during those heat waves, everybody, every generators were literally playing their role, coming out strong in day-ahead, and making sure that the gas supply and everything is available.

And last but not least, the August 16 day where we had lost all the three 500-kV line. Those represent a different challenge, because those are forced outages during the fires. We did have a lot of coordination with SoCalGas. They actually provided the gas that we needed to run all resources in Southern California that day, and as you saw in the chart where the gas consumption for that day after 3:00 p.m. was quite a bit larger than the day-ahead prediction, and the prices reflected accordingly. And I believe it was mentioned earlier that SoCalGas were coordinating really well and was able to pull the gas, including, I believe, from the other two natural gas storage.

So all in all, I do believe the preparation we did going into the summer allowed us to understand each others better and be able to coordinate each others better. The drill, the simulation of tabletop that we did in California Gas and California ISO and LADWP were very effective.

MS. CASTRO: Thank you.

And that concludes our morning agenda questions. We are ahead of schedule. So we do have some flexibility for time. At this time we would like to open the floor to questions and comments. Any interest in speakers, please begin to line up behind the microphone located in the center aisle. And I would like to ask, if SoCalGas is here and interested in speaking, all of us would be interested in hearing any remarks you may have. Each speaker will have about two minutes for their remarks. However, we do have some flexibility with time.

While we welcome your remarks, please do keep them relevant to the topics discussed today in the agenda. Please state your name and any affiliation, and then proceed to your question or comment.

Last, if you have a business card, please do leave a copy with our court reporter, who is here today located to my right, Sara.

Thank you.

MR. ZORNIZER: Good morning. My name is Devin Zornizer, director of real-time system operations at SoCalGas.

The only thing I was going to address was a clarification, I believe someone had a question in regards to the penalty waivers due to OFOs. So the five instances that we did have penalty waivers, they were based on the first scenario, which were Mark had alluded to this earlier where you have a low OFO called the day-ahead or even morning of. And as a reaction, we anticipated the fact that folks would want to schedule more gas on the system due to the low OFO. So a part of that settlement was we would -- if we -- if the overreaction to the low OFO caused a high OFO, we would waive.

In all five scenarios -- all five calls were based on that scenario. So there was no low-OFO penalty waiver due to the operational issues we had.

That was it.

MR. THEAKER: Good morning. I'm Brian Theaker, director of regulatory affairs for NRG Energy. NRG owns/operates -- Andy, you're going to have to help me -- about 3,000 megawatts of gas-fired generation in the affected area.

I would like to start with a question for the ISO first. For the July 21st event, can you disclose how many units were curtailed?

MR. SUBAKTI: I knew you were going to ask that, and I actually was looking for it, and I knew that was the number that I don't have in my notes.

MS. MC KENNA: I do, actually.

MR. SUBAKTI: You have it in your notes? Okay. Thank you.

MS. MC KENNA: I won't disclose the identity of the units. Obviously, that's confidential. But we did limit three units to minimum load, and that's the July 21st event. In that particular scenario, that's the scenario where we had been advised by SoCal that we had a curtailment watch the next day. And so we took the three units to a minimum load in an attempt to essentially minimize the gas burn so that we could reshift and position the units so that the next day we would not be subject to curtailments.

The reports given to me regarding the operations at that time was there was a significant concern that if we had to swiftly curtail the next day, which was a possibility, that that could cause a significant reliability issue on our system, and therefore, we took the actions in the day-ahead, the day prior to minimize and reduce those three units to their minimum load.

MR. THEAKER: Okay. Thank you. Let me first offer my congratulations to the ISO team and to all of us for surviving the summer. We were fortunate, but I want to acknowledge Cathleen, who led the stakeholder process prior to summer and did some great work in short time to get these provisions in effect.

So we do have concerns about -- we went through the process to get the measures that the Commission approved. We would greatly hope that those measures would be exercised in a transparent way rather than exceptional dispatch. We have a better understanding of the situation in July and appreciate that it was more of a localized event. And so I think we understand the ISO's thinking around that event. But I always would like for the ISO to lay out clearly its authority to take certain actions and lay out criteria for taking those actions in advance instead of, you know, resorting to exceptional dispatch in real-time. So we appreciate that.

Certainly one thing we learned from Aliso Canyon, I think the ISO acknowledges some limitations in its market bidding systems, and I think we will probably have an opportunity to talk about those more this afternoon.

But in general, we agree with the ISO that it was a good summer. We got through with a minimum of disruptions, and hopefully, the luck will hold for winter.

Thank you.

MS. CASTRO: Thank you, Brian.

MR. ROBB: I'm Jim Robb, I'm the chief executive of WECC, the Western Electric Coordinating Council. We're the regional entity responsible for reliability assurance in the Western Interconnection.

I want to make a couple of quick observations. First of all, I think I would congratulate the team in Southern California, both DWP, the ISO, and SoCalGas, for as Mark mentioned in his comments a really unprecedented level of coordination. And I think the situational awareness, the visibility that was brought to bear to work through a series of difficult issues when they emerged was unprecedented, and we would like to see that obviously continue, but we try to congratulate them because those three are strange bedfellows in a number of ways.

The other point I would make, and I want to underscore something Mark said, we did have an exceptionally good summer for dealing with this issue in that we didn't really have the simultaneous heat wave across the West, which frequently happens, and I think even despite of that, there were a number of cases where we had some fairly heroic actions on behalf of the ISO and DWP to preserve serving load.

So my request of the Commission and the Staff is to continue to give the ISO and DWP, to the extent that they come under your jurisdiction, the flexibility and the authority to use the range of tools that they will need to continue to manage through this situation until the gas situation is more fully restored.

And even though some of those tools may not have been used in the course of the summer, that doesn't mean that they won't be valuable in the future. So we would like you to continue, to the extent that you can, to give them that flexibility.

Thank you all very much.

MS. CASTRO: Thank you, Jim.

MS. BENTLEY: Hi. I am Carrie Bentley with the Western Power Trading Forum. I've lost my voice a little bit. So these comments will be very brief.

I wanted to echo Brian Theaker's comments with NRG. We at WPTF are also concerned not only when these mechanisms are going to be used but how transparent they will be. The use of EDs in these particular situations were perfectly understandable. We just hope going forward that the operators will be given more tools to actually feel that they have the authority to use, you know, what FERC has already approved.

We would also like the Commission and Staff to take a look at when you use things in real-time and when they're after-the-fact measures, Keith Collins mentioned, for example, deeming paths uncompetitive, that the Department of Market Monitoring would look at that and then deem a path after the fact that it was uncompetitive. It was our understanding that paths would be deemed competitive more in a real-time situation. So it still remains really unclear how paths are going to be uncompetitive going forward, whether this is going to be a one-off determination, or whether it's going to be automated. And none of this at this point in the BPMs is very transparent. We would like to say we hope going forward this is resolved.

Thank you.

MS. CASTRO: Thank you, Carey.

MR. SCHER: Hi. I'm Andrew Scher, also with NRG, with Brian Theaker. One point, or I guess one quick clarification that I wanted to make sure that I kind of emphasized. I think in some of the key slides, when he highlighted natural gas pricing even during OFO events, you know, relatively stable as he pointed out, it's important to remember, when an OFO is called and the market is, obviously, pricing to that event, gas is normally priced during an OFO at its opportunity cost. And so for an entity who's pricing gas pulling out of storage in the summer, the opportunity costs will be the winter.

So given the relatively flat nature of the gas curve, the winter, January, isn't necessarily maybe 30, 40 cents above where we are in the path. It's not going to represent, you know, an exorbitant price that you may otherwise see in the winter.

In the winter months, during the East Coast, you're used to seeing high gas prices, and that OFO event and when the gas markets move, obviously, in the Northeast, the prompt month natural gas price is very expensive. And that's what you typically see those markets go to.

Given that you don't typically see low OFOs called in any market during the summer -- and obviously Aliso is a bit of a one-off for the market -- the opportunity cost to pull gas out of storage would be January, and the relatively flat nature of the gas curve is, in my estimation, the main reason why you don't see those huge spikes that you might otherwise.

Thank you.

MS. CASTRO: Thank you for your comments.

Are there any last-minute speakers or questions or comments?

With that, this concludes our morning session, and we will begin the afternoon session at 1:30 p.m.

Thank you for all of your comments and questions for this morning.

(Whereupon, at 12:29 p.m., the staff technical conference was recessed, to be reconvened at 1:30 p.m. this same day.)

AFTERNOON SESSION (1:35 p.m.)

MS. CASTRO: Good afternoon, everyone. We are going to begin the afternoon session. To kick off this afternoon's session, we're going to be discussing -- the focus will be to discuss the longer-term solutions that may be necessary going forward to address any ongoing limitations at the Aliso Canyon facility.

I am going to ask if Mr. Mark Rothleder would please kick off the discussion to give some overview as to the winter assessment.

MR. ROTHLEDER: So in the longer term, there's kind of two time frames. One is what are we doing for this winter, and we talked a little bit about that this morning, and we will continue to talk about that this afternoon. Certainly, the winter assessment informed our action plan. Again, the winter assessment did indicate that there is the one-in-10 design criteria for the gas system is not able to be met without the Aliso gas facility.

However, as we talked about earlier, the -- that does indicate that there may be gas curtailments to noncore customers. Electric generation is effectively the first to get curtailed in the noncore customer set. And what it also indicated is that we have -- because the loads are lower in the electric system, we have greater ability to absorb and respond to those gas curtailments by shifting supply out elsewhere from the Southern Cal Gas System. But we would need to do that in advance in some cases going into a cold day, and that's why we believe some of the measures that, although we didn't use for the summer, some of the measures including the gas nomogram would be something that we would need to have for the winter to be maintained, along with some of the other things like the OFOs.

That's the first time frame, is what do we do for this winter because as I think your questions will identify, the field is not back. The field is not back to normal. It's certainly still limited. They have not started to do reinjections. I know the first question will get into that more from Southern California Gas, I think, will respond to that.

Looking out further, depending on the status of the field, we will have to start getting prepared for next summer, and we've already started that process. Our transmission planning group is starting to look at plans, what types of potential upgrades, transmission upgrades may be able to reduce the minimum generation for next summer and maybe reducing the reliance on the gas system. Some of those upgrades are already things that are already moving along. There's some transmission upgrades that are already planned to be in place, and some of those, in fact, are going to be coming on for this winter. Maybe Dede can expand on that.

And then we have to look out a little further. Maybe Kevin Barker can talk about this in this session. And that is, what's the longer-term perspective of -- in terms of things that we can do to reduce the reliance on Aliso in the longer term. And those may take on infrastructure changes. I know there's already things in place to bring additional electric storage, battery storage into the area. But we have to look at this holistically, because this is a large field. This is a large part of the infrastructure. You're not going to be able to change immediately. But if you look out longer term in the planning horizon, it opens up options to potentially do things that would reduce certainly the reliance. And that's something that the CPUC is looking at in consultation with the California Energy Commission and others, including the ISO.

So I think those are the time frames of what we're looking at, and all that will always be informed on kind of new assessments and always consider the new opportunities for the horizon that we're looking at.

MS. CASTRO: Thank you for that overview, Mark.

At this point in time, I would like to introduce Kevin Barker from the California Energy Commission to also provide an overview on the winter assessment. Thank you.

MR. BARKER: Thank you. So a few things I wanted to highlight about the winter assessment. We received a number of comments, actually back during the summer assessment, asking for a third-party review. And so we took those comments to heart, and we contracted with Los Alamos to have an independent third-party review of the hydraulic modeling of the gas system and our methodology of it. So that is one difference.

