DOCKETED	
Docket Number:	21-IEPR-04
Project Title:	Energy Reliability
TN #:	240856
Document Title:	Transcript of 7-9-21 for Joint Agency Workshop on Summer 2021 Electric and Natural Gas Reliability - Session 3
Description:	JOINT AGENCY WORKSHOP ON SUMMER 2021 ELECTRIC AND NATURAL GAS RELIABILITY, Session 3 - Gas Reliability and Polar Vortex Impacts & Implications
Filer:	Raquel Kravitz
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	12/6/2021 6:56:33 PM
Docketed Date:	12/7/2021

JOINT AGENCY WORSHOP

BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the Matter of:)
)
2021 INTEGRATED ENERGY POLICY) Docket No. 21-IEPR-04
REPORT (2021 IEPR))
________________________) RE: Reliability

JOINT AGENCY WORKSHOP ON

SUMMER 2021 ELECTRIC AND NATURAL GAS RELIABILITY

REMOTE ACCESS WITH ZOOM

FRIDAY, JULY 09, 2021

10: 00 A. M.

Session 3: Gas Reliability and Polar Vortex Impacts &

Implications

Reported by:
Marlee Nelson

APPEARANCES

Workshop Leadership

Andrew McAllister, CEC Commissioner
Siva Gunda, CEC Commissioner
Karen Douglas, CEC Commissioner
Patty Monahan, CEC Commissioner
Martha Guzman Aceves, CPUC Commissioner
Clifford Rechtschaffen, CPUC Commissioner
Elliot Mainzer, California ISO, President and CEO
Darcie Houck, CPUC Commissioner

Staff Present:

Heather Raitt, Program Manager
RoseMary Avalos, Public Advisor
Jennifer Campagna

Presenters:

Melissa Jones, CEC
Brian Walker, SoCalGas
Kristina Abadjian, CPUC
Joseph Long, Aspen
Anthony Dixon, CEC
Jean Spencer, CPUC

Public Comment

Norman Peterson, Southern California Generation Coalition
Todd Peterson, Pacific Gas and Electric

I N D E X

P R O C E E D I N G S

JULY 9, 2021 10:00 a.m.

MS. RAITT: All right. Well, good morning, everybody. Welcome to today's 2021 IEPR Joint Agency Workshop on Summer 2021 Electric and Natural Gas Reliability. I'm Heather Raitt, the program manager for the Integrated Energy Policy Report, or IEPR for short. Todays workshop is being jointly held by the Energy Commission, the California Public Utilities Commission and the California Independent System Operator. This is the second day of our two-day workshop.

This workshop is being held remotely consistent with Executive Order N-08-21 to continue to help California respond to, recover from, and mitigate the impacts of the Covid-19 pandemic. The public can participate in the workshop consistent with the direction and the executive order.

To follow along today, presentations that are being presented by panelists have been docketed and posted on our website. All IEPR workshops are recorded and both a recording and written transcript will be linked to the CEC's website following the workshop. Attendees have the opportunity to participate today in a few different ways. For those joining through the online Zoom platform, the Q&A feature is available for you to submit questions. You may also upvote questions submitted by someone else. To do that click the thumbs up icon. Questions with the most upvotes will move to the top of the queue.

We'll reserve a few minutes near the end of the session to take questions, but likely will not have time to address all of the questions submitted. Alternatively, attendees may make comments during the public comment period at the end of the morning and afternoon sessions. Please note that we will not be responding to questions during the public comment period. Written comments are also welcome and instructions for submitting them are in the workshop Notice which is available on our website. Written comments are due on July 23rd. And with that, I'll turn it over to Commissioner Andrew McAllister to begin opening remarks. Thank you.

COMMISSIONER MCALLISTER: Great. Thank you very much, Heather. I'll be very brief, but welcome, everyone. I really appreciate everyone's attendance to the second day of workshops on Reliability within the Reliability track of this year's Integrated Energy Policy Report. Again this year -- this day, we have a full dais and really appreciate our colleagues from the California Public Utilities Commission, as well as the Cal ISO. And I just wanted to highlight that we had a great day of workshops yesterday around Electric Reliability, really highlighting the key issues at the moment. Certainly climate impacts hover over everything as just a major, major factor in our planning going forward, hydro resources and other elements of what we have to do for near and long term planning going forward on the electric side.

Today, we're going to switch to the natural gas and highlight a bunch of key issues there. Certainly the gas reliability and again, climate impacts, the polar vortex, and then around issues around Aliso Canyon and our gas planning around that. So, you know, the electric and gas sectors are so intimately linked, sort of twins really, inextricably linked as we go forward in our planning, ever more so. And so, really key to have a situational awareness across both elements and understand the bridges between the two and how we can plan intentionally around their coevolution. So today we're looking forward to getting into these issues.

I want to thank my colleague, Siva, Commissioner Siva Gunda, who is the lead on reliability. And again, all of the staff here, Heather and her team on the IEPR team here at the Commission and the Assessment Division team, who has really driven this series of workshops under the leadership of Commissioner Gunda. And forthwith, I will pass it off to you, Commissioner Gunda, for some opening comments and so we can get started. So thank you very much.

COMMISSIONER GUNDA: Thank you, Commissioner McAllister. Thanks for setting the stage for today. Again, I just want to also recognize everybody that's here, and all of the stakeholders, public participants, the staff, but also the leadership from both CEC, CPUC, as well as ISO. So thank you, everybody, for being here. As Commissioner McAllister mentioned, I think yesterday was a pretty sobering day for a number of us. I think it's just kind of a continued recognition and realization of the impact of climate change. We talked about the hydro conditions, the uncertainty of hydro conditions moving forward and what that means for our energy system planning. We talked about, at a high level, what it means from an import standpoint. You know, how does the West, as it continues to decarbonize, how that puts impact on one of the resources we all rely on, which is imports for our electricity system planning.

On the top of that, we also recognize some of the ongoing collaboration between CPUC and CEC, particularly around DR, Demand Response, the future of demand response planning, and also the planning around the resources that we need through 2026. So, again, incredibly thankful for staff and the leadership across the agencies for setting the tone of collaboration. And I mentioned yesterday, I think we all have very distinct functions. We have our own streamlines of topics that we cover. But as we all try to endeavor to succeed California and make sure that reliability and safety is at the center for all Californians, we cannot do that, any one agency, and that is why you're seeing this collective work. And, you know, that our collective success is the success of the State. So I'm really thankful, again, to all the members. I want to provide a special recognition to Commissioner Martha Guzman Aceves, who is here from CPUC. Much of today's workshop will be dealing with, as Commissioner McAllister pointed out, the natural gas reliability, but also the interconnectedness between the natural gas and the electric system. She really is kind of taking a leadership role in planning this afternoon sessions, particularly. But without further ado, I want to really pass the baton to Commissioner Guzman Aceves to set the stage for today and then kind of open it up for remarks from other Commissioners CEC and CPUC.

COMMISSIONER GUZMAN ACEVES: Thank you, Commissioner Gunda. I want to thank everyone also for all of their collaboration and thank all of our staff as well. I think you are so correct that yesterday obviously highlighted, in a very condensed way, many of the issues we know are out there, particularly with the drought. And I think today is another dynamic, which is not only do we have to make sure we have enough reliability for today and moving into tomorrow with our new climate, but also the interplay and the dynamic of our dependency on natural gas and how our transition off of that is also going to make it an extra challenge. And as you've mentioned earlier, all of you have mentioned earlier, the importance of making sure that this transition is not regressive and that we have an equitable transition. And it's most keen when we're talking about how we do this with natural gas, including on our generation dependency.

So I want to thank you for this. I certainly hope it's not -- it's not even the beginning, but we're kind of in the middle of this discussion, and I know we'll have much more iteration. I really look forward to hearing from our panelists and from the public on how we continue to look at all the dynamics and aspects that we're not yet capturing so that we can make sure this transition is, as we said, equitable, and safe, and reliable. So with that, I turn back to you.

COMMISSIONER GUNDA: Thank you, Commissioner. So with that, I don't know if anybody else from the dais would like to make comments. Looking for, Commissioner Houck, looks like you might want to make some comments.

COMMISSIONER HOUCK: Just really briefly, I'm sorry I wasn't able to be here yesterday. I was able to listen in on part of yesterday afternoons presentation and agree that we've got a lot of challenges that we've got to look at. And the PUC just recently opened a rulemaking looking at distributed energy resources and I think it's very timely to see that so that we can start looking at how we can overcome the challenges with incorporating distributed energy resources into our reliability toolkit. And hopefully, it won't be this summer, but we're hoping to come up with some answers and I'm looking forward to working with the Energy Commission, the ISO and my Bagley-Keene partner, President Batjer, and hoping that we can help add some new tools to that mix. So I won't be able to be here this afternoon, but I appreciate and thank you for inviting me to be part of the meeting this morning.