Another difference for the winter assessment was we did a gas balance look for longer duration gas balance, and we came up with four different scenarios. A number of those scenarios, we know we're long past that, so one of the scenarios being that we see reinjection on September 1st. Well, we've already -- we're past that deadline. And that was assuming that we might have up to 50 billion cubic feet in Aliso Canyon.

We also did two other sensitivities where we would see reinjection on October 1st. The difference between the two was one of them was looking at limited reinjection. The other one was looking at a reasonable estimate of what we could see in reinjection.

I think what we will get to in one of the later questions of -- do we think either of those are reasonable with the time frame of reinjection for Aliso, and I think the answer is no.

And so the fourth scenario was no Aliso Canyon. So I think where we're at is somewhere between no Aliso or limited reinjection of Aliso.

A thing I would like to note is we did hold a workshop down at Diamond Bar on August 26th. We received comments on the report on September 9th, and right now, we're reviewing those comments, and we plan to do an update of the -- we plan to do an update of the report, as well as a summary of comments and get that back out within the next few weeks.

In there, I wanted to touch on some of the other mitigation measures. Mark touched on one of them earlier today. But we have a total of 10 additional winter mitigation measures. They fit within six different categories. The first category is gas-targeted programs. One that we're looking at is is there the ability for a gas demand response. I know we haven't really been able to see that come to fruition thus far, but the mitigation measure asks for the PUC to direct SoCalGas to implement a DR program that reduces large customers -- that rewards large customers for reducing their load.

Another thing that we're looking at is what kind of marketing campaigns can we put in place for the public, so for asking everyone to change their behavior just in general going forward, and then, more specifically, on those kind of flex alert days, flex alert for gas, core use is going to be a lot different than what we're used to in the summer.

We also have what we're calling winter operational changes. So we're trying to continue with the tight noncore balancing rules. And so the Public Utilities Commission is looking at the rule that they have in place and any tweaks that they need to do to it.

We're also exploring the option for adding core balancing rules. So this is something that we've done before. But we suggest SoCalGas should utilize meter reads info is analyzed at the first part of the day and update gas quantities scheduled thereafter. And the PUC needs to actually take action on that.

And then the third one I won't touch on because Mark touched on it earlier today, but another mitigation measure that we have is, obviously, the use of Aliso Canyon right now. And as it stands, it's a little bit under 15 billion cubic feet, but that, obviously, is a mitigation measure that we have the rules already in place with the PUC, and they're looking to take a look at the protocols and see if they need to do any tweaks.

Another one is just -- we're calling it reduced gas maintenance downtime. This is one where we're just asking for there to be additional reporting on any type of maintenance on the system, whether it's planned or unplanned.

And then I would also note that we are looking at the possibility of increased gas supplies. So one of the issues that -- the comments that we received was that we're only expecting 60 million cubic feet per day from California natural gas production, and folks think that there might be other opportunities in the San Joaquin Valley. And so the Energy Commission is on point for exploring those options. We don't know really the economics or the operations of the line, and its line 85 that would bring it in, but that is another mitigation measure we're exploring.

We also heard about opportunities for liquefied natural gas. And so we're looking at what are the capabilities of using Costa Azul in Mexico with the Otay Mesa as the receipt point. There have been concerns expressed about affiliate rules issues. And so the Energy Commission and the Public Utilities Commission are looking at ways of mitigating that issue.

And then moving on to monitoring gas prices, economic consequences of gas curtailment for noncore, nonelectricity generators, these are the refineries, could have significant impacts on the gasoline prices in Southern

California. And so we're looking at ways of helping with that. Also, we have a mitigation measure for the Attorney General to monitor the gas prices and look for any potential manipulation and prepare actions, if needed.

Let's see. So those are our mitigation measures. One thing -- the last thing I do want to highlight that Mark pointed out was we did put into our integrated energy policy report, which is our large biannual report that looks at cross cutting energy issues in the State of California and comes up with recommendations. In last year's report we did in our scoping plan acknowledge the fact that in future years we were going to look at not only the long-term issues surrounding Aliso Canyon, but natural gas infrastructure in general. And the legislature weighed in on that. The bill that they put additional language was our budget act bill, Senate bill 826, and they called for the California Council on Science and Technology to develop a -- to have $2.5 million to develop an independent study exploring the long-term viability of natural gas storage. And so it calls for the PUC to oversee the work from CCST, with the help of the Energy Commission and DOGGR, the Division of Oil, Gas, and Geothermal Resources. So it was going to be housed at the Energy Commission, but now it will be done through the Public Utilities Commission, and that report is due to the legislature on December 31st, 2017.

Thank you.

MS. CASTRO: Thank you, Kevin.

I'm going to check in with Staff. Are there any follow-up questions? Dave and Chris and Pat, in that order.

MR. REICH: This is hopefully a simple follow-up question for you, Kevin. If an emergency situation came up now, there are rules in place that SoCalGas could pull from Aliso Canyon?

MR. BARKER: Correct. Yes. So they currently can. We haven't needed to use it yet, but they can.

MR. ROTHLEDER: Just to highlight, those protocols do provide for the ability for the ISO or LADWP to declare that they have an electric emergency effectively, and that would be one of the triggers that they would consider for withdrawing from Aliso Canyon. And that's part of that heightened level of coordination, is those protocols about how we actually call for and use the field when we need it to prevent wider electric interruption.

MR. ELLSWORTH: I just wanted to explore a little bit more on the additional supplies. You said there may be options for getting additional production. Is that anticipated to be in time for the winter?

And then also, on the LNG, how far in advance are those plans? Is anybody actually stepping up to buy cargo? And also, would Otay Mesa be large enough to handle the amounts of gas coming out of there to be able to add much relief to Aliso Canyon?

MR. BARKER: So the first part of the question, we've just started exploring the opportunities of looking at using line 85 to both put additional -- to be able to produce additional supplies and then actually can you actually operate the line effectively. So we don't have a timeline of knowing whether it's actually going to be available for the winter, but it's a measure that we're going down, and hopefully, that will have an answer at some point.

As far as the ability to receive liquefied natural gas, I don't think we necessarily have an answer. I think SoCalGas might have more information on, you know, what they've been exploring.

MS. SCHAUB: This goes back a little bit to this morning, but there was a bit of discussion about why we didn't wind up with power outages this summer. And just so we understand how the planning is done, when the planning was done for the summer or the planning now being done for the winter, does that take these contingency plans into account?

MR. ROTHLEDER: So when we did the assessment, we didn't know how effective the measures would be. And so the assessment was performed basically to assume worst case, we didn't have any ability to withdraw from Aliso Canyon. And that was not a bad assumption, because at the time we didn't know how many wells were going to be tested and available ongoing into the summer.

I think we have a little better picture about the well availability for withdrawal for the winter, but even that is somewhat dependent on the status of the field and the pressures available in the field to withdraw.

But to answer the question about the mitigation measures, the assessments -- the assessment was intended to inform the action plan, and it provided an idea of what needs to be done, what could be done. We did not circle back around and say okay, how effective those would be and determine what the reduced risk would be under those mitigation measures.

When we did the summer assessment, we assumed those mitigation measures would be helpful in reducing the risk, but as we said, we didn't believe that it would eliminate the risk, and.

We still believe that's the case. Even into the winter, these measures are helpful, and obviously for the electrical system, the lower loads are helpful. But I don't know to give the impression that there's no risk. The risk is still there. It's just that it's a different type of risk, and it looks like it's a more manageable risk, at least on the electrical system, but the gas risk is still there and may actually even be heightened because of the increased gas demand in the winter.

MR. FARROKHPAY: Mark, you mentioned protocols for declaring electric emergency to be able to -- for ISO or for LADWP to be able to withdraw from Aliso Canyon. Are those developed or underdeveloped?

MR. ROTHLEDER: Those protocols were developed for the summer. They will be revisited and refined as necessary for the winter. Really, effectively, before we get to the point where we're having to interrupt load, there's a step in there that basically allows us to call for and ask for withdrawal to prevent the need to interrupt load. It's a little more detailed than that, because there is lead time to withdraw from the field. So if we are going into a day that looks at risk, we would say that we would have that conversation with Southern Cal Gas, and they would actually, our understanding, place people there, prepare the field for timely withdrawal if we needed to withdraw on the actual day. So there is a bit of coordination day-ahead going into a risk period and then the actual withdrawal call-out if we are in emergency conditions.

MR. FARROKHPAY: Are these in the form of CAISO operating procedures?

MR. ROTHLEDER: No. These were protocols developed in conjunction with the CPUC and Southern Cal Gas, and they are documented. Do we have a companion procedure that refers to those? Yes.

MS. CASTRO: I would call on Dave.

MR. REICH: To follow up on that, so then the electric generation would then have preference over the core customers for that gas?

MR. ROTHLEDER: So the rules for withdrawal right now say that it's there to provide a mitigation against both electric and gas reliability. So it's both for the effectively maintaining core but also -- core gas customers, but also if the electric system is in jeopardy of having to interrupt load, that's a cause for needing to withdraw from the gas field.

MS. CASTRO: Okay. Thank you.

We are going to proceed into this afternoon's agenda. I would like to call SoCalGas to, please, come up to the microphone in the center aisle for agenda item 1 for this afternoon. Thank you.

MR. ELLSWORTH: Good afternoon. The first question is about the current status of Aliso Canyon, where it is in terms of being brought up again, how many wells have passed inspection, the latest projections for when it may come back online.

I also have a question, are there other hurdles to bring it back online besides just the physical issues with the wells?

MR. ZORNIZER: So as the system operator, I can't speak to specific issues related to bringing the field back online. So what I can give you is the status of where the wells are, different sets of wells. And I can also relate it to your other question in terms of timing. We're not necessarily focused on a time, date per se. We just want to make sure we complete the testing and safe return of the field. So there's no specific date established at this time.

To date, there's a total of 114 wells at the storage field. 100 percent of them or all of them have completed the first phase. So there's three phases of the testing. All of them have completed the first phase. 96 of those have moved on to the second phase of testing. So it's approximately 84 percent. 23 of those 114 have completed all the required tests. And 20 of those 23 have received final DOGGR approval. That's not to say we could have final approval to inject or operate, but they have received final DOGGR approval. And we update the DOGGR Web site weekly. So I imagine today Pacific time in the afternoon there will be a new update. So these might be about a week old, these numbers.

MR. ELLSWORTH: Just a quick follow-on question. When it comes back on, will the release capacity -- the ones that pass, will they be allowed to operate at full capacity, or it will be a reduced capacity, and will that affect the overall capacity of the field?

MR. ZORNIZER: What I can say is, based on the physical limitations of the wells that will be operating, the field will operate at a reduced capacity.

MR. ELLSWORTH: Okay. Thank you.

MR. REICH: One quick follow-up. Out of the 20 wells that have passed final inspection, per well, what is their withdrawal capability? Is there a general amount?

MR. ZORNIZER: I really can't say specifically. Based on what I know of the storage field, every well operates differently based on its depth and where it's in the zone. So I really can't say specifically, but the company is doing the testing.

MR. REICH: Thank you.

MS. CASTRO: Okay. We will proceed on to agenda item 2 this afternoon.

Dave?

MR. REICH: A little different take on the way the question is phrased. Sorry. A little different take on the way this question was phrased. Looking at your winter assessment and what you talked about earlier this morning, the notion that you have a minimum gas burn you have to maintain for min gen, what is that gas burn level, and then the corresponding amount of minimum generation? I probably have about four follow-ups behind that part, not to make it a multi-part question.

MR. ROTHLEDER: So the minimum generation in terms of -- I will put it in gas burn perspective. It looks like about 100 MMcf would be the minimum gas burn. And it's actually between about 20 and 96 and a million cubic feet, depending whether you have a contingency already occurring or if it's normal conditions.

So when we got to curtailment level that basically said you couldn't even burn that much amount, then we would be at a point where we would have to say okay, where do we get that gas, and that would be a condition of being in a choice of do we reduce load or do we withdraw from Aliso Canyon, and therefore, the Aliso Canyon withdrawal amount at least for electric reliability looks like it may be needed in about 100 million cubic feet per day, if and when we get to that point where we are encroaching on the minimum generation.

MR. REICH: Can you put that into an electric value as far as how much generation you think you have to carry?

MR. ROTHLEDER: Dede has the --

MR. REICH: While I'm at that, if there's a corresponding amount of generation that you have to carry, how much transfer capability does that support coming in?

MR. SUBAKTI: Sure. The Southern California load is significantly lower during the winter, roughly about 18,000 megawatts of load. Normal import into Southern California during normal winter day, it's about 12,000 megawatt. And if we were to actually calculate the import capability into Southern California, it's right around 17,000.

So first of all, normally, we don't import that much. We only import 12,000 out of the 17,000 import capability that goes into the winter. That 17,000 is actually quite a bit of an improvement compared to last winter, and part of it Mark did mention, we made a lot of, you know, physical changes in the system during summer, and we are expecting a new 500-kV line in Southern California Edison area that comes from Vinson to Mira Loma, and Mira Loma is where basically the L.A. Basin is. So that allows us to enhance that transfer capability to 17,000 megawatt-ish.

So when you look at that, you really need very little what I call minimum online commitment in the -- in the L.A. Basin -- in Southern California. We still have the hydro unit, the non -- pretty much the nonnatural gas unit available. So really it's minimum. If all the 500-hundred-kV line, if all the transmission line becomes unavailable.

If we do have a contingency, say, at one of the 500-kV line out of service, we could get pretty quick to need about 2,000 megawatts additional generation. So that's what -- the 96 MMcf day that we use is really assuming the worst. And you asked the question, if we actually lose that 500-kV line in the beginning of gas day at 7:00 in the morning and I have to go through it and I cannot put that line back into service, that is the 96 to 100 MMcf per day. It's about 2,000 megawatt.

MR. REICH: Let me ask that question again because I forgot to turn on my microphone for the second time. So we can repeat it for the court reporter. Of the 12,000 megawatts of load and 17,000 megawatts of transfer capability, is that all CAISO, or does it also include LADWP?

MR. SUBAKTI: So the total load of Southern California --

MR. COLLINS: That I mentioned is 18,000 megawatt, and that 18,000 megawatt include the LADWP.

MR. REICH: Just to follow up one more time on a part of it, is there any dual fuel capability in that region that could be called upon? Is there any efforts to start to bring that -- make that available?

MR. SUBAKTI: Sure. In California ISO, when we were looking for the mitigation for summer, we did survey and go to all of our resources, and to my knowledge, we no longer have a dual fuel capability in Southern California, in the California ISO territory. We are working closely with LADWP, and I'm personally aware that there is effort to try to have dual fuel capability in the LADWP area.

MS. CASTRO: I would like to make note that Pat has a follow-up question and Kevin Barker.

MS. SCHAUB: Do you have anything else coming online, either transmission or generation, that will improve your ability to operate during the winter, and will that affect your gas needs?

MR. SUBAKTI: Sure. I had mentioned very quickly, there is a transmission -- a 500-kV transmission line that we're already approved in a part of our transmission planning process, and that is the line that comes from Vinson to Mira Loma, 500-kV line, and that line is currently scheduled to be in service October. So next month. Looking forward for it.

That does give us another feed into the Mira

Loma-L.A. Basin-Orange County area. It's quite a bit -- 500-kV line is providing a lot of import capability, and that's, you know, why the 17,000 megawatt is, like I mentioned, is quite a bit higher than what normally needs to be, and it's different every winter, but this winter, it's pretty high.

MR. ROTHLEDER: So the winter assessment did include that upgrade, when we did the winter assessment that came out with the minimum gas burn.

MS. CASTRO: Kevin, would you like to follow up?

MR. BARKER: I wanted to do a follow-up on Dave's question of dual fuel capability. That was actually one of the LADWP's mitigation measures in the summer, that they did comply with South Coast Energy Management District to only have under extreme conditions when the power grid will actually go down, are they able to do -- have the capability of using dual fuel. That was actually granted. The permit for that, though, expired on September 13th, and so that is continuing as now a winter mitigation measure, and I believe they have an application before South Coast to continue with that.

MS. CASTRO: Okay. Thank you.

We will now proceed to agenda item number 3 with Pat.

MS. SCHAUB: We've covered some of this already, so I may put a little wrinkle in it, if that's okay. The question is how will the winter's increased demand for natural gas from residential, commercial, and industrial customers affect the amount of gas supply that is expected to be available to electric generators. You're welcome to expand on that, if you want, but has anything happened in terms of a curtailment plan that would change so that if there isn't enough supply, when electric generators get hit, is there anything? Does that add a bell or whistle to it?

MR. ROTHLEDER: So just to answer the question directly is that the core and the nongeneration gas demand does increase in the winter. As I indicated earlier, in the winter, it's about -- the core gas demand makes up about 60 percent of the total gas demand. Whereas, in the winter, it's about 20 percent of the gas demand.

I think the priority is, obviously, to maintain service to the core gas customers, and I think, obviously, if you reduce to the point where you interrupt those customers trying to get all those pilot lights relit is a major effort. So their priority is to maintain gas service to the core.

There has been some modifications. I'm not in tune with the details of the model, but there have been changes to the curtailment priorities. Effectively, if there is gas curtailment, electric generation may be curtailed, I believe, for 60 percent of the electric generation, and then after they get to the first 60 percent, they will move on to other noncore customers, to the extent possible, including hospitals, refineries, and stuff like that. And then if that's not sufficient, then effectively, it comes back to electric generation for the balance of the 40 percent.

And so whereas before -- and there is some judgment around that protocol, but that's effectively the steps that are taken. And that's all done before they ever get to the point of core gas curtailments.

So I think the bottom line is, if we get to that, we could probably withstand the first 60 percent. If we got to the second step where we're taking the last 40 percent of the electric generation, somewhere in there is where we would start to say okay, you're getting -- you're curtailing us so much that we would have to potentially interrupt electric load, please can you then withdraw from Aliso Canyon to prevent that from happening. So it would be in that second step of the electric generation curtailment.

MS. CASTRO: We will now move on to agenda item number 4 with Alan.

MR. PHUNG: Could CAISO provide more details or describe the operational plan that's currently in place for the upcoming winter period?

MR. SUBAKTI: Sure. As a part of our normal seasonal process, we do winter seasonal assessment to assess acceptable system performance for all lines of service, for following a single contingency, for following multiple, what we call credible multiple contingencies. These are all the contingency analysis that we do with different situations, what if the generation is not available, what if a transmission line is not available, what if fire and all this kind of stuff.

In addition to normal system assessment, our staff conducts the sensitivity assessment to look at specifically what are the impact in Southern California for potential gas curtailment. The result of that assessment is actually the one that was incorporated in the joint agency report. That's where the number comes up with the 22 Mcf a day, all the way to the 100 MMcf a day, talking about the 17,000-megawatt -- roughly 17,000-megawatt import capability into the Southern California bubble. That's all the analysis and the power flow analysis that we did for this particular winter.

Now, normally -- and we did look at this in the original assessment. We will continue to manage and coordinate our outages, electric generation outages, transmission maintenance, along with the pipeline and the gas facility outages. Some of you may be aware that we do have a regular call with my staff and Devin's staff on the coordinations of our generation outages, our transmission outage, and along with our -- the SoCalGas pipeline facility. We try to align all those to make sure that we are being efficient and reliability in our operation.

So that will continue. That will continue.

Now, one of the thing that we have been talking about is we are looking at coordinating this in the day-ahead manner in the following sense and we already know that in the seasonal assessment, we already see the fact that if we have a high electric load, electric winter peaking that could be at the same time as the gas usage hitting winter peaking as well, in these situations we may use the maximum burn nomogram that we were talking and we were requesting to be continued. And the thought was or the strategy would be utilizing the max burn gas nomogram in the day-ahead would reduce the exposure, would limit the exposure for us in the real-time curtailments. In other words, if you put 100 an Mcf a day as a target in the day-ahead, then the exposure that you have is 100 Mcf. So that is one way, one strategy that we could limit our exposure for the real-time curtailment.

The strategy going into the real-time, we would continue to coordinate with SoCalGas, utilize the nomogram, and exceptional dispatch in ensuring transmission reliability in the event of either a real-time event due to gas curtailment, but also it could be because of transmission forced outages.

So those are the plans going into summer -- going into winter. Sorry.

MS. CASTRO: Does Staff have any follow-up questions? Pat and then Dave.

MS. SCHAUB: As a part of that plan, are there any derates or outages of major transmission lines coming up that you have had to take into account?

MR. SUBAKTI: Sure. As a part of the assessment, we actually assess the -- when transmission maintenance is. Currently, the transmission maintenance, the normal planned maintenance that we're expecting to do, at least the planned outages that has been posted in our OASIS and LADWP OASIS, it's all been -- we've tried to coordinate to make sure that it doesn't happen in January where normally our load winter is peaking, January/February time frame. So we, to the best of our knowledge and to the best of our way of doing planned maintenance, we've tried to do all the planned maintenance right around October and November time frame for the potential winter peaking.

The other thing that we include in that seasonal assessment is the more -- the sensitivity of the more historical transfer flow from the Northwest because many of you know that many of the Northwest entities are winter peaking. So we did an assessment assuming the normal flow capability. For example, in our transmission line with Pacific -- the DC Intertie, the DC Intertie is our link straight from Northwest down to Southern California. It has a full capability or a full capacity of 3,100 megawatts. But during the winter, if there is high load in the Northwest, they normally don't export that much. Typically, it's always been about 12- to 1,500 megawatts, which is half of the normal utilization. That's actually what gets into the seasonal assessment as well.

MS. CASTRO: Dave?

MR. REICH: There was a reassessment of the emergency rating of Path 26. Can you describe that and how much extra capacity are you going to be able to get out of that? Are there limitations on how often you can go up to that level, as well as for how long?

MR. SUBAKTI: Sure; sure. First of all, I would like to share my appreciation with the coordination that has occurred between WECC Staff, peak reliability Staff, LADWP's, and really the neighboring TOPs in that area. As many of you, the Path 26 is a path that connects Northern California and Southern California. It consists of three

500-kV line, and it has what we call a WECC path rating of 4,000 megawatt.

Now, the WECC path megawatt of 4,000 megawatt is established some time ago, and it's basically to ensure that if we were to have a contingency of a loss of the two 500-kV line, the remaining one 500-kV line does not over load the emergency rating.

With that Path 26, there is an automated scheme that's called a Remediated Access Scheme, the RAS, where basically automatically this curtail generation in the north, curtail load in the south if the event were to occur.

Now, what we did is we basically get everybody together and review the validity of the 4,000 megawatt. Now, the 4,000 megawatt is a boundary condition that was set through a WECC path rating process. And that was set some time ago, and the system has changed. So we looked at the system and the true system capability and the true impact of the remedial action scheme that we have.