COMMISSIONER GUNDA: Thank you, Commissioner Houck. I would like to, yeah, call on the Commission Rechtschaffen.

COMMISSIONER RECHTSCHAFFEN: Yeah. Thank you, Commissioner Gunda. I don’t -- I joined a couple minutes late. I don't know if it was mentioned that President Batjer may not -- probably won't be able to join us today. She got pulled into some emergency meetings. I just want to -- because she is closely following. I'm hoping at the end of the second day, I could become an -- I could become an honorary California Energy Commissioner. If I -- I think it's like for those 10 card things at the yogurt shops, if I come to 10 IEPR meetings in six months, maybe I can become an honorary CEC member. Do you think that's possible, Commissioner Gunda?

COMMISSIONER GUNDA: It's definitely above my pay grade, but I'm pretty sure Commissioner McAllister and Commissioner Douglas can make it happen.

COMMISSIONER RECHTSCHAFFEN: Okay.

COMMISSIONER MCALLISTER: Look, I think it's more like a buy ten, get one free.

COMMISSIONER RECHTSCHAFFEN: Okay. Good. I can help at the next IEPR for free. But anyway, I'm very much --

COMMISSIONER MCALLISTER: Yeah. Exactly.

COMMISSIONER RECHTSCHAFFEN: -- discussion for all the reasons that my colleagues have articulated so far.

COMMISSIONER GUNDA: So Commissioner Rechtschaffen, just to kind of react to what you just said, I think, you know, the kind of the gentle, kind of fun spirit tribute to what you just said, but also, I just want to take a moment to recognize like your continued presence at these workshops over this year, in both the Building Decarbonization, the Resource Planning, and now the Reliability. Just incredibly appreciate your leadership on these issues and your continued participation.

So with that, I'll pass it back to Heather unless President Mainzer wanted to say anything. I don't -- I don't see him.

PRESIDENT MAINZER: I'm just fine. Thank you, Commissioner. Looking forward to the proceedings and thanks again for hosting an excellent session. Much appreciated. Thank you, Mr. Mainzer. With that, back to Heather.

MS. RAITT: Great. Thank you. So we'll start off this morning with a series of four presentations on Gas System Reliability and its Relationship to Electric System Reliability. And the first presenter is Melissa Jones. She's a senior policy specialist with the Energy Commission's Energy Assessment Division, and so she'll be giving an overview on Gas Reliability and the Interdependence with the Gas and Electric Systems. So go ahead, Melissa. Thank you.

MS. JONES: Great. Good morning, everyone. I am Melissa Jones, and I'm happy to be here today. There are two areas of focus that have been identified in the IEPR Scoping order. Two areas including Situational Awareness of the Emerging Topics in Natural Gas System Planning and then Refining and Developing Critical Analytical Products necessary to do that gas planning.

Today’s workshop is going to be focused on Gas Electric Reliability. We'll be having presentations on December 2021, Gas Reliability Assessments for Southern California. We’ll then have a review of the event that occurred during the winter 2021 called the Vortex Storm Uri event, and this afternoon we will be talking about Alternatives to Aliso Canyon that Ensure Reliability. I also wanted to mention we've had one workshop in May on Infrastructure. We anticipate having a number of other workshops related to gas, including on the Gas Demand Forecast and Rate Forecast; Long-term Demand scenarios. We'll be having a session on Renewable Gas and also one on Hydrogen.

The Warren-Alquist Act does ask us to analyze all aspects of natural gas, including forecasting, assessment, supply, demand, price, infrastructure, market, and all related topics. This analytical foundation is what we use for policy development in our IEPR.

One of the reason why I’m doing this overview this morning is that gas issues haven't been a major focus of IEPRs in the last few years. Electricity issues are typically front and center. We want to start familiarizing our IEPR stakeholders with the gas system, with gas issues, and gas analytics. Today, the focus will be on the nexus between gas and electric system reliability. Next slide, please.

So as Commissioner McAllister stated in the opening remarks, the gas and electric systems are very interdependent. For several decades natural gas has been the workhorse of the gas system, or of the electricity system, excuse me. And it's been a dominant resource on the electricity system. But we're seeing rapid growth in solar and wind, which is now shifting the role of that electric generation is playing. And it's moving towards integrating renewables on the grid. Am I on the right slide?

MS. RAITT: Actually, Melissa, you're on -- Raquel, can you go back one slide, please? Thank you. Sorry Melissa, go ahead.

MS. JONES: Okay. So we have had a large increase in renewables and so electric generation is moving to integrate those. Gas system operations are shifting to accommodate the afternoon/evening ramps on the system and the net peak as the sun sets, but we all have to remember that electric generators get curtailed when there's insufficient gas to meet all of demand in both cold weather conditions and under constrained system conditions in Southern California and other areas. And we're beginning to see more demand in the summer, at least peaks on the system in this new role of integrating renewables. These two systems are deeply linked. Events and conditions in one have significant impact on the other, and with the large increases that we're anticipating in renewables over the coming decade, we think the electric generation demand is going to be the driver of gas system needs and operations as we move forward. Next slide, please.

Just a little bit of background on the role of the gas fleet; project a gas-fired power plant as the new workhorse of the electricity system. In 2001, gas accounted for about 56% of in-state generation. It declined to about 52% in 2010. And then in 2020, it was 48%. It's still a very significant part of the generation. At the same time, renewable resources have increased dramatically from about 14% in 2001 to 31% in 2020. The other thing that natural gas generation has provided for the system is filling the swings in hydro. When there's drought, we tend to burn more natural gas, and to show you the extent of this swing, between 2001 and 2020 natural gas generation went, it sprung, from 86,000 megawatt hours to 121,000 megawatts hours. That's a very big shift in generation. But we are starting to see renewables that are starting to fill in for that swing in loss of hydro, starting around 2015, but again, gas is going to continue to play an important role of the electricity system, at least in the near-term and to some extent into the midterms. Next slide, please.

So Southern California has been experiencing reliability challenges through the last decade. These sort of emerged in 2010 as we identified concerns with implementing the OTC policy, the Once-Through Cooling policy that affected about 20,000 megawatts of electricity generation in the State. These are power plants that are located along the coast. So we were planning for their retirement, and then in 2012, there was the unplanned retirement of San Onofre, which just exacerbated our challenges. And because of its role in maintaining grid stability in Southern California, it was a major concern for us. And the three agencies, along with the gas and electric utilities, began to coordinate and really try to -- try to avoid having to curtail or end up with blackouts on the electricity system. And then in 2015, we had the Aliso Canyon leak. This reduced the amount of storage and presented a new set of challenges for both the gas and electricity system. And then recently in 2018, we had several pipeline outages on SoCalGas system and that just made their problem worse. We did have some gas curtailment, and of course we had very significant price spikes. Next slide, please.

Aliso Canyon, well so here's prices. These are historic prices, and you can see from the black, two black lines that in -- that starting in 2015, we began to see increasing gas price volatility, the risk of curtailment increased, and there was reduced instability of infrastructure. But the limitations on the use on Aliso began and then as I said, the two pipeline outages, lines 235 and line 4,000 in SoCalGas were out. You can see how price spikes occurred following that. The most recent price spikes that we've seen were in February 2010, or 2020. Excuse me. And these were related to the Storm Uri event, which we'll talk about a little bit later this morning. Next slide, please.

So just quick review on Gas demand in California. There are two types of gas customers in the -- in the gas world. There are core customers, which are generally residential and small commercial. There are also non-core customers, which are the remainder, the industrial customers, large commercial electric generators. The two types of customers matter when it comes to reliability standards because the standards are different for these two classes. So residential and small commercial demand, the peaking demand is generally driven by space and water heating. In the commercial sector we have rest -- we have a whole variety of end-uses and types of businesses, restaurants, educational facilities, commercial laundry, health care, food processing. In the industrial sector we see gas used as fuel and for process heat. And then, as I just explained, electric generation, there is a reliant there for system reliability and renewable integration.

We also are increasing the amount of gas that we're using in CNG and RNG fueling stations. And then, of course, transportation fuels. We have the oil refineries for our big use of natural gas. And all of this use-gas is delivered to customers via an extensive infrastructure system. Next slide, please.

Just to give you a sense of how much demand is attributed to each of the sectors, this shows gas demand trends over the last 22 years. So we have actually been seeing declining gas demand starting in about 2012, 2013. I should note that that annual variations occur depending on weather. PG&E and SoCalGas are forecasting a decline of about 1% per year out to 2034. This is based on their older forecasts. They recently filed new forecasts, but we're still in the process of reviewing those. We will be updating those as we move through the IEPR process. As I mentioned, weather is a big driver for residential and commercial, but it's also a big driver for electric generation.