So what's happening, then, is that the true transfer capability of the system could actually vary between 4,000 megawatt, and it could go up to 4,100, 4,200, it could go 4,300. It really depends on how much load that we have in the Southern California that is available to be automatically curtailed if the two line were caught under contingency. So the true increase of the capability is somewhat linear in the availability of the load. So in other words, if you have high load, you have higher transfer capability. If you have lower load in Southern California, then you have lower transfer capability. But that actually works towards our advantage, because when you have the high load is when you need more transfer capability.

So that's basically what's going on with Path 26.

I do also want to note that although we don't put this too much, but the allowance of -- not the allowance -- yeah, the allowance or the provision to utilize emergency rating of a path with reliability and WECC is actually beyond just Path 26. Because we actually look at all the path that we have in and out of Southern California. For example, Path 45, Path 45 is our path that goes between California and New Mexico. We also look at that and ask this question do we have emergency capability in that path during that -- during the needed condition.

So what we have established is basically looking at every single path that goes into Southern California and looking at if there is any emergency capability into the system.

Now, there is also a process on how we could tap into that emergency rating. And one of the processes is actually following through the normal what we call the Energy Emergency Alert, the EEA process. EEA process is under NERC EOP standard, Emergency Operating Procedure standard, and it basically allows us to tap and work with the reliability coordinators and working with the neighboring TOP and neighboring BA, neighboring balancing authority, to utilize that emergency capability under some step in the Energy Emergency Alert process. So we wouldn't be able to use it under normal condition, but it would only be utilized when an EEA, Energy Emergency Alert, is called upon.

MR. REICH: Can you disclose how much extra capacity that would be if you go to use it?

MS. MC KENNA: I hate to do this, but we're not entirely certain that we can right now. So we're going to keep that confidential for the time being.

MR. REICH: Thank you.

MS. CASTRO: Thank you, Dede.

I would like to proceed on to agenda item number 5 with Tom. Thank you.

MR. DAUTEL: So I feel like I've heard a lot of these answers in the last question and Kevin's earlier remarks. But in case anybody wants to expand on this or fill out the record, what other contingencies could impact the winter's operations and what measures does CAISO plan to mitigate this?

MR. SUBAKTI: Sure. We have approximately 17,000 megawatt transfer capability. If you lose one 500-kV line, it could easily be reduced by 2,000 megawatt, just with that one most extreme 500-kV line. That's where roughly 100 Mcf a day that is in there. If we have generation outages, also, it may result in the reduction of transfer capability.

The gas line, I think one of the questions in there was the gas -- the upstream pipeline pressures and the upstream pipeline outages. That could also reduce the supply. I think the report talks about the fact that we assume that 85 percent utilization, which comes out to be about 4.2 Bcf. So if the supply of the gas is lower than that, then we could get into trouble as well.

I think you also asked the question about what measures that we are doing to mitigate some of that, mentioned about enforcing the gas constraint potentially in the day-ahead to reduce potential risks that we have in the real-time curtailment. We are looking at, I mentioned quickly following the EEA, the Energy Emergency Alert process, that would allow us two things really, to look at tapping the emergency path or transfer capability that is in there.

I do want to add that we also have a measure that reallocating our operating reserve, we have learned that reallocating operating reserve under zone would free up additional generating capacity. That has been useful. Of course, we have our water district that we could work to adjust pump schedules during the winter. And emergency system from a neighboring balancing authority, through that process, we have an agreement for an emergency assistance from our neighboring BA.

Those are our measure that try -- that would mitigate some of this contingency that could result in either a reduction of capability for us to import or as well as serve electric load.

MS. CASTRO: Thank you.

We will move on to --

MR. BARKER: If I could follow up with one more.

MS. CASTRO: Sorry, Mr. Barker.

MR. BARKER: One more mitigation measure, and it gets to coordination with other state government agencies. We do -- we have been conducting biweekly calls with the major participants, being us at the Energy Commission, the Public Utilities Commission, the ISO, but then also the California Office of Emergency Services and Cal Fire. And the biweekly calls do look at reliability throughout the state but also focused on Southern California and really looking at the risk of fires. We've seen fires intensify over the past decade or so, and so we do have a coordinated effort on high-load days, where fires are, and potential where transmission infrastructure, as well as electric generators and what we can do with regard to landscaping and things like that.

MS. CASTRO: Thank you.

We have move on to agenda item number 6 with Kate.

MS. HOKE: Obviously, a very important aspect of this conversation has been measures to maintain reliability, but one of the other objectives of the measures accepted in the June 1st order was improving resource's ability to recover their natural gas costs.

So is CAISO currently considering, other than measuring approved in the June 1st order or things that are pending before the Commission right now, is CAISO considering any other measures for enhancing gas cost recovery, either within the context of Aliso Canyon or just generally?

MS. COLBERT: This is Cathleen Colbert from the policy department within the ISO. So we are actually in the process of launching a new initiative as we speak and as we're talking. And we are in the final revision phase. So it will be launched as soon as possible. But that initiative will be -- is called commitment costs and default energy bid enhancements and its purpose will be to evaluate whether enhancements could be made to our market design to increase the ability for generators to recover their cost expectations.

We will be evaluating the market designs impacting bidding flexibility, where bidding flexibility is defined by the ISO under this project as the balance to allow generators or suppliers to submit bids that reflect their willingness to provide energy at a given price measured against the ISO's need to protect consumers against the exercise of market power or gaming strategies. That balance will be a very integral part of that stakeholder process, trying to determine what is the right balance to strike in order to achieve both goals that are very important.

The second part is that we will be looking at ensuring that the mitigated prices that we use when mitigated are reasonable reflections of supplier's expectations of costs.

Additionally, I want to note that while it is not going to be a part of a new initiative, we have previously stakeholders and have a board approval policy that will also increase the flexibility of generators to reflect their costs within the market processes and improve their ability to recover these costs. And that was stakeholdered under commitment cost enhancements Phase III.

The ISO, under this, will be transferring use-limited resources, pending approval because it hasn't been filed, but the policy is that it would transfer use-limited resources to a proxy cost option, which would enable us to develop their mitigated prices off of the improved, more timely daily gas price. Currently, it uses a monthly forward price that isn't really able to capture that intra-month volatility that we are seeing. Even we talked about intraday volatility that Keith spent time talking about. So being so far in advance, we are aligned that there are definite improvements and benefits to be made of pursuing that.

And those two initiatives have really been, it is one that is upcoming as well as our pending -- our intention to file those tariff revisions, are what we are intending to address long-term market enhancements.

MR. COLLINS: Market Monitoring plans to be involved in the upcoming stakeholder process, and we also believe it's important to have flexibility. But the measures of protection that are captured in our default energy bids have for us today and continue that going forward.

I think that there are some lessons learned and some observations that we've had that provide a pretty good foundation that we might need to think about going forward. One is the slide that I presented earlier showing the difference between the lagged index that's used and updated price. That, we've argued, can be a permanent rather than just a temporary feature to the market. We talked about Monday trading as well earlier today, and there may be some avenues in the day-ahead market. There is information available that could potentially be utilized to create updates that could be used to help frame that index better, particularly for Mondays.

Third, we talked about, in the slide that we had earlier today, we showed the same-day trading, and that information, much like the trading information that's available in the next-day market, is also available between that 8:00 to 9:00 period in the morning, and that information can be helpful or useful in helping shape real-time. And so we think that there's information there as well.

And then again more on a going-forward basis and not necessarily something to be mindful of the current items before the Commission is to think about the recovery mechanisms as well and how that may play a role in sort of a permanent solution going forward. Obviously, we want to work with the ISO on any other permanent measures as well.

But we wanted to lay out some lessons learned and some foundational items that could be useful.

MS. CASTRO: Thank you, Cathleen and Keith.

I would like to call on Bahaa and then Dennis for some follow-up questions.

MR. SEIREG: What exactly is inefficient about the way things are done now versus the way things can be done in the future? Is it just updating gas prices, or is it something more than that?

MS. COLBERT: Thank you for your question, Bahaa. I would like to note at this time we wouldn't be making a statement quite as definitively as you did saying they're inefficient. So we are launching a new initiative. The very first phase in launching a new initiative is to evaluate the issues, do analysis, really size out and provide support for an initial statement like that and at that time we would normally proceed into options and kind of moving forward.

Let's assume that we get to that conclusion, because the second part of your question is what about that that we would look at. So the ISO's reference levels, we have commitment costs ones that we call our commitment proxy cost calculations. We also have our dispatchable energy bids. There's on dispatchable energy three different options you can pick, LMP, a negotiated, and a variable. Let's just focus on the variable and the proxy cost, because it's a similar concept. We define the cost components that are reasonable within that calculation, and for the fuel cost components, we use the next-day price, and there's two different. For the day-ahead, we use the prior day, and for the real-time, we use the price published on our day-ahead morning.

There's -- the issue that we will be looking at and trying to size is whether or not the use of a next-day average. Average by definition may have some limitations that we may need to perform some analysis on, as well as it be next-day and not reflective of real-time prices is something that we will need to do some additional work on and turn back around to a conclusory statement. First we are going to be launching the first step, which is really determining if there are inefficiencies that would require enhancements.

MS. CASTRO: Dennis?

MR. REARDON: Just a quick question. I know there was some concern by EMI entities during the previous proceeding about whether they could recover their gas costs. Would this reformed proposal extend to -- would the scope extend to EAI entities as well?

MS. COLBERT: Dennis, thank you for that question. I think this may have just been a clarification issue is that there were some scope items that we put into Phase I of Aliso Canyon's filing that came from a prior stakeholder process called the bidding rules enhancement process. That has recently been filed. So we will be careful. But under that, those were all stakeholder, systemwide and so when they were traded in Aliso, we did caveat those would remain systemwide. So we have backward looking after-the-fact cost recovery under the temporary provisions. It does apply across the system. And we did clarify that with our stakeholders off-line afterwards.

MS. MC KENNA: This is Anna. I just wanted to clarify. I think your question was also targeted at upcoming changes, if we were to make any --

MR. REARDON: Right.

MS. MC KENNA: In that regard, anything that affects our real-time market would also affect the EMI entities. So we would be looking at that as well. And that is the opportunity for the EAI entities to participate in the process and provide input.

MS. HOKE: Just one more follow up on this. A recurring theme we have seen over and over again is the ability to recover OFO penalty costs. So has that been a part of any of CAISO's discussions? Also, I know as we discussed this morning, pursuant to the current settlement that's in place, there are some waiver options. And so this might be a better question for SoCalGas. Has that been something that's been considered as maybe extending some of those? So CAISO first, and then if SoCal has anything to say.

MS. MC KENNA: I will make a couple of comments with regard to the OFO penalty assessments and how they might translate into our market. We've had a lot of discussion about that at the ISO, and some of it has been public through our filings as well. You've all read that, of course. You've all had discussions as well at the national level about these types of issues.

There's controversies one way or another, of course, how we do it and how we conduct those. But I think that is going to be a part of our next round of discussions. Again, it will be a part of our stakeholder process to consider to what degree and under what conditions those might be recoverable. But in our -- I just wanted to note, and I can't get into it, actually, now that I think about, is it's pending before you, because we do have a proceeding before you. Anyway, yes, we have considered it. It's a part of our continued discussions with our stakeholders. And we hope to shed more light on that ourselves.

And I will turn it over to maybe if Cathleen has any other comments.