To give you a sense of the magnitude, residential consumption’s about 23% of gas demand while about 75% is made up of industrial or commercial and electric generation. And as I mentioned earlier, renewable integration is likely to increase gas demand in the near-term. It will probably be driving increased spikes on the system or increase ramps on the system, which operators will need to figure out a way to begin to handle. It’s a different way of operating the system. So next slide, please.

Just for a quick review on gas reliability standards. So the PUC sets gas reliability standards that address the physical capabilities of the gas utility system. These standards assume a combination of both gas flowing through the intrastate pipeline and withdrawal from storage fields to balance supply and demand. And unlike electricity, which is transmitted almost instantaneously, gas flows through the system at about 25 or 30 miles per hour. And the way that gas is delivered under tariffs is on what they call a ratable or ratable basis, which means there's a constant flow on supply that’s spread evenly over the 24-hour period.

But what we know is that electric generators with frequent starts and stops and with these large ramps, they're taking larger amounts of gas over shorter periods of time on the system. Gas utilities met core customer demands on a very cold winter day, again, driven by space and water heating. The gas utilities meet a lower winter peak demand for non-core customers. These customers are willing to accept a risk of occasional curtailment in exchange for a lower rate. And storage has been a key element of the system in providing reliability and also minimizing the risk for curtailment and severe price spikes. Next slide, please.

Quick review on intrastate gas infrastructure. The -- so we have the storage fields that are operated by three sets of operators. We have two investor owned utilities, and we also have independent storage operators. In the -- on the map, the red circles indicate storage and PG&E has the Los Medanos, and McDonald Island, and Pleasant Creek storage fields. SoCalGas has Aliso Canyon. Also Honor Rancho, La Goleta, and Playa Del Rey. In terms of independent storage operators, they operate Wild Goose, Lodi Gas, Gill Ranch, and Central Valley Storage. You'll also see an extensive set of black lines, which are the interstate pipelines that connect at the borders of the State to bring it interstate flows of supplies and deliver them to those load centers. Next slide, please.

Just a reminder that we are a part of a large web of infrastructure in the Western United States who get most of our gas from over a thousand miles away. We are at the end of those pipelines. We get about 90 percent of our supply out of interstate transmission pipelines. It comes from Alberta, Canada, also from Southern Wyoming. We get gas from the San Juan Basins, in Northwest Mexico, from the Permian Basins in West Texas and Southeast New Mexico. And then the Receipt Point for these pipelines at the California borders; up in the north, it's at Malin. In the South it's at Topoc North and South, and then Wheeler Ridge is where Kern River Interstate Pipeline connects to California. PG&E, generally, is more reliant on Canadian gas, while SoCalGas relies primarily on San Juan and Rocky. Next slide, please.

So in terms of ensuring gas -- core gas reliability, the gas utilities do purchase gas and provide transportation storage services for the core customers. The winter peak demand for residential and commercial has driven the need for infrastructure, including pipelines, storage, and other infrastructure. And as a result, the allocation of those assets to the rate reflect that greater use. Strict reliability standards are designed to meet core demand under very, very extreme conditions without interruption. For SoCalGas, they use what they call an exchange peak day, which is an event of a with a 1-in-35 probability of occurrence. For PG&E, they use what they call an abnormal peak day, which for the core is a 1-in-90 probability of occurrence event. Next slide, please.

So curtailment of core customers is considered an option of last resort in maintaining system operations. The reason for this is that restoring core gas services can take several days, up to weeks, and it involves a tremendous amount of manpower. Gas mains have to be bought back individually and sequentially. Services to each home or building has to be safely restored. Utility or other people have to go to each home and light the pilots, which means that a person has to be at that household. And there are safety concerns and potential for explosion. Pilot lights can flicker out inconsistently is line pressures drop. And if there is not proper restoration of the system, then there are safety risks there. Next slide, please.

So in terms of noncore reliability, the noncore reliability standard is for a cold winter day with a 1-in-10 probability of occurrence, and it also factors in dry hydro conditions for electric generation. As I mentioned earlier, when droughts occur, we end up relying more on natural gas. The standards assumed, when were originally established, that noncore customers had alternative fuels such as distillate or diesel fuel. That's no longer the case in the State. There is not this dual fuel capability, largely due to air quality regulation. And so this poses an interesting dilemma for these customers in that they do face curtailment. Noncore, I should just say that the electric generators do take the gas off the system, as I noted before, when they're dispatched by the electric system operators. And this new demand pattern is the key example of the interdependencies that we see between the gas and electric system. Next slide, please.

So just this is a histogram that shows the last 22 years, see all of the peak days -- all of the peak days during that occurrence, or during that period. And what we see here, memories about temperatures and about weather are particularly untrustworthy. We tend to forget them fairly quickly. But on a cold day, PG&E demand is about 3.6 Bcf. And so that's shown by the orange line. And then the 1-in-90 core and the 1-in-10 noncore are shown in the gray line. And what you see on this graph is that there have been 95 days during this period when it exceeded the 1-in-10 core noncore demand.

And there were 13 days when it was above the 1-in-90 core and the 1-in-10 noncore demand. These are things that review their rare events, but they are very disruptive and they're things we have to think about. We will hear more about that later today. And when those days are above that 3.6 and 4 Bcf, it does result in curtailments, which tend to degrade electric system reliability and it also disrupts industrial processes and operations that are important to the state’s economy. Next slide, please.

This is the histogram for SoCalGas winter peak demand, which is about a little under 5 Bcfs per day on a very cold, abnormal day. SoCalGas experienced three days that were greater than that 1-in-35 core and 1-in-10 noncore. And eight days where it exceeded the 1-in-10 and core and noncore. Again, on these days, noncore curtailments would be expected, and the implication of this is if we lower reliability standards, what we're doing is we are just increasing the number and risk of curtailments that we’ll face. Next slide, please.

So there’s a number of issues we'll be facing in terms of planning system that acknowledges this important gas electric reliability interplay. Historically, if the winter standards can be met, it's the assumption that summer reliability could be met. Summer demand’s generally been lower than peak demand, and while flow through the pipelines maybe lower overall, it's again, these peaks that are going to drive the need for infrastructure in the future and drive the need for changes in the way the systems are operated. And we do have these larger ramps and the peak and net peak loads that we have to meet on our system until gas plants play an important role there.

We are going to have -- going to need to place more emphasis on the impact of extreme heat on electric generation demand. And the -- as one of the difficulties we face with high summer peak demand on the electric generation and gas system is the ability to inject storage to prepare for the following winter. We think that the future gas use will depend, to a certain extent, how quickly we can deploy low carbon technologies to displace gas. We also need to assess how the electric system demand is going to change with electrification of buildings and transportation, which may increase winter peak. And as we learned in February, we also need to place more emphasis on the impact of extreme cold events like the polar vortex. We've seen these, a number of these, over the past 20 years and with climate change, we anticipate these extremes to continue. And next slide, please.

With that, I'm happy to take any questions.

MS. RAITT: Thanks, Melissa. This is Heather. I think we'll move on to the next speaker and hold questions for the end, if that's okay.

The next --

MS. JONES: Okay.

MS. RAITT: Great. The next speaker is Brian Walker. He's the director of Gas Control and System Planning for SoCalGas. Go ahead Brian.

MR. WALKER: Okay. Hello and good morning. We could go right to the next slide, please. I'll talk a little bit about our service territory. It goes from the Visalia to the north, to the Mexican border to the south. We cover 24,000 square miles where our system delivers gas to 21.8 million customers through 5.9 million meters. Next slide, please.

Our system takes in supplies from upstream suppliers at 10 different receipt points in local California production zones across our service territory. We also have the four natural gas storage fields. The SoCalGas and San Diego Gas and Electric gas transmission system is nominally designed to receive up to 3.78 billion cubic feet per day, flowing supply on a firm basis. This means that if customers deliver that much supply to the SoCalGas system and there are sufficient customer demand, then SoCalGas can redeliver that gas supply to customers. So supplies delivered to the SoCal system, however, do not reach these maximum receipt levels for a variety of reasons, such as maintenance on our system or upstream pipelines, customers using balancing services, decline in California production and demand not necessitating the maximum delivery, in addition to just availability of upstream supplies. So with that we go to next slide, please.

And on slide four, we're going to touch a little bit here on Winter Storm Uri. I know there's more later on this in detail. So from February 13th to 18th, the polar vortex over the Midcontinent impacted natural gas deliveries to the SoCalGas system. However, coincidentally, Southern California was experiencing moderate weather for the winter in comparison to the Midcontinent, so our demand was quite moderate during this time. The inclement weather, however, in the Midcontinent, it impacted what we can receive from the Permian Basin. And we saw our pipeline Receipt Point Utilization drop to approximately 47%, which is very low. Specifically in our Southern System is where we were mostly impacted at our Ehrenberg Blythe receipt points where customers were nominating gas supply to come there, however, it was not being scheduled because of the supply limitations upstream of the SoCal system.