MS. COLBERT: Thank you, Anna. I wasn't sure, because there is a pending filing. But if we focus it on the Aliso filing perhaps? Okay. So focusing on that lens, we did have a lot of different discussions. Our position, the ISO's position is that as far as cost recovery for kind of anomalous events that we're not -- those risks were not able to be managed, that is something that an after-the-fact cost recovery is more appropriate for.

And given that these are one-off, very anomalous, couldn't be anticipated events, they're not something that we can streamline a detailed list of factors or triggers to evaluate. And it is something that there is many different sensitivities to, and it might even require some guidance on when it is appropriate or not appropriate for such an issue as an OFO. And that is one of the reasons that we put in the first phase as filing the after-the-fact cost recovery proposal to extend that right to file under a 205 here at the Commission for such an event, because we did think that it was more appropriate for a just and reasonable assessment to be made, given all those different facts and circumstances under that, especially given the sensitivity behind those noncompliance charges.

MS. HOKE: Thank you.

MS. CASTRO: We have a follow-up question from

Pat.

MS. SCHAUB: This follows up on Kate's question, but it's two-pronged. One is, when you're thinking about your cost recovery provisions, do you take into account other mechanisms such as SoCal's OFO forgiveness? And what would you need from something like SoCal's OFO forgiveness to feel like you can rely upon it so you wouldn't have to or would -- so you wouldn't have to use it, or would you always need to be able to have your own mechanism? I'm trying to figure out the interplay between the two mechanisms.

MS. COLBERT: Yes, Pat, this is Cathleen again. And I would like to kind of toggle maybe a little bit of the narrative around the cost recovery. Cost recovery wasn't designed to necessarily provide recovery for those charges, nor was it designed to be something that we would be able to say this is exactly what it's for. It's for an anomalous event that the market processes, the market design could not capture. And kind of focusing on our long term, our lens and our priority under our long-term initiatives is not cost recovery.

Our long-term priority is to improve the valuation of resources within our market processes, so that the market's dispatch solution supports -- is the least-cost constrained impact. So we're looking for efficiency improvements in our market processes. That's really the lens just of what I was referring to in the new initiative rather than kind of the after the fact.

The after the fact was stakeholdered and under bidding enhancements and it was a slightly different conversation than the one that we're proposing to address the issue teed up under this.

MS. CASTRO: Thank you.

We will move on to agenda item number 7 with Alan.

MR. PHUNG: With the growing dependency on natural gas, what long-term action is the ISO considering in regards to making the transmission system more robust or reliable?

MS. MC KENNA: This is Anna. I just wanted to make a suggestion with regards to this question. It's a little bit of a request for clarification as well. But we did view this question very similar, if you wish, to the question pertaining to what elements in our transmission planning are we considering with regard to Aliso. So there might be a little bit of overlap and combination between those two. We will probably get into that question, and that is question number, as I flip through this, 11.

MS. CASTRO: We can cover both of those questions.

MS. MC KENNA: Thank you. We think there's a lot of overlap between the two.

MS. CASTRO: We agree. Let's cover number 7 and number 11.

MS. MC KENNA: Thank you.

MR. ROTHLEDER: I think I will take this one. So as a part of the ISO's transmission planning process, we do have a component that is now specifically trying to address electric-gas coordination. And that has been in place, however, for the 2016-2017 transmission planning cycle, it's taken on a unique and kind of special focus around the Aliso Canyon situation. And indeed, next week, we will be coming out with kind of our first -- or a stakeholder process around our 2016-2017 plan. And in there, there will be discussion about kind of an assessment and a planning horizon around transmission upgrades that may be helpful in addressing the Aliso Canyon constraint.

So that is coming up on September 21st and 22nd. The ISO, this work relied, in part, on similar type of study that the joint agency task force work did for the summer. And so it's very similar, but it does take on a unique focus in the sense of what are the options and the planning horizon, including transmission upgrades that are already in progress or already approved and what other ones may be beneficial to reduce the gas reliance.

If I could, one more thing on that, I'm going to twist the question around a little bit, because there's also -- I want to articulate that there is a changing landscape of all gas storage facilities in California. There's some new rules that are coming in place by the Division of Oil and Gas and Geothermal Resources. And there's been recent bills, Senate bill 887, that highlight that there may be changes around the ability to potentially -- how the storage facilities are used, how the wells are used that may affect their production ability going forward.

There will probably be enhanced testing and review efforts, and those could impact availability of the storage fields at different times. And I think we're watching that very closely from the perspective of because of this changing landscape, are there measures that may need to be kind of more permanent measures that may need to be in place to be responsive and make sure that the electric system is able to coordinate with these changing conditions on the gas systems.

So while we're not -- we're kind of focused here today about the use of the measures and extending those measures into the winter. I want to give you some foresight that we may be looking at potentially making some of these permanent, to the extent they are useful and effective in mitigating some of the broader gas changes in California.

MS. MC KENNA: This is Anna. I wanted to follow up on Mark's theme with regard to that issue. As he said, we are watching these changes in the gas industry very closely, and they immediately affect us once they come into play.

Commissioner LaFleur, I think, mentioned earlier this morning this has given us a bit of an opportunity to think creatively. Necessity is the mother all of inventions. Some of the tools we've created through this process, although we haven't had a chance to use them, are tools that we think we might be able to use in other parts of our system.

And we do plan on looking at that very closely. If we were to make some changes, I want to assure you from a procedural perspective, the tools that we will be asking for extension in this process will be only for the purposes of Aliso. Given that short time frame, we don't have the ability to develop those throughout. We would have to conduct another stakeholder process and make sure those are more fully developed for purposes of system-wide usage.

But it's certainly true, as Mark is foreshadowing, that we are looking at these issues, and the lay of the land is changing quite a bit for the gas pipelines in California, and that may have implications for us.

MR. FARROKHPAY: Just to complete the rest of item number 11, the transmission planning studies have a local reliability assessment component to them, especially the studies that you refer to in this particular cycle, the 2016-2017 cycle, is that also going to address the local reliability requirements that then feed into the resource adequacy framework?

MR. ROTHLEDER: Yeah. They mainly have focused on the local reliability needs, kind of coming up with, again, local minimum generation need for local reliability purposes to meet peak loads in whatever planning year in the planning horizon. But when they do the studies they also do look at the underlying ability for import capabilities, Path 26 limitations, skit import limitations into the area. So they look at the broader set of constraints on top of the local reliability constraints when they're looking at those -- doing those planning assessments.

MR. FARROKHPAY: You said those are -- will be released next week?

MR. ROTHLEDER: The first set will be released for discussion next week, yes.

MR. FARROKHPAY: Thank you.

MS. MC KENNA: Not the LCR, not the locally constrained area reliability study --

MR. SUBAKTI: Local capacity reliability area.

MS. MC KENNA: I'm so used to the acronyms, I actually forget what they mean. Thank you. That will come out next week. It's this study we just did and are conducting for based on the summer experience and what we could anticipate that Mark was referring to.

MR. FARROKHPAY: I was just trying to get a sense of whether for next resource adequacy year, whether we will have something new that will be coming out of this special study, or are those all predetermined already, from the LCR studies that were done earlier in the year?

MR. SUBAKTI: Sure. My staff is also working closely with the PUC Staff with regard to resource adequacy's role in California.

So the thought behind this is that we are trying to find out what is the impact and what transmission infrastructure need that we need to actually implement in terms of physical wire or physical -- maybe synchronous condenser or something we need to do in there.

Once that's -- once those are implemented in the system or have a transmission plan being actually built in the system, then those physical facility will be included in what we call the LCR study, the local capacity requirement study.

The LCR study is pretty much basically done with looking at what is the next minus 1, line out or generation out, and that is normally done right around April time frame.

So the LCR study's requirement for the resource adequacy for 2017 is already completed, and we are currently not looking at redoing the LCR study for 2017, because it's -- it basically already includes all of the transmission facility that we know is going to be in service by 2017. But the expectation is, once we do all transmission planning analysis and make an investment choice with regards to infrastructure building, then it will be included in the following LCR studies.

And of course, with the new capability, the expectation is, then, the resource adequacy might be lower for -- the resource adequacy requirement for the local area might be lower based on that analysis after the facility's been identified.

MR. ROTHLEDER: And I think being in April, the local capacity requirement study associated with resource adequacy, that will certainly be informed of the status of the field and the long-term expectation of the field availability. So I think that will be the next opportunity to make any resource adequacy local capacity requirement adjustments going forward into the 2018 time period.

MS. CASTRO: Okay. Thank you.

We will proceed on to agenda item number 8 with Dennis.

MR. REARDON: This is another one where I think we've touched on this before, the specific changes that CAISO has made in coordinating with everyone regarding the limited availability of Aliso Canyon and the lessons learned from those.

If you could expand on those relative to a sort of looking forward perspective, that would be great, and also if you could let us know if there's any reason why these changes in coordination couldn't be permanent or if you were planning to make them permanent.

MR. ROTHLEDER: I think the -- as I said earlier, I think the level of coordination between Southern Cal Gas, LADWP, the ISO, the state agencies, market participants really is significant and unprecedented in terms of the changes being made.

And I think you're correct. I think we've learned a lot from those, and I think a lot of those will become permanent fixtures in terms of our going-forward coordination efforts and may very well expand to coordination with some of our other gas companies in California, including enhanced outage coordination, maybe more advanced information about the expected gas burns. All those, I think, are transferable and could be certainly permanent tied going forward.

I think there are lessons to be learned. As I said earlier, probably not everything went perfectly, and I think we're still learning as we go about how to make things better and enhance them. And as those learning opportunities come along, we certainly do implement those going forward. I think early on going into the summer there was some opportunities where we enhanced outage information, and we have that in place now with Southern Cal Gas. There's information that we get through our nondisclosure agreement that we have some advanced notice that we can incorporate into our planning process -- or our operational planning process so that we don't double up outages that could not align well with each other.

And I think as I said earlier, there's probably an opportunity for increasing further the transparency where we can about the measures that we're taking with all stakeholders. So we will look for those opportunities.

MR. REARDON: You said a few things didn't go perfectly. Would you like to elaborate on any that didn't go perfectly?

MR. ROTHLEDER: I think the one that I described early on, there were some outages, planned outages on some storage facilities that, going into the summer, we were already kind of nervous about what was going on, and we weren't aware, but we became aware of an outage on one of the storage facilities that could have affected us. And once we knew that, we had some broader discussion about what could be done. And we understood better why it was going on early in the summer instead of later in the summer, and it was really to kind of move it out from the higher risk later summer conditions.

So once we understood that, we understood the reasoning for that. But just not being aware of that and having it come up always makes us nervous. So that was a learning opportunity.

MR. REARDON: Thank you.

MS. CASTRO: Thank you.

With that, we will proceed on to agenda item number 9 with Dave.

MR. REICH: The Commission has accepted CAISO's compliance filing to leave its timelines in place for its day-ahead nomination, the time it runs its market. But I do believe that was before Aliso Canyon went out. And it was raised as an issue in the June 1 order, and I guess the Commission left it alone.

But I think in going forward, if there is no Aliso Canyon or it's severely curtailed, and perhaps in light of CAISO's ability to do better forecasting, is CAISO considering or at least looking at potential benefits to moving up its timelines to more closely match the gas markets?

MS. MC KENNA: This is Anna. I'll start the discussion on this and then I'll ask Cathleen to elaborate a little bit on the issues related to this item.

So we did actually look again to see whether we should change the timeline in our Phase I effort, and through our discussions with our participants, we realized -- and with the gas company, we realized there was really not going to be a benefit to it, and it would have increased the risks. And I'll ask Cathleen to describe that.

But having realized that, we didn't put it forward last time, and we weren't thinking about changing that again this time around because we still feel those constraints exist. That doesn't mean we'll never look at it again. Going forward, it might be a different issue on other parts of the system. But for the time being, we think that's not necessarily going to add a benefit to us.

I'll ask Cathleen to explain a little bit about the structural rigidity that exists in terms of changing and providing benefits.

MS. COLBERT: Thanks, Anna. This is -- and this was stakeholdered, I would say, and, as Anna mentioned, twice, it was done through bidding rules enhancements and then we did another review of it under Aliso Canyon Phase I.

And not surprisingly, stakeholders' positions did not change drastically between those two processes. But part of the issue is there's so much actual overhead infrastructure that is in place, both for the ISO as well as for the stakeholders. So as far as a cost, when you start to look at the costs and benefits of that kind a move, the costs are extremely high of moving the market timeline earlier. The change requires operation changes across every single participant, as well as the ISO.

Looking at the benefits, there are -- there might be improved benefits, but those benefits were not something that we could be certain might really -- because conceptually, I understand where the question is coming from, because you get the results earlier, you have more information.

And that is why we proposed the two-day-ahead to provide those schedules to market participants. We talked through this, and we asked the question, what provides the most benefit, providing you kind of an advance notice, some information that can give you an anticipation of what your burns would be or moving the day-ahead market timeline.

And having that conversation, the outcome is what you saw in Phase I filing, is that the advanced notice more information that they could use to better prepare for their day-ahead market had larger benefits. Some of the constraints that Anna's referring to is that -- the first one is that while we have had forecast improvements, our forecasting of variable energy resources or intermittent resources, it gets better the later it's done during the day.

So we have already struck a balance as when we run or do these forecasts, and that's something that stakeholders weren't very supportive of undermining through a move.

Additionally, there's some pretty deep-rooted processes around intertie transactions marketing that is done on the west, as well as just kind of procedural history as to how that is done and how it's tagged. And moving it earlier imposed potential issues on the intertie markets, on the import and export transactions, which is liquidity that -- and we've even talked about those imports and exports providing value through this process as a mitigation measure.

And so undermining their flexibility and their ability is another huge cost of making that move. So we had a very dynamic conversation about these moving pieces and came out that additional information, especially as we noted our two-day-ahead and our day-ahead results seem to be we did see some pretty favorable outcomes of them lining up fairly well. So this information was helpful, and we saw it over the summer provide them what they needed to bid more consistent with anticipated conditions in the day-ahead.

MR. COLLINS: Just to echo a point that Cathleen just made, is that the timing of the -- of both the gas markets, the bilateral electric markets, and then the ISO markets, if the ISO market were to move any earlier, it creates some challenges in terms of the timing of the different markets that are occurring.

One of the things we talked about is the extent that updated prices could be used, you sort of lose that, and you -- the ability even for the trades to actually have occurred in some cases versus when the ISO market is running is kind of overlapping potentially, depending on how early you run it. So I think Market Monitoring's position is that we don't -- we also don't see the benefits of shifting that as well, and the current timeline is -- it doesn't end up in these timing issues that you get with these other markets.

Thank you.

MS. CASTRO: Thank you all for your responses.

We will move on to agenda item number 10 with Kate. And also, I wanted to make note that we are probably going to elaborate a little bit further on the stakeholder process in this question as well.

MS. HOKE: So obviously, you've just started the Aliso Canyon Phase II stakeholder initiative. And we've talked a little bit about some of the extensions that you may want to do. So I just wanted to open it up to you guys to see if there's any of those things that you would like to highlight here.

And also, I think what I was understanding is that would be another set of interim measures to deal specifically with Aliso Canyon. I just wanted to clarify that. And then after that, I will probably have a follow-up question for Keith regarding exceptional dispatch.

MS. COLBERT: Thanks, Kate. And yes, I'm happy to clarify. So our stakeholder plan for gas/electric coordination is that we will be -- we launch Phase II, and it will be for a filing for temporary provisions to extend us through winter and, perhaps, past. I've mentioned some.

We have pending filings waiting on that opportunity cost filing under commitment cost enhancements, as well as we've launched this new initiative. So we are hoping to try to bridge as much as we can until we can get some long-term enhancements. But we're still working through exactly what the details of that means.

Both Anna and Mark have mentioned that we are evaluating the provisions. We will talk through whether or not -- we've left it on the table that they may be needed in a more permanent fashion. We are waiting to do that evaluation until we have completed the winter period so that we can do the same kind of postmortem and see how it functioned through winter. We will likely be launching another stakeholder review and ask that question, what needs to be made permanent or not, some time in Q3 of next year.

What we are -- want to talk about -- so your question here is largely about the Phase I provisions and what we plan to extend, retire, and any changes. So I'm going to walk through kind of each of them as quickly as I can.

The first one is providing the two-day-ahead market information. As we just talked about, we got positive feedback that they were helpful. We saw it in the bids through Mark's chart he showed in his slide deck of the improved ability to manage that real-time/day-ahead burn. So we are going to -- we plan to propose to extend providing that two-day-ahead information to the market participants.

Just noting changes very quickly is, in addition to providing the two-day-ahead residual unit commitment information, there has been some request for us to consider providing either more clarity or, perhaps, giving them the gas burn information that we're sending to the gas company so that they, again, coordinating the information that we're sending to everyone.

On the second scope item, using the improved day-ahead -- used the improved next-day index, the index is published the morning of our day-ahead run in our day-ahead market processes. We plan on implementing this as soon as possible once we receive some clarification, and we will continue to be asking for the authority to do this, because through both the ISO's analysis and DMM's analysis we have seen analytical support for the benefits it provides.

I just wanted to note, as Keith mentioned, that DMM also believes this is very important, and that's something that we're aligned on, and we are working together.

On the third scope item to provide -- where we asked for the authority to impose a scaler in the real-time markets on our gas price indices, two different ones, the commitment costs and then default energy bids, applied varied scalers. We are planning on asking for an extension of this. Again, this is really -- we have heard positive feedback from the stakeholders and that people have been using them in order to -- both using the rebidding flexibility that came through kind of the base bidding rules enhancements scope items and using the increased scalers in the real-time, which is showing -- providing them greater flexibility to reflect that higher real-time price information relative to the day-ahead markets.

On the fourth one, the rebidding, which I just touched on, so under that bidding rules enhancements, we had the rebidding of commitment costs. If you did not have -- for hours without a day-ahead schedule, we are now providing the functionality for suppliers to rebid their commitment costs in the real-time. Once committed, they wouldn't be able to rebid through their minimum run time. We're proposing to extend that as well.

We also proposed provisions to no longer insert bids for resources without a day-ahead schedule that do not have a real-time market must-offer obligation into our real-time process, and we're proposing to extend that. Those are two of the bidding rules scope items.

Looking at now the operational tools. We talked about the max and the minimum gas constraints. We are planning to ask to extend the authority to enforce the gas constraint, but we do plan to retire the minimum constraint. After the summer and given the flexibility to reflect lower bid costs if you need to manage that limitation, we don't see it as a need.

On the authority to adjust the internal transfer paths capability, what we talked about, we are planning to retire that one.

And Dede, I thank you very much for your thorough explanation of the change in the peak reliability policy around adjustments to the system operating limits that we can use under emergency conditions.

The issue that was stakeholdered on that item was really being able to try to avoid shedding load during really difficult times to manage the grid in Southern California. And so this change to the policy addresses that. And so that's why we're proposing to retire that scope item.

For the authority to extend virtual bidding, as we mentioned, we do have some concerns about potentially impacts of changes when you have the max gen constraint in the market versus when you don't. Let's say if you have it in the day-ahead and you don't have it in the real-time, that that does impact your dispatch solution, which can impact the marginal unit.

So there are potential differences. And depending on the frequency of the constraint, there is a question as to whether or not it might be systematic or not. So we are asking to extend the authority, just given the -- we have not gained any more certainty than we have from Phase I. And so we do believe that all of our requests under Phase I, it's the same condition that we would need this authority.

And the last one is that after-the-fact cost recovery. That's also bidding rules enhancements. We're asking to extend that in a temporary perspective if we do not receive an order from the filing that has been submitted. So we do intend to ask for those again if we haven't received any feedback.

MS. HOKE: Thank you.

MR. COLLINS: If I may just give the Market Monitoring perspective.

I think we are in favor and support the extension in the short run. We think it's very prudent that the measures that Cathleen talked about have been very helpful. There's a couple I just want to highlight here.

One Cathleen noted is we think the update to the day-ahead with the ICE information is, perhaps, the most important from our perspective. We do think the scalers should also be extended, but based on empirical evidence, I think the discussion early on was was it too low. I think we also want to also ask the question well, is it too high, and if there's anything we need to do, again based on permanent -- based on the market results and any potential results that are occurring.

And then in addition, we also believe -- and this is sort of an additional item that we identified. There wasn't, at least in the initial discussions on Aliso, exceptional dispatch wasn't discussed as much. And so as we went through the summer, our concern became well, if exceptional dispatch is a tool, that it has been used and could be used, then we believe that mitigation would be prudent for both incremental and decremental exceptional dispatches.

And then finally, we do think that the mitigation measures that have been put in place for the suspension of virtual bidding in case of some inefficiencies, and then also the appropriateness of deeming constraints uncompetitively, we think those are important.

Just one clarification on deeming paths uncompetitive. We would not be doing this retrospectively. It would only be prospective. It would be based on observed. We have to observe the gas constraint in place. We would have to identify that it appeared that it was causing a competitive constraint -- a transmission constraint to be deemed competitive when, in fact, it was uncompetitive. And then we'd also have to observe impacts on bids and prices as a result of that.

And so the analysis we would do would identify that, and then we'd provide recommendations to the ISO as to we believe this path needs to be deemed uncompetitive. But again, nothing would be retrospective, and we'd likely be able to provide a summary of what we saw, maybe not before it was deemed uncompetitive but, perhaps, you know, afterwards why it was chosen, what was the analysis that was done.

And so that's just to clarify a point from earlier. Thank you.

MS. HOKE: That actually does lead me to my follow-up question, which is in the current tariff, there are provisions that provide for mitigating exceptional dispatches that are associated with noncompetitive constraints. So I'm kind of wondering, since you already have the ability or this package would provide the authority to deem paths uncompetitive in the Aliso Canyon area, how does the current tariff not already include the mitigation authority that you would need?

MS. MC KENNA: I can help try to address that, actually. It's a little bit confusing because we use the same terms for multiple such things.

But in our tariff, we do have the authority to mitigate exceptional dispatches for noncompetitive constraints. But those are for particular exceptional dispatches.

What we're talking about here is in the market itself, when we enforce a constraint, the max gen constraint, currently, there isn't -- there isn't the ability to say that we would select some path as not competitive as a part of our market power mitigation, and that is what we are talking about here when we're talking about the procedure that DMM would use to identify those as noncompetitive. Then that would then go into our market systems and flows through.

Whereas, the procedure you're thinking up in the tariff is with regards to exceptional dispatch. So I think there's a bit of confusion there. I'm starting to get that, that there's a bit of confusion there, and I believe that's the answer to that.

MS. HOKE: I think I'm going to have to digest that a little bit, because I feel like we're still talking about exceptional dispatch.

MS. MC KENNA: Well, what you were talking about, I can confirm, what Keith was talking about, was the designation of competitive path assessments for local market power mitigation?