So in response to the underperformance and low supply into the Southern System, SoCalGas and San Diego Gas and Electric issued a curtailment watch for the Southern System. In particular because it has limited access to gas supplies from other parts of our system. So it was more significantly impacted by the, well freeze offs and the impacts in the Permian Basin. So with the low pipeline receipts, the gas system was reliant on stored field withdrawals. And that is really the story of the event. A lot of gas was pulled out of our storage fields to support the system throughout this event in the Midcontinent. Also wanted to note that Condition 1 of the Aliso Canyon withdrawal protocol was met throughout the event, which provided access to withdrawal from Aliso Canyon for the duration of the event. And with that, I have a few charts here. If we could go to the next slide.

This slide I have here, the blue line representing the send out or the demand on our system in the two billion cubic foot to two and a half billion cubic foot range, which is moderate for the winter season, where we can see send outs nearing four Bcf on colder days. So with that, we could go to the next slide, please.

And this is here to explain the -- what was going on the Southern System. So the blue line represents how much gas customers were confirming they wanted to bring on our system. And the orange line is what was actually getting scheduled. And normally those lines are close together, as seen before February 13th and after February 19th, where the lines are in alignment. However, during the event, you can see that blue line and the orange line, quite a large gap there where customers were trying to bring in gas, however, upstream limitations were preventing that gas from getting scheduled and brought into the SoCal system. So with that, we could go to the next slide where we could talk about our Summer 2021 Outlook.

SoCalGas evaluated a “Best and Worst Case” scenario. And in the best case, we found that we'll be able to meet peak day demands and fill the storage fields without the use of Aliso Canyon. I’m sorry, that peak day demand could be met without the use of Aliso Canyon. And in the worst case, we found that we could still meet the peak day demands, however, we’ll have insufficient receipt capacity to serve summer demand and fill the storage fields. So with that, we can go to the next slide, please.

And in the scenario evaluation, we consider planned maintenance activities on the system. And in the best case, we consider that the maintenance activities will go as planned and no changes to their schedule. And in the Worst Case, we consider potential delays for various reasons on that work, which would further limit supplies into our system.

To touch on maintenance this summer, we have a line 4,000 maintenance outage that started in May and is expected to last until October 1st. We had line 2001 maintenance activity, which was scheduled in May and went as planned. Lastly, indicated here, is the line 5,000 maintenance event, which is coming up in the coming weeks in July. So with that, I wanted to move to the next slide, please.

Okay, so our Peak Demand Forecast. So in the Best and Worst Case scenario, there's a difference between the Receipt Point Utilizations and in the Best Case scenario, we have more available receipts due to lesser maintenance impacts and potential supplies at the Otay Mesa Receipt Point. And so -- and also in the Best Case, we do not take into account that customers fully utilize all capacity on our -- on the receipt points. So we consider that 85% of that capacity is used by customers. In the worst case, we have less available receipt capacity, but we do consider a higher utilization of the receipt points due to tighter balancing requirements on customers. So we consider 90% in the Worst Case here.

In both cases, the scenarios ended up with 2.4 billion cubic feet of assumed pipeline supply. So very close together there. So the supply, pipeline supply, coupled with the available storage withdrawal we expect to have in these scenarios, allows us to expect to be able to meet the forecasted peak summer demand, which is just over 3.2 billion cubic feet on that peak day this summer. So in fact, you know, our total system capacity and our peak period this summer was found to be 3.89 billion cubic feet per day with the use of Aliso Canyon and 3.3 billion cubic feet per day without the use of Aliso Canyon. So with that, I'd like to go to the next slide, please.

So maintaining Summer energy reliability, first and foremost, SoCalGas is going to continue to coordinate with electric grid operators to facilitate reliability of our systems. We are going to continue to perform our compliance and safety related maintenance and try to do so in periods of low demands. Utilizing operational flow orders will happen to incentivize customers to balance their deliveries and use of gas. Consistent to the Aliso Canyon withdrawal protocol, withdrawals from Aliso Canyon may be utilized to maintain service to customers. And lastly, if we needed to maintain service to higher priority customers, we may need to issue curtailments. So with that, I'd like to go to the next slide, please.

You know, on the summer for reliability, we're seeing the need to utilize our storage fields in two ways this summer. Withdrawals from the storage fields will be needed to meet peak demand conditions when demand exceeds pipeline supplies. Also, when customer demand is lower than supply, we will continue to inject gas into the storage fields to increase or replenish our storage field inventories.

We wanted to note what's been observed as benefits of the 2019 updated Aliso Canyon Withdrawal Protocol. It's been recognized to reduce system stress and improve reliability. It assists in preserving inventory levels at the non Aliso Canyon fields. That helps reduce price spikes. That results from limited supply and high customer demands. And it can reduce the need for operational flow orders.

I wanted to touch on last year's peak summer dates on our system and how the storage fields were essential to meeting that high, really peak-hour demand. And if we could look at the next slide, please.

That -- so here's our look back from the peak days in August in the 2020 summer. What you can see here is the demand on our system or the send out, the blue line is quite variable. And the lowest point, you know, we're between 70 and 80 million cubic feet per hour in the early morning, late night hours. But in that peak evening time, you know, it's over 100 million cubic feet higher on a peak hour. And so those swings, demand on our system, how we're able to manage that is with the withdrawals from the storage field. So as you can see in the orangest area that's rather flat-lined across the chart there, that's our pipeline supplies that are rather consistent on an hourly basis. And to manage that peak demand, we're utilizing our storage fields on withdrawal to keep the system to maintain system integrity. So with that, I'd like to move to the next slide, please.

To touch on our current status in storage field inventories, you know, storage field withdrawal capability, it's important to meeting that demand and those peak hour demands. And the withdrawal capability it is directly corresponds to our field inventories. And the higher inventories we have, the more withdrawal we can -- we can pull out of the fields on those peak hours. So you know, Aliso Canyon’s at, this is as of yesterday, 31.6 billion cubic feet, Honor Rancho 24.9 billion cubic feet, La Goleta, 19.5 billion cubic feet, and Playa del Rey at 1.6 billion.

So overall, over 90% full in our storage fields as of yesterday. And you know, as the storage fields get full or they fill up, just wanted to point out that that injection capacity on our system will no longer be available. Our system capacity will be reduced, which can cause more high operational flow orders to be issued with tighter balancing tolerances on our system.

So with that, that concludes my presentation. And if there's any questions, I can answer now or later.

MS. RAITT: Great. Thank you, Brian. I think we're going to hold questions for the end. So thank you so much. And next, we have Kristina Abadjian, and she is a senior energy analyst at the CPUC, to present the CPUC Summer Assessment. Go ahead Kristina.

MS. ABADJIAN: Thank you, Heather, and thank you, Commissioners and Commission staff for hosting this critical workshop. Next slide, please.

So today I'll be going over the Supply Outlook Assumptions that were built into our Summer Reliability Assessment. And then I'll discuss the Gas Balance Scenario results. Compare those to actual outcomes we've observed as of June 30th. And lastly, I'll go over the Summer Peak Day Analysis that we incorporated into our assessment. Next slide, please.

So the Supply Outlook section includes two major components. First is the SoCalGas's -- the status of SoCalGas’s transmission pipeline network. The only major line that we assume to be out of service during the duration of the summer season was line 4,000. So we assumed that line 4,000 would be out of service for repairs from May 1st through September 30th, resulting in a reduction of 120 million cubic feet per day to SoCalGas’s Northern Zone. No other major pipelines were assumed to be out of service.

The second component is gas storage inventory levels. So we observed and included the gas storage inventory levels as of March 31st, 2021, which is the -- which is considered to be the end of the winter season in the gas world and right before the start of the summer season. So the combined inventory was approximately

62% full. And when comparing that to March 31st of the previous year, the inventory levels look nearly identical. We consider these to be fairly healthy inventory levels going into the summer season, especially when you compare these to the inventory levels of some recent years. I would say that this is largely a result of the current withdrawal protocol for Aliso Canyon, which was revised in the summer of 2019.

SoCalGas, under the current withdrawal protocol, has more flexible access to Aliso Canyon, in part to help balance the non-Aliso fields to ensure that they don't reach critically low inventory levels. Next slide, please.

So I guess Balance is a tool that enables us to observe margins between available capacity and customer demand. It doesn't include hourly variations you may see in a day, and it is based on average daily consumption, which means that in reality, you may have days with demand that's higher and days where demand is actually lower. Our Gas Balance Scenarios include two important limitations. The first are the low inventory shut-ins that are required under current Cal general rules. So under these rules, SoCalGas is required to take its four storage fields out of service for its low inventory shut-in. And this typically occurs during the spring injection season right around April or May, when a -- when a storage field is shut-in, it's completely taken offline, meaning you can't inject into the field, and you can't withdraw from it.