MR. COLLINS: I actually talked about both. I did mention exceptional dispatch, and I did talk about that.

To follow up, there are -- for exceptional dispatch, there are very limited reasons why I would mitigate, and you would have to have uncompetitive transmission path, which as I understand is different from uncompetitive gas constraint or --

MS. MC KENNA: That's a difference, too.

MR. COLLINS: And I think we're also recognizing that it's incremental, and I think one of the points that we're noting is that decremental should also be considered as well.

MS. COLBERT: Before we move on, I did want to note, because a part of this question asked about changes, and while we're still working on Phase II, so there may not be anything conclusive really today, we are going to have additional conversations. Some of the technical implementation details, we've talked through kind of the high-level policy of them, but we are reviewing some of the formulations, as well as the factors that were detailed in the white papers and some of the procedures on using the maximum gas constraint in the papers just to improve overall clarity and to ensure it serves the purposes of operations.

MS. MC KENNA: This is Anna again. I actually wanted to take this opportunity to just say that everything we've talked about here today about coming to you is all subject to our board approval, which hasn't happened yet. And even before that, it's subject to the process being quickly as Cathleen has just described. These are our impressions here before you, but we do have some work to be done.

And I wanted to address the issue exceptional dispatch, perhaps, as well. This is a very important issue to us, the mitigation of exceptional dispatch. DMM has raised a very good point, and we are looking into it very closely. We can't say right now it's going to be a part of the package we're going to bring to you. I will describe what we have ahead of us over the next 15 days.

But there's no guarantee that we'll get all the analysis done by then, but the ISO is committed, and we have committed and working very closely with DMM and our stakeholders to explore exactly what type of mitigation is needed, under what circumstances. And if we could not get that to you by the time we make our filing for Phase II, we would come back and make another filing and make sure we have that in place if it's necessary. So it's not a part of the package right now, because it's something we're considering very closely right now and have to conduct some additional analysis on.

MS. CASTRO: I believe we have some follow-up questions from Staff. We'll start with Dave and then Pat.

MR. REICH: From Staff's perspective, you're looking at probably a mid-October filing date.

MS. MC KENNA: Yes.

MR. REICH: So when would you request action by?

MS. MC KENNA: Okay, so thank you for leading to my -- so I was not very happy to ask for such quick action. But we have commenced our stakeholder process. Once the winter assessment came out, we did the best we could to get our ideas out to stakeholders. We're looking to next week to actually issue a -- what we would call a draft final proposal and then take to our board the draft final proposal on October 3rd and then come to you with a filing on or about October 15th. And we will do it as soon as possible after October 3rd. It's entirely possible that we could do it sooner than that, but we do have some stuff that needs to get done before we bring it to you.

Once we get to that point, that gives you 45 days, hopefully, to issue us an order by November 30th so we can continue these measures by December 1st. And I see I'm making people very happy here about that, but given the time frame, that's sort of our trajectory right now, to request for leave from the 60-day notice so we can have an order in 45 days to get the measures in place for December 1st. They do expire otherwise on November 30th.

MS. CASTRO: Pat and then Saeed.

MS. SCHAUB: I'm trying to get a sense of scope. Mark, when you were here at the Commission meeting some time back talking about the summer preparedness, it sounded like the biggest concern dealt with the 17 plants in the L.A. Basin.

Is that still what we're talking about here, or are we now talking about all of Southern California? Can you elaborate on kind of what the scope of this is?

MR. ROTHLEDER: So even back then, the most immediately affected resources are in the L.A. Basin. I think what we learned from the analysis and the assessment is that if the gas system is stressed, those stress conditions can manifest themselves and cause issues in other parts of the Southern Cal Gas System and potentially affecting all gas generation across the entire Southern Cal Gas System. And so that's why really we do believe that the risk is really more extensive than just the L.A. Basin. It really affects all the Southern Cal Gas resources in taking service from Southern Cal Gas Company, including San Diego.

And so that's why if you look at our analysis, our selection analysis, we are measuring the total amount of gas burned across all of the generation fleet that takes service from Southern California Gas. And that's why the measures are tailored to all those resources that are also taking service from Southern Cal Gas.

MR. FARROKHPAY: Cathleen, you mentioned that you are planning to start a stakeholder process to see which features you will make permanent in the third quarter of next year?

MS. COLBERT: Saeed, that is an anticipated. We've talked a lot through, and Anna largely as -- I'm going to defer to her on this.

MR. FARROKHPAY: I guess my question was, the provisions that you will file October 14, how long are they supposed to be in place?

MS. MC KENNA: That's a really good question, because I think we've confused that a little bit with our preview of what the world might look like in the future and how we might transition to that more on a permanent basis.

But for the purposes of Aliso, what we do know is we have the winter assessment now. We have also had the opportunity to go through the summertime period. And what we do know is that injections will probably not commence, and even if they do commence injecting again, the chances of having full functionality in Aliso next summer are not that high.

So what we are hoping to do is to request that these measures that are specifically tailored for the

Southern California system would remain in place through the winter and the spring/summertime frame so that we don't have to come back and do this again. Provided, however, if things went well in the spring, we would withdraw those and say okay, we don't need them anymore. But we think we have enough experience now to know we will probably need these measures through the summer again next year.

So we were hoping rather than coming back every quarter to ask for them, that we would just now take care of the winter and spring/summertime period, taking us again to the end of November, just to keep in mind that our summer goes a little bit further out on the west. So we're thinking to go at least to the end of November again. So that gives us a good chunk of time.

Now, if for whatever reason the wells are fully functional again or we have access to Aliso or other measures have taken place, we have improvements where we don't need them, that's fine. We can either withdraw them from the tariff, or we don't use most of this stuff.

But it is important for us to start planning for at least this annual period so we don't have to continuously come back and request it.

For the bigger picture perspective -- and Cathleen has been doing a really good job at managing a very complicated series of changes that are all sort of interrelated, we have foreshadowed that we are probably going to keep some of these Aliso-type provisions that are not a part of our other regular commitment cost efforts that are currently before the Commission.

So I don't want to get into all the details of those. But the ones that we think have been helpful and we can have as a part of our tool set, we're starting to think of how we could apply those throughout the system, given the changes on the security -- in terms of safety measures that have to happen throughout California.

These kinds of issues can now happen elsewhere. We think it might be prudent, and so what Cathleen is referring to is that next year, once we've had another at least winter season behind us in terms of how these measures work on the system, it would be a good time for us to start thinking about how we can extend those.

And you know, I'm really talking about the max gen constraint at this point, and the scaling will probably be addressed through our next commitment cost effort. So there's a lot of interplay. But the operational tools that we're using, enhancements on the coordination, all of these things might be better -- or might serve the whole system, not just Southern California. So that's what we're thinking.

MS. CASTRO: Thank you.

I think we're going to move on to -- we already covered 11 earlier this afternoon. So we will go on to agenda item number 12 with Bahaa.

MR. SEIREG: Just a quick question around, perhaps, a new stakeholder process. Is the ISO working with stakeholders to consider any near- or long-term alternatives that would include increasing nongas/electric supply or producing electric demand in areas that might be affected by Aliso Canyon's lack of availability?

MS. MC KENNA: Yes. Well, we didn't actually commence a stakeholder process directly related to Aliso Canyon, but we actually have had -- made a lot of improvements in accessing nongeneration type of resources in our system. And I just wanted to mention two achievements that recently happened.

The Energy Storage and Distributed Energy Resources initiative, also known as ESDER, not your Aunt Esther but our storage distribution efforts, that's going to provide us additional access to nongeneration resources. The Commission has approved that for us, and we're hopeful that's going to add as well some additional flexibility, not just in Southern California but throughout.

The other one that we think is also going to be very helpful, the other effort that's also been approved by the Commission, is the Distributed Energy Resource Provider initiative, an initiative known as -- I have to say it -- DERP, one of my least favorite acronyms. But that one also will allow us put a lot of our aggregation of distributed resources, again giving us more access to nongeneration resources. All of these efforts under play at the ISO currently being -- well, already developed, but in implementation form will provide additional opportunities for that.

So we didn't commence a new one for Aliso specifically, but we do think we have some tools in our tool box that will help us in that regard.

MR. ROTHLEDER: I should add, this is in our efforts at the CPUC for provisioning additional storage and demand response as a result of Aliso and those things are underway as we speak.

MS. CASTRO: Thank you.

MR. BARKER: Just one more. I would -- I'd be remiss if I didn't do a plug for what the Energy Commission has done. As small as the benefits may be, our chair wrote letters to all the state agencies that own property and run property down in Southern California, asking them to do any measures that they can to increase energy efficiency, demand response, PV, storage on those facilities. And he wrote that letter back in November.

I guess I would also note, in a follow-up to what Mark had talked about earlier this morning about everything that was done during the June 19th and 20th time of high heat wave, he also did follow up the Friday before asking them to do everything they could to conserve on those times. So he's used his responsibility as the chair to really push the state government buildings to do that.

We've connected also with the Department of Energy to just collaborate on seeing what can be done also on federal government buildings in the area and then also with the mayor's office in Los Angeles to see what they could do.

And one other thing I would note, we do have two research programs, one that focuses solely on natural gas, but then another research program on electricity. And we have had solicitations and will continue to do solicitations. In the past we probably would do for these demonstrations more state-wide. We've actually had that restricted to the affected area. So we've been even pushing some of our research programs to the restricted area.

MS. CASTRO: I will call on Pat for some follow-up questions.

MS. SCHAUB: A follow-up, probably for Kevin. As these policies get implemented, both to increase the amount of storage on the system and efficiency and demand response, is there a best transparent way to see kind of the progress that's being made? You've got a lot of transparency, for example, in behind-the-meter generation that's been helpful to us. Is there other ways we can kind of keep tabs on the progress made in these areas?

MR. BARKER: So for the -- as Mark mentioned, for the storage side, I think that's underneath the Public Utilities Commission. And I think they -- we have worked with associations like California Energy Storage Alliance to see what they could do to help facilitate that.

I believe also in the interconnection processes at the Public Utilities Commission, they are keeping track of actually anything that's behind the meter. And so we've been able to collaborate with them on data access to that.

MS. CASTRO: Thank you.

I do believe that we did cover agenda item number 13 earlier in the conversation today. So I do want to take the opportunity and open the floor. If there is any participant that would be interested in making questions or comments, please line up behind the microphone in the center of the aisle. And while we welcome your remarks, please try to keep them relevant to the topics discussed today in the agenda. Please state your name and affiliation, and if you receive a question or comment, if you have a business card, please leave it with our court reporter here today, Sara, who is on my right. Thank you.

MR. THEAKER: Thank you. This is Brian Theaker with NRG Energy again. First, I want to say we very much look forward to the ISO stakeholder process. It's something we think that has been long coming and we hope it will produce structural changes that we've been seeking for a long time.

Not to be pejorative, in our experience, the ISO's bidding system works really well except when it doesn't. It's intended to -- when prices are stable, the ISO's system works very well. When prices are volatile, it does not work very well, as we've found out to our detriment.

So just to point out some of the fundamental issues, you know, the market timing. I definitely have heard of ISO kind of dug in on market timing at this point. The reality is that when it runs its market after the timely cycle trades, if you can't predict your dispatch, you don't have think chance to transact in a timely cycle. And so you're subject to the intraday market, which in other OFO conditions can be a real difficult challenge.

Second, it's focused on using prices, lagging index prices that don't always capture, in fact they have very little correlation to where same day may trade. We find ourselves in the same-day market a lot. And so we think that's a mismatch.