The second limitation we incorporated into our Gas Balance Assumptions are the storage injection rules that are required under the current SoCalGas triennial cost allocation processing. So under these rules, there is a certain amount of storage capacity allocated to core customers for injection and a certain amount of injection capacity allocated for load balancing purposes. So in our gas balances, we included two different demand scenarios which were based on the 2020 California Gas Report.

The first scenario was based, a hydro scenario, which assumes average hydro conditions, which means less dependence on gas fire generation. Under this scenario, the non Aliso fields became full in June and Aliso Canyon became full in July. Withdrawals were needed in August and September and as a result, all four storage fields were slightly drawn down by October. Our second Gas Balance Scenario was a cold year, dry hydro scenario, which I know sounds unusual, but the California Gas Report doesn't include a Hot Weather Dry Hydro Scenario. So this was our substitute scenario, which is important to include because under the scenario you have higher demand than under base hydro assumptions.

So in this scenario, the non Aliso fields became full in June, but Aliso Canyon did not reach its maximum allowable capacity, 34 Bcf, during any of the summer months. Withdrawals were needed in July, August, and September, and as a result all four storage fields were more significantly drawn down by October. Next slide, please.

So here we're going to compare the Gas Balance Predictions to actual Outcomes. So as mentioned in the previous slide, in both the base hydro and dry hydro cases, the non Aliso fields became full by the end of June, and we did not need withdrawals to meet customer demand in May or June. However, when we observed actual outcomes as of June 30th, the combined non Aliso fields were 90% full and Aliso Canyon was 87% full.

Actual injection patterns in May and June were actually fairly similar to the Gas Balance Injection Assumptions. However, the lower actual non Aliso inventory levels can be attributed to withdrawals that were needed in May and June. And as we know, June saw record breaking temperatures, which required withdrawals, mostly from the non Aliso fields. Next slide, please.

So the last bit that I'm going to go over here is the Summer Peak Day Analysis that we incorporated into the assessment. This was important because, as I mentioned, the gas balance doesn't capture peaks or hourly variations.

So we wanted to include a Summer Peak Day Analysis to see, you know, could we meet that data should it occur again? Again, the summer high demand day was -- it was an assumption from the California Gas Report. The high demand day was assumed to occur in September. And as you can see in the first table, line 4,000 was assumed to be out of service. And we assumed Aliso Canyon would be available for withdrawals under the current withdrawal protocol.

So as Column E shows in the first table, you are able to meet the summer peak day demand with a combination of pipeline receipts and withdrawal capacity. And you end up with a surplus of 755 million cubic feet. The second table, we -- the only difference here is that we assumed Aliso Canyon would not be available under the current withdrawal protocol. So again, as Column E shows, you have a surplus, you are able to meet the summer peak day demand with a combination of pipeline receipts and non Aliso withdrawals. However, you're left with much tighter margins. That concludes my presentation. And I will turn it over to you, Heather. Thank you.

MS. RAITT: Thank you so much, Kristina. And I'm sorry, I totally mispronounced your last name. Thank you.

MS. ABADJIAN: You're very welcome.

MS. RAITT: So next we have Joseph Long, and he's an energy economist for Energy Policy Market Assessment portion of Aspen Environmental. So go ahead, Joseph.

Mr. Long: Thank you, Heather. Good morning. And first, thank you to members of the dais and the attendees. I'm Joe Long, an energy economist at Aspen, and we provide technical support to the Energy Assessments Division at the CEC. Today, I'll be presenting a take at a Hot Summer Demand Scenario featuring SoCalGas. We also have the ability to do this same analysis for PG&E. But we started off with SoCalGas’s system and the data we used is public and comes from SoCalGas’s Envoy web portal.

So why are we doing this analysis? Normally when we consider the gas system, we would be talking about winter and winter heating demand, but there are a few reasons why we are now looking at the summer. Immediate concerns include the past August Heat Storm Event, which calls for attention to reliability. There is also a higher likelihood of extreme temperature events in the future due to climate change. And with the expected increase in heat events, there's also an implied increase in natural gas electric generation demand for air conditioning use. We also have some technical motives. To start, the Energy Commission doesn't have a model to forecast a Hot Summer Dry Hydro Demand scenario. And on the utility side, as Kristina mentioned, SoCalGas and PG&E do not produce a Hot Summer forecast for the CGR.

So the CEC and the CPUC wanted to think how we could construct a case for the summer without a temperature model. And we will present some of -- some of the ideas for doing so using the historical data as a substitute. Next slide, please.

So to set the scene for what a hot summer may look like, we looked back at the past August when we had blackouts due to heat storm over the weekend. This is the first thing that came to our mind when we considered what a hot summer could look like. The chart shows the event on each day in August of 2020 during the Heat event from the 14th to the 19th, gas demand ranged from 2,616 MMcfd to 3,249 MMcfd. The 261 on the slide should be 2,616 there for all of you following along at home. So as a benchmark, this exceeds SoCalGas's CGR Forecast of summer high send-out demand, which was forecasted to be 3,206 MMcfd in 2020.

One of the main concerns for the summer are multiday peaks and last summer realized a period of extended high send-out over the second half of August. We considered this as a potential case for our analysis to imagine last August demand for the entire summer to test the implied stress on the gas system. We considered this to be an extreme case and were surprised to see that when we looked back in the historical data, there were years that were much worse for demand. 2,000 in particular was very high demand year during the power crisis. Next slide, please.

So to get a broader picture of the past, we pulled system send-out for the last 22 years. On this graph, each line represents a year for 1999 to 2020 and shows average monthly demand for each summer months. Some of the takeaways are that August is the highest demand month out of the summer in 15 out of the last 22 years. We can see the trend in the red dotted line, which is the average of all the prior years. And there's an uptick in August. Anecdotally, the demand in August of 2000 was about 3,600 MMcfd on average. And we can see some decline in demand over the years with 2019 and 2020 at the top of this range in blue and to 2000 and 2000 -- Oh sorry, 2,000 and 2001 at the top of this range in blue and 2019 and 2020 at the bottom of the range in gray and gold. So I wanted to emphasize, as Kristina did as well, that these are monthly averages and daily demand will swing above these averages and the peak daily demands emphasizes this.

So the next question is whether it is right to use 22 years of data when the gas system has changed over time, and so we did some hypothesis testing to address that. Next slide, please.

We had a hypothesis that capacity and generation would have decreased over time and wanted to test this to see if it was reasonable to include 22 years of data. This graph looks more specifically at EG gas demand and shows EIA data for natural gas Generation and Generation Capacity. Capacity on the left axis and Generation on the right. In the last two decades, natural gas capacity grew over time, which is the orange line, and began to fall in the last six years. Overall, natural gas capacity remains higher today than it was in 1999. We can see Generation rise and falls over the period but is also still higher than 1999 and some of the larger Generation years can be linked to droughts and low hydro conditions. This tells us that gas Generation is higher today, even with decommissioning of plants alongside with the introduction of more renewables on the grid. So this leads us to the question of efficiency of Natural Gas Generation over time. So we looked at the Volume of the Natural Gas Burn as well. Next slide, please.

So for Gas Burn, there is a decline in demand over time, which can be seen in the last graph. We still see periods of higher demand resulting from low hydro years but overall gas demand for EG is declining as efficiency of Gas Burn increases since we are using less gas to generate more electricity. This supports the idea of doing the Analysis with the shorter historical period as the gas system, as the gas system has changed, with the important caveat that we're trying to come up with a Hot Summer scenario that covers prolonged heat events and continued high demand such as the year 2000. So if we exclude these higher demand years as outliers, then we would be under exaggerating a 1-in-35 or 1-in-10 standard that we are trying to replicate. So for that reason, this analysis was done with the full data set to include the extreme years. But we can, of course, explore different sensitivity cases as well. Next slide, please.

So back to the historical data. Here is a heat map of the average demand by month and year, another visualization of historical data we showed previously. The heat map emphasizes the fact that August is our hottest demand month, and that average demand is indeed declining as the lower half of this table gets less extreme as we get to 2020. Although demand is declining over time, including the earlier high demand years allows us to look at a scenario where demand could increase in the future due to electrification and higher natural gas demand for Generation. The heat map also shows again how bad 2000 was, as 2000 looks to be one of our 1-in-35 type cases for the summer. Next slide, please.

So we wanted to be sure that it wasn't just that August was the peak month on average but wanted to see if it was also the peak day for the summer as well. This graph shows the peak day for each year from 1999 to 2020. And it shows that the peak day for the summer occurred in August in 8 out of the last 22 summers and July and September tied for second place where the peak occurred seven times. Peak day demand ranges from about 3,000 MMcfd to about 4,000 MMcfd, historically. It also echoes the downward trend in demand over time as we see the peak day decreasing here. So that is all for background. We will get to the gas balance and our options. Next slide, please.

So we looked at four options for Hot Summer Demand scenario. The graph here shows them, along with some measures to base them off of. The gray shaded area is our historical range again. We also have the average of all historical data by month, which is the red dotted line again. And so the first case we consider is the black dotted line, which shows what would happen if we had last summer's average August demand occurring throughout the entire summer.

This is the August Blackout Demand Case, and it is constant. The second case is in blue, which is a composite of the highest average demand month out of the historical period, which just combines 2000 and 2001, which we call the Composite Case. A third case takes a probabilistic approach and looks at demand two standard deviations above the mean for each month. We call this the Sigma 2 Case, and the Sigma 2 Case says that 97.5% of all the demand days would be at or below this demand level. The Sigma 2 Case is also very close to the definition for the 1-in-35 standard. So that's a comparison. And for the last case, we created a 1-in-10 probability of occurrence from the historical data, which is in purple there.

We can also do sensitivity cases, like I mentioned before, looking at a 10-year record or just a single standard deviation. But the demand level really depends on what is considered safe for reliability. For comparison, the graph also shows the historical peak demand, which is the green dash line of top, which shows the highest daily demand in the record for each given month. This is to emphasize the point again that demand varies higher than the average monthly demand. The probability of occurrence of these days is next to zero as shown on the table on the right, but it shows they have occurred in the past, and we should still be worried about them for reliability. The goal now is to look at whether the gas system can maintain deliverability and whether storage can be built for winter under a given demand level, and we will use a Gas Balance and the Sigma 2 Case to demonstrate this. Next slide, please.

So we used the Gas Balance, which again allows us to look at deliverability and storage inventory levels over time. There's a lot to digest, so I'll try to go through it carefully. To start, line two shows demand out of -- out to March of 2022. Here we use the Sigma 2 values for the summer, which is May to October. And for April and November to March the rest of the year, we used SoCalGas's Monthly Average Temperature Forecast. Line three shows pipeline supply, which is assumed to be 2820 MMcfd and the difference in supply and demand results in injections and withdrawals from storage as shown in line 4. In the Sigma 2 Case, demand is larger than pipeline supply in the summer and results in withdrawals in May through October, in all the summer months. To be more specific, line 4 shows SoCalGas would have to withdraw from 77 MMcf a day on average in May, up to 739 MMcf a day in August.

On average, withdrawal capability is large enough to meet requirements for deliverability, assuming storage inventory is available. But on any given day, more withdrawals may be needed as daily demand varies above the monthly average. This tells us that there would be no ability to inject gas during this period and storage inventory would then decline. And as storage inventory declines, so does withdrawal capability. But the main concern for the gas balance here is looking at storage inventory for the winter. This brings us to the inventory line, which is line 5, which shows storage inventory drops below zero by the end of October and has no chance of meeting our winter storage inventory requirements under the Sigma 2 demand level. So assuming SoCalGas wants to meet those winter inventory requirements of 60 Bcf, for example, they would begin to curtail noncore load and if it is done on average over the summer, SoCalGas would have to curtail 370 MMcf every day of the summer, which is shown on line 6. We see on line 7 an injection and withdrawal after curtailment allows for injection in May and June and October. But SoCalGas would still have to withdraw gas in July, August, and September. Under this Curtailment scenario, SoCalGas would reach 60 Bcf of storage inventory by November 1st. This is, of course, an example SoCalGas would likely curtail differently in each month, depending on temperature forecasts and inventory, and they may end up curtailing more in May and June, for example, to prepare for heavier electric generation load in July, August and September. Next slide, please.

So the original question was to provide a proof of concept for potential summer demand scenarios and ways to evaluate them so we can use this process to test different demand levels or Sensitivity Analysis. But once there is a threshold for reliability, it can be tested. And of course, we can also do the same analysis for PG&E.

Other next steps would be to look at our view of SoCalGas's EG demand more specifically, rather than the statewide trends. We would also like to see CAISO and LADWP's recalculated Minimum Generation Values as we worry about electric reliability. But most importantly, we need to define the level of reliability and therefore the level of risk that we are willing to bear. The table shows this idea visually as the potential cost and implied curtailment values increase depending on the Reliability Case. So we are looking forward to continuing and expanding this analysis with your help.

And that is all I have for today. With that I will turn it back to Heather and thank you.

MS. RAITT: Great. Thank you so much, Joseph. So Commissioners if you have any questions for our speakers. And speakers, if you could go ahead and turn on your video again.

COMMISSIONER GUNDA: Yeah, first of all, I think just before jumping into questions, thank you for those extremely thorough presentations. That's an incredible amount of detail. And Melissa, thank you for your presentation, setting up the stage and the context of that. And Brian, for your assessment, and as well as Kristina and Joseph. Great presentations and helpful. Again, this continues the trend of sobering information of climate change and the impacts of that and the way we design our extreme scenarios and how do we plan to risk, the cost is different, elements. I think I have one high level question that I think one, for this year, for any of the -- any of the speakers. And two, a little bit more on the longer term, longer-term question. For this summer, looking at Joseph's presentation specifically on looking at an extremely, you know, hot summer, two Sigma, Sigma 2 situation, which then kind of results in a higher natural gas usage. But then you combine that with Kristina’s analysis on looking at some of the drought conditions as well. Right. I mean like you made the composite.

And first question is, is there real concern of curtailments this summer, from your vantage point? Especially to electric gen, and you know, the broader reliability that you know, has been the theme over the last two days. That's one question. And the second question is, as we build through the analysis to think through the Worst Case planning, how -- what are we thinking about potential winter peaking electric system and the impacts of the winter peaking electric system on the natural gas system reliability. So you know, any one of you want to take those two questions? I mean, I have a million questions to ask, but I'll stop there, and I'll pass it on to other Commissioners who might want to ask questions.

Maybe Kristina.

MS. ABADJIAN: Yeah. From my vantage point, I wouldn't say there is an immediate concern for potential electric generation curtailment this summer. However, I think the concern would be if you see multiple back to back hot weather days, right. As withdrawal capacity dwindles and the hot weather days just aren't ending, that's when you may have some potential concerns. But from an immediate vantage point, I would say the concerns are more so for the winter.

COMMISSIONER GUNDA: So anybody else want to add to that? Brian looks like you want to add.

MR. WALKER: Yeah. So in looking at Increased Electric Generation scenario, you know we get concerned about being able to have adequate storage inventories going into the winter. And if the win -- going into the winter you have lower storage inventories, you're going to tend to have to curtail noncore customers in the winter to maintain your minimum inventories through the winter to maintain core reliability. I mean that's kind of what we're thinking if that situation were to happen.

COMMISSIONER GUNDA: Joseph, I don't know if you wanted to add --

MR. JONES: Yeah, I was just going -- I was just going to add to the point of this summer. You know, we were kind of modeling an extreme case of, you know, high demand over the entire summer. And sort of as we look back at May and June, we can see we're obviously in a better state than we were there. And, you know, May and June were relatively mild for SoCalGas. But the question becomes, like Kristina said, the extended periods of heat like we've seen, you know, in the Pacific Northwest that could bring more attention to electric reliability. And then we also have this, the whole point of the summer concern is about, like we said, filling inject, or filling storage for winter. So the Summer Analysis still goes into our concerns for winter reliability.

COMMISSIONER GUNDA: Okay. Before I pass it on to another Commissioner, I recognize that you can't really compare the gas and the electric systems. I know it takes 21 days for us to get some molecules from Texas versus, you know, an instant on the electric side. But I just want to think through this broader planning of, you know, if we peak in the winter by moving forward on the electric side, how do you all think about the changing need for planning or any insights that you currently have? Just as a -- as a starting point for us to think through. Should I call on somebody? I don’t know if you’re all being polite, so maybe Brain, if you want to take it on.

MR. WALKER: Yeah. So changing to winter peaking in summer is kind of a compounding issue because that's already the heating peak demands. So it just goes to the importance of storage, in my opinion, in having adequate storage inventories and being able to fill it to support. Because you know, you run into scenarios like these polar vortex events that happen, and your pipeline supplies can be limited and you know, even more demand means it kind of even more kind of resiliency you need with the storage system being this part of the gas system at the end of the gas system, as it was pointed out by Melissa earlier.

COMMISSIONER GUNDA: Yeah, thank you. So Commissioners if anybody else want to ask a question it would be great to either, I think raise the hand would be good, but I'll start off with Commissioner Martha Guzman Aceves.