Third, with commitment costs, the 25 percent cap, generally, it's not a problem, although arguably it represents a cap that presumes the exercise of market power when market power hasn't been demonstrated. So it can be problematic under some circumstances.

Fourth, we do appreciate greatly that the ISO has filed or and received permission for after-the-fact cost recovery. That's a great thing. It's a mechanism that hasn't been tested yet. We're not anxious to be the first. We're looking forward to -- if that process happens, it happens, but we still feel uncertain about exactly how that's going to play out.

And then finally, as we've talked about a number of things, we always believed that the ISO has a chance to improve the transparency. Dede talked about this procedure whereby the ISO will allow flows or will be able to rerate Path 26 dynamically in real-time. That's great. The ISO's market is really premised on having accurate information to its market participants with regard to transmission constraints and limits. So we would like to see that this rerating process be exercised in a transparent way using criteria that are defined up front.

Just in summary, we appreciate the Commission's attention to this. We appreciate what the ISO has talked about, and we very much look forward to participating in the stakeholder process.

MS. CASTRO: Thank you, Brian.

MS. KARAS: Hello. Natalie Karas with the Environmental Defense Fund. I just wanted to echo some of the concerns that Brian just noted and take a bigger picture view of the market.

We support the concerns that NRG, WPTF, and others have raised regarding market inefficiencies, and we want to be working with the CAISO going forward. So we look forward to the stakeholder process, and I was wondering if there's a set timeline for that process, because it's my understanding that these issues have been raised by NRG and others dating back to 2014. So I'm curious as to the timeline for that process.

MS. CASTRO: You're welcome, CAISO, to respond.

MS. COLBERT: Okay. Great. Thanks.

Can I just ask a clarifying? When you say "timeline," are you curios what -- of initiating the process?

MS. KARAS: I understood that it was starting in the third quarter of 2016. But in terms of getting it to FERC, what is the FERC filing timeline?

MS. COLBERT: So -- and I ask for your understanding that before we launch an initiative, it is very difficult to say what the completion date would be, especially until the first paper is out.

So on the new initiative, the commitment costs and default energy bid enhancements, at this time I don't think we can supply an end date, but I can say that that is probably going to be launched -- it's being reviewed now. And so it should be launched within the next week or two. It is an as soon as possible kind of initiation. And once we go through the issue paper phase, once we move beyond that, we'll have a better assessment of the timing on it. But it's just too premature on that.

The second process we talked about earlier would be a different initiative that would come later after we've gone through winter, looking at some of these operational tools, if it might be needed to help manage the system.

MS. KARAS: Thank you for that explanation. I also had a question, when you were talking about aligning the timely gas nomination cycles in the day-ahead market, you said that during the stakeholder process you felt that -- you looked at the costs and benefits, and you felt that the costs outweighed the benefits.

So was there a formal analysis, quantitative analysis of that, or is that just a qualitative discussion among stakeholders?

MS. COLBERT: That's also a really good

question. It was qualitative; it wasn't quantitative. There were a couple stakeholders, one or two, that supported considering moving. But the vast majority vehemently opposed it, as well as internally.

So from a qualitative perspective, it didn't even really warrant the deeper analysis.

MS. KARAS: Okay. And my next question is actually following up on something Patricia said, but I want to ask it to the CAISO in terms of the demand response.

I know, Mark, this morning you said that, I think, CAISO relied on 1,000 megawatts of demand response during -- I can't remember the time frame. But I'm wondering, in terms of, is there a transparent way for us as stakeholders to better understand how demand response is being used as a tool to address the limited availability of Aliso Canyon?

MR. ROTHLEDER: So I think that was in our material we made -- and I'm sorry. I don't have the material here -- in a presentation to -- in Southern California. And we can provide that to you. But the 1,000 megawatts approximately was both a combination of demand response and flex alert estimated response.

MS. KARAS: Okay. I look forward to those materials. Thank you very much.

MS. CASTRO: Next speaker up to the microphone.

MR. MOSLEY: Hi, I'm Berne Mosley. I'm here on behalf of Magnum Storage, it's a storage facility in Utah. It has a FERC certificate which is currently being amended here at FERC, and it's not contested. So we don't have to worry about that.

I know it's after the allotted time. It's Friday afternoon. So I'm going to do this really quick. And I have a question that concerns the use of storage from other states, obviously, in meeting some of the demands for California. And it may be that information may come out next week in your 21st and 22nd release of the long-term planning. Have you considered gas deliverability in lieu of the availability of storage such as Aliso or if regulations may be temporarily halt the use of other storage in California?

MS. MC KENNA: This is Anna. Is that a question to the ISO or is that question more to the gas pipeline company?

MR. MOSLEY: It's more just for planning purposes in light of the unavailability, at least in the near term, of Aliso and potentially other storage facilities.

MR. SUBAKTI: Was it the energy storage, or was it the gas storage?

MR. MOSLEY: I do have a question on energy storage, but this is natural gas storage first.

MR. SUBAKTI: Thank you for the clarification. That's probably more a gas question.

MS. MC KENNA: We're not really experts on the gas system. I don't want to insult any of my colleagues. I'm not an expert. But I think it's a question that maybe SoCal can respond to or others that have more expertise as to how the gas pipeline systems might access a Utah storage facility, if that's what you're asking.

MR. MOSLEY: In general. Obviously, I'm specifically asking about Utah specifically but in general.

MS. MC KENNA: I think it depends on the system.

MR. ROTHLEDER: I think I know enough right now, not all storage facilities are alike. It does depend on where they are, their withdrawal capability, and they are different. And I think in our transition planning assessment, we will be considering the role of other storage facilities in California certainly because they are effective of mitigating at least -- depending where they are, mitigating measures to local generation.

In terms of the broader storage facilities across the west, I think that's probably more of a commercial question about how those could be used to help shore up supply availability coming into the system. So I can't speak to that one.

MR. MOSLEY: Okay. Thank you. If you will indulge me one more quick question to Kevin about energy storage. Similarly, would you consider energy storage out of the state?

MS. MC KENNA: The question is, would the ISO markets be able to consider energy storage that is out of state for purposes of clearing its market?

MR. BARKER: So I guess were you directing that at me? So what we're looking at as far as preferred resources, we're focused just on the affected area of Aliso Canyon. I guess similarly to what Mark was saying, but however on the electricity transmission system, to the extent that electricity storage from out of state can help with import supplies that would no -- would otherwise not be available, that's not really something in my bailiwick.

MR. ROTHLEDER: I guess I could say that both through the energy imbalance market and the potential opportunities for regional integration, I think the prospect of making use and the opportunity for using resources across the west, including potentially storage located in other parts of the west become an interesting and, I think, potential opportunity question. So I think there is something to think about in the longer term there, both in terms of, I guess, regional coordination.

MR. MOSLEY: Thank you.

MS. CASTRO: Thank you.

I think this will be the last speaker, as we're beginning to run out of time.

MS. GEORGE: Good afternoon. I'm Simi George with the Environmental Defense Fund. I wanted to follow up on a question my colleague, Natalie Garris, asked about demand response and CAISO's efforts to better explore demand-side alternatives.

And I appreciate Anna's response earlier on the ester process and on the NERC process, but knowing those to be not specific or informed by Aliso Canyon, certainly it was an effort to predated Aliso. If you could give a little bit more color about CAISO's kind thinking on how you might be able to -- informed by the Aliso situation, explore demand-side alternatives more thoroughly.

And my second question is, similar that, given that these are both somewhat distinct, discrete recognized approaches or processes, are you considering a more holistic consideration that goes beyond these two specific processes?

Thank you.

MR. SUBAKTI: So I'll try to address that. In California ISO, right now -- Mark talked a little bit about our effort in the transmission planning. The transmission planning is coming up really soon, and out of that, we are also looking at the impact of the local capacity requirement that I earlier talked about Saeed.

So what this leads to is this leads to us looking at what would our local capacity requirement in the Southern California area, in the San Diego area, in the L.A. Basin area, and that would set what we call the local capacity need for the area.

Now, we are looking for transmission installation, such as condensers, that's already been approved, 500-kV line that has been approved as well. That portion is going to reduce the local capacity requirement in that particular area. So that is the infrastructure that's being built in there.

Now, we are also working to basically work on what are the resources that can meet that local capacity requirement. And that would include the -- there's a discussion currently with the role of demand response, both the fast-moving demand response as well as a slow-moving demand response and how both fast-moving demand response and slower moving demand response to meet local capacity requirement.

One of the challenges that we have is that, because the fact that local capacity requirement is set by the need in the transmission capacity, there is timing requirements along with that. So for example, FERC and NERC have reliability standard that say that every -- you know, things like voltage stability which has a relation to Interconnect Reliability, the IORL, those need to be mitigated within 30 minutes.

So then the question becomes if we need to mitigate a transmission emergency problem within 30 minutes, what kind of demand response can we get to actually meet within that 30 minutes' time frame that the reliability standards require.

So there is an interplay on how we look at the demand response for local capacity requirement, how we look at the fast-responding local -- fast versus slower, probably like four hours demand response and whatnot.

Hopefully that answers the questions.

MS. GEORGE: Thank you. That answers my first question. I had a second follow-up question on whether there's a more holistic examination beyond the two discrete policies that Anna McKenna mentioned before, looking at demand-side alternatives.

MS. MC KENNA: I'm not aware of any ISO holistic or -- I'm not quite sure how to answer the question. I think when we do start a stakeholder process, we do look at the issues holistically as best we can within the context, issues identified.

But if you're asking, do we have a stakeholder effort that looks to specifically expanding demand response programs at the state level -- is that what you're asking?

MS. GEORGE: Yes, that's right. So you mentioned the two milestones, and I was wondering if there's something going broader beyond those two initiatives that's being contemplated, especially given the Commission's June 1st order which essentially laid out a directive to explore to the fullest extent possible how these alternatives can be better applied.

MS. MC KENNA: We've put a lot of effort into using our demand response programs as much as they are available to us to the extent that we can. Some of the numbers you heard today are as a result of that. We don't have a stakeholder process that looks at demand response as a specific issue overall. But there are various efforts at the PUC that we get involved with when these issues come up, we are actively involved in stating how that impacts our system, providing feedback in that area.

And we do actually participate quite actively, and I did mention a couple of the stakeholder processes that we already have done that will increase availability resources. But there isn't a stakeholder process that is intended to launch, without definition of an issue specifically, beyond that.

MR. ROTHLEDER: There has been ongoing stakeholder processes for improving distributed energy resources generally, and we've been kind of addressing issues as they evolve.

And I think in that regard, we're also looking at how we enhance the coordination between the transmission system and distribution system operator as there becomes increased active resources in the distribution system. That's an ongoing effort and in various locations, and we're also staying in tune with that and proposing changes as necessary to support the distributed energy resources being able to provide services to the transmission system operator.

MS. GEORGE: Thanks for that response.

MS. CASTRO: Thank you.

As we close this afternoon's session, this concludes our agenda for the afternoon. I would like to thank everyone for their participation in today's technical conference, especially our guests who have come from California, CAISO and the CEC. We appreciate you flying out to the East Coast to join us here.

Just as a reminder, transcripts are available for a fee from Ace reporting company, and a link to the Webcast of this event will be available on the Commission's calendar -- in the Commission's calendar of events at

FERC.gov.

I would like to wish everyone safe travels home and a wonderful weekend. This concludes our technical conference. Thank you.

(Whereupon, at 3:46 p.m., the technical conference was concluded.)