MS. GUZMAN ACEVES: Okay, thank you. I just had a couple of factual questions. I think I heard a slightly different thing from Melissa and Brian on the SoCal system. I thought maybe Melissa, you said that the SoCal system was more dependent on the Rocky Mountain Basin and the San Juan Basin, but then Brian, your presentation said you're more dependent on the -- on the Permian Basin.

MR. WALKER: I can take that. So the -- or I could start off. I'm sorry. You know we, the Rocky Mountains, San Juan, and Permian Basins are all supplies into our system. The Southern System at our Blythe area receipt point is primarily dependent on the Permian supplies as opposed to the other receipt points on our system. That was the most constrained during the event earlier in February.

COMMISSIONER GUZMAN ACEVES: Right. And is that, generally speaking, you know, a third of your dependency or is it 10% of your receipt points, usually? Your --

MR. WALKER: Approximately a third would be fair?

COMMISSIONER GUZMAN ACEVES: Mm-hmm. And when you said 47% of your RPU was, or your RPU was at 47%, was that system wide or was that the Southern?

MR. WALKER: System wide.

COMMISSIONER GUZMAN ACEVES: System wide. So the Permian Basin kind of freeze-off, if you will, that literally impacted your system wide receipt point to 47?

MR. WALKER: Yes. So I -- yes. That -- the event that day was 47% across our system.

COMMISSIONER GUZMAN ACEVES: Mm-hmm. And so typically, just I'm getting the math here, if it's a third, it would typically be -- I guess, how much -- is 47% representing something that is assuming you basically were not using any of that and a little bit the rest of the system was pretty normal. It's just that you stopped using any imports there.

MR. WALKER: So we had, I guess you could say, diminished or lower than expected supplies at Blythe, or Permian. And I think the other areas we saw lower deliveries, but the confirmation, the scheduled quantities there wasn't so much of a deficit. So it was specifically in the Blythe where there was upstream limitations directly impacting that utilization at that receipt point.

COMMISSIONER GUZMAN ACEVES: Okay. And then a separate factual question for Melissa. You talked about electric generation driving the demand of natural gas.

MS. JONES: Mm-hmm.

COMMISSIONER GUZMAN ACEVES: And certainly as we see this whole interplay here, all of our efforts of decarbonizing, given that statement and the percentage, and I did have a question on the percentage, 75% is from non-res. How much of that is from electric generation?

MS. JONES: If you look on that, well, I'll go back to the table and look. It is -- I just don't have the numbers right in front of me. Electric generation appears to be about half, historically about half, and then it increases a bit more, maybe 60%.

COMMISSIONER GUZMAN ACEVES: Okay. Yeah. Just this focus that we've, in terms of the timing of our strategies, it's an interesting thing to see the main driver being this electric generation and how our focus on, you know, let's say this shortfall that Joseph just pointed out of 350 million in the Basin. How much of that is equivalent to the electric generation that should become non gas and maybe that being more of the priority, given that it's the driver? Hey, that's not a question, but a reflection if anyone wants to build on that.

COMMISSIONER GUNDA: Thank you, Commissioner. Do you have any follow up question, Commissioner?

COMMISSIONER GUZMAN ACEVES: No. Thank you.

COMMISSIONER GUNDA: Okay. So with that, just looking for anybody else, want to have any questions? Yeah. Commissioner McAllister please and then Commissioner Monahan.

Commissioner McAllister, you’re muted.

COMMISSIONER MCALLISTER: The dreaded double mute. Apologies. So I really enjoyed the presentations. Thank you. They complimented each other extremely well. So all the knowledge just is very apparent across the board here. So thank you.

Just one quick -- one comment maybe to build on Commissioner Guzman Aceves just now. I guess, and if anybody has any insight on this. But you know, so yes, we have a lot going on the electric side and generation side, trying to wean off of fossil and you know, substitute in renewables of different flavors. On the -- on the core customer side also, you know we're looking at building decarbonization and that should, in theory, also free up some gas from that part of the sector. So interested in any comments about the timing of, you know, sort of the gas for direct-use versus gas for electricity generation and how those things, you know, can be managed over time and balanced. And so, you know, any sort of strategy that you all have been thinking about in that regard would be helpful to hear.

I guess my question, my specific question is for Brian. During the Vortex episode, you showed a graph that sort of had, you know, projections, versus deliveries, versus minimum flow requirements. And there were two or three points there where it looked like the actual deliveries approached were low enough that they approached the minimum flow requirements. And I guess I'm just wanting you to explain that a little bit more and give us a sense of what the implications of that are for core and noncore customers if those two lines were to actually cross.

MR. WALKER: Okay. Yeah, there were a couple points there where the -- we were getting close to the Southern System minimum with deliveries in the Southern System and the implication of that is, if we're not meeting the minimum, you know there's a system operator tool to purchase supplies in the Southern System to alleviate, to try to alleviate that. And then when you get into these conditions where there's no additional gas to procure in the Southern System then, you know that's a challenge. And that's why another reason, you know, we add that curtailment watch is to notify folks that, you know, if this gets worse or it continues, we could end up in curtailment. So you know, we would start with our seven-step process and the dispatchable electric generation would be curtailed first. And then lastly, ending at the core customers. So we didn't quite get there. We were concerned enough to put the curtailment watch out, but we were able to, you know, serve all the customers in that Southern System and not have to curtail anyone.

MS. JONES: So, this is Mellissa. Brian, we had talked to some of the people from SoCalGas who indicated that in the Southern System you have fewer noncore customers that you can curtail but, just because of the population. And so we had thought that that was a contributing factor as well in moving towards curtailment.

MR. WALKER: Yeah. I don't have the specific numbers to speak to you know how -- you know the percentage to other places, but you know, generally, a smaller population base of our -- of our overall customer. So likewise the noncore demand can, you can draw some parallels there. So yeah, it could quickly and not -- you could exceed the -- it could not be enough noncore demand to curtail quickly and enter the potentially core side. So on a rather sensitive area of our system.

COMMISSIONER MCALLISTER: Great. Thank you.

MS. JONES: And then there was one other point I wanted to make about storage withdrawals. It's not just for supplies, you know for reliability, with prices the way they were marketers and noncore customers who had storage were obviously going to withdrawal, and SoCal as well. You're going to withdraw your storage rather than buying out on the spot.

COMMISSIONER GUNDA: Thank you, Commissioner McAllister, and for those responses. So I just wanted to recognize, so we are looking over time, but I just asked Heather that we spend a few more minutes from questions from the dais. So Commissioner Monahan and Commissioner Rechtschaffen. So we're going to try to tease up in the next five minutes. Thank you.

COMMISSIONER MONAHAN: Great. Thank you. I have two quick, one is a quick question and one, maybe, is a little bit of a Pandora's box. But Brian, I'm curious, does the location of the storage matter in terms of being able to meet the systemwide demand?

MR. WALKER: So you know, being near the LA

Basin, the storage fields kind of, you know, support that, the area of high demand. One challenge with the storage fields is, you know, and is getting gas into our Southern System area. So that is a challenge that, you know storage gas, you know, does not necessarily get to the Southern System. And that's why we have that Southern System Minimum Flow Requirement for that area. Is that along the lines of answering your questions?

COMMISSIONER MONAHAN: Yeah. Well and the Pandora's Box question is just all of the analysis that shows Aliso Canyon remains a storage option, and I'm curious about analysis underway with, assuming that Aliso Canyon is not available for storage.

MS. JONES: So Commissioner Monahan, just to respond to that. This afternoon we're going to be having an extensive discussion about Aliso. And there are cases that have been --

COMMISSIONER MONAHAN: Ah.

MS. JONES: -- missing that.

COMMISSIONER MONAHAN: And I'm missing this afternoon. So I'm going to miss all the fun.

MS. JONES: Oh, that's too bad.

COMMISSIONER MONAHAN: Too bad for me. Too bad for me. All right. Thank you.

COMMISSIONER GUNDA: Commissioner Rechtschaffen.

COMMISSIONER RECHTSCHAFFEN: Yes. I don't have any questions, Commissioner Gunda.

COMMISISONER GUNDA: Thank you, Commissioner. I guess I didn't see you raising your hand or anything. So okay. It looks like -- looks like we are good. For the questions again, thank you so much for all the panelists for your time on this panel. I guess to Commissioner Guzman Aceves' question and then Commissioner Monahan's question at large, I think the analysis, you know, requires to evolve, to think through a lot of different conditions, especially on the electric side. I mean, we do have these decarbonization goals across all different sectors and kind of thinking through how they interplay and what that really means, being able to look holistically, show that to broader public, but also kind of, you know, members in the leadership would be really helpful. So I encourage you to continue to look at those things. And thank you so much. I'm going to pass it back to Heather.

MS. RAITT: Great. Thank you. So we have Jennifer Compagna is here to -- from the Energy Commission to moderate some questions that we received from the audience. So go ahead, Jennifer.

MS. CAMPAGNA: Okay, good morning. Can you hear me okay?

MS. RAITT: Yeah.

MS. COMPAGNA: Okay, great. The -- we have a few questions here. The first one I'll start off with is from Peter Scanlon. And this question is directed to Brian. It says, considerable effort has been made to address summer readiness on the electric grid, including managing electric generation outages to avoid shortages during peak demand summer periods or at least requiring replacement. Are efforts made to avoid events like the July Inspection Outage on Line 5000 during summer months, or at least providing long lead notice to customers that need the capacity to meet electric demand during heat events?

MR. WALKER: Alright. So the July inspection, that's upcoming. You know, we have compliance inspections that are, we have to do and it's one of those activities that we have to schedule when there's the lower demand to get the work done. So you know, we communicate with, you know [indiscernible] to, you know, address any concerns on an ongoing basis. And that's kind of -- that's kind of where we're at on it.

MS. CAMPAGNA: Okay. Thank you, Brian. I will move on to the next question. This is from Norm Peterson. Brian, this is for you again. And there's three parts. What will be the capacity of Line 4,000 when it returns to service on 10-1-2021? What will be the capacity of Line 235 after 10-1-2021? And what will be the capacity of the

Northern System after 10-1-21?

MR. WALKER: Yeah. That's all future capacity related questions that would be answered on our Envoy webpage when that information is available to the market.

MS. CAMPAGNA: Okay. Heather, do we have time for one more question or should we move on?

MS. RAITT: Sorry about that. Yeah. Go ahead and just do one last question, please.

MS. CAMPAGNA: Okay. Okay. Last question is from Denise Santacruz for either SoCalGas or Aspen. For summer the primary concern is EG demand during the 4-hour evening ramp. Increasing renewable energy integration will exacerbate this in the coming years. Solar goes away as people return home to hot buildings and natural gas fired generation is quickly ramped up to meet electric load demand. Can SoCalGas sustain those large hourly demand swings with or without storage?

MR. LONG: So for our analysis, we didn't really look at the hourly component of it, but I think it really gets to sort of what the Commissioners were saying about, you know, the balancing act in the sense that, okay, we're electrifying residential customers, but they still need this air conditioning demand. You know, what is that balancing act between, yes, we're increasing renewables, but we're decarbonizing maybe in a way where we're increasing the ramp. So how do we balance those things? And then I think it also goes back to the point where, yes, summer demand is lower and we have a winter peaking gas system, but we could have increased gas demand even on a daily basis just due to these, you know, extreme temperature events and higher air conditioning loads. So that's what I have for that. But less on the hourly stuff. So maybe Brian can help.

MR. WALKER: Yeah. So you know, I don't, you know without storage is definitely a challenge because pipeline supplies are consistent across the day. And as I tried to show in the chart, you know the hourly demand, it ramps up quite a bit, as indicated by the question here. So the way we manage that is by utilizing our storage fields and they're variable. We dispatch them to meet the demand to maintain the system integrity. You know, and likewise, the de-ramp can be a challenge too, where you may need to inject in storage fields to manage the de-ramp of the electric generators in the evening as well.

MS. RAITT: All right, thank you so much, Jennifer, and thank you so much to Melissa, and Brian, and Kristina, and Joseph for your presentations and for answering all those questions. We appreciate it.

And so if it’s okay, Commissioner, I think it's time to move on to our next segment. Okay.

So next, we'll move on to, we have presentations from CPUC and Energy Commission staff on the February 2021 polar vortex event. And so first, we'll hear from Anthony Dixon. He's the lead gas modeler at the Energy Commission. Go ahead, Anthony.

MR. DIXON: I hope everyone can hear me.

MS. RAITT: Yep.

MR. DIXON: Good. I had some computer issues and had to switch computers. So good morning, everyone. I am Anthony Dixon, the lead natural gas price modeler here at the Energy Commission. And I will be giving a brief overview of some of the impacts and things that happened during the Winter Storm Uri Event this last February. And can actually go to one more slide, please. Sorry. My notes are not coming up. All right.

So the extreme polar event lasted around February 13th through 17th, plus or minus a couple days. It was an emergency event, and it was greater magnitude than past polar vortex events that we have seen. This event extended all the way from Canada, all the way to the Gulf of Mexico, and saw numerous record cold temperatures throughout the middle of the United States. I mean, they saw snow in Galveston. This is probably one of the worst events we've seen, as far as this cold, in the last two decades. Next slide, please.

This had severe impacts on the natural gas and electricity reliability. And this was due to energy infrastructure shutdowns, disruptions, natural gas production losses, skyrocketing demand, we had rolling blackouts, load shedding, and there were natural gas and electricity price shocks that happened throughout this event. Next slide.

The shutdowns for the electricity and natural gas were due to multiple things. There were gas supply issues from well freeze-offs, the gathering in lines froze, valves froze, processing plants froze, power outages, which also reduce electricity, which is needed to run compressors and things to get gas onto the system. So you had a basically a compounding effect. It was even so cold that the wind turbines were freezing, and they weren't able to use your wind power. And of course, since it was a storm, we lost solar output. It was even so cold in Texas that there was a nuclear power plant they had to shut down because one of its water pumps froze. Next slide, please.

So how cold was it? This kind of shows some of the pricing hubs throughout North America and their average February temperatures, the coldest temperature that was seen during that week and their departure from the normal. The one, the Oklahoma, which is the "ONEOK", kind of in the middle, was forty four degrees below average for that time of year. Another important one is the El Paso Permian hub saw temperatures 40 degrees lower than what they normally would see. These are the temperatures that caused the water and these natural gas systems to freeze and led to so many issues. It was so cold in Texas that on February 14th, Texas averaged 15 degrees where Alaska was averaging 18 degrees. We saw a record of -10 degrees in Kansas City. Oklahoma City saw -14 degrees, the second lowest temperature on record there. Houston saw a low of 16 degrees and Dallas had a record low of 4 degrees. Next slide, please.

And this drastically impacted production. As you can see from this graph, the biggest one is that red line, which is the production out of Texas. The drop in production from Texas alone is greater than a lot of those other producing regions, combined production without these problems. Texas dropped so much that it was producing approximately 30% of what it normally produces during that time of the year. We saw production declines in Louisiana. We saw production declines in Oklahoma. Key notes is that we, and also the Permian Basin, that's in the New Mexico side. There was no loss of production in North and South Dakota as they are accustomed to cold temperatures kind of like Canada is. So their systems are winterized. And it's also to note that Kansas area did not see any production decline so obviously, and they had some very, very cold temperatures as well. So obviously, their system has been winterized. The San Juan basin in New Mexico did not see loss of production, and it wasn't because of necessary winterization, it's the temperatures there weren't cold enough to actually cause issues. Next slide, please.

So this loss of demand, or loss of supply, excuse me, plus a great spike in demand led to price spikes for the natural gas system. Several states and regions saw these spikes, including Southern California. And natural gas has the effect of kind of a double whammy when it comes to its price, as it's a direct impact as those who directly use the gas as heating and cooking. So these higher commodity prices are passed directly onto the consumers and then in the secondary, where natural gas is a major price effect on electricity prices. So a consumer now is paying a higher electricity in natural gas price on their bill because of these events. Next slide, please.

So to kind of show some of the prices across North America during -- on February 17th where some of the highest prices were seen. Prices were over $900 per MMBtu in Oklahoma. $150 in Iowa. We saw $100 plus per MMBtu in SoCalGas's service territory. This point, to notice that the Northeast in February did not see any price spikes from that. PG&E was relatively unscathed as they are able to get supplies from Canada and also can rely heavily on their storage systems to help alleviate some of these issues. SoCalGas did see some price spikes, but these are not any more elevated than we have seen since the Aliso Canyon and the Line 235 incidences. So those were within what normal -- what the new normal is for their system. Next slide, please.

So the potential effects on California and things we have to be concerned about. California is very susceptible to outside things happening. We are at the end of the interstate pipeline. We've seen these effects hit us from the February 21 incident that just happened, January 2014, February 2011, and even the heat waves that have been happening. We were fortunate that this time that was low demand here in California, as was mentioned earlier. PG&E was slightly over their average. PG&E norm for the last five years, have averaged about 2,900 million cubic feet per day of demand. Or excuse me, they averaged about 2,900 cubic -- million cubic feet of demand that week. Their average for February is around 2,600. SoCalGas was below average. They were around 2,200 million cubic feet averages during that week and for their February average is around 2,400.

Some withdrawals were -- like --- was mentioned by Melissa. Some of the withdrawals from storage were made for price reasons, not necessarily reliability, especially since utilities and the market participants really relied on storage to mitigate some of these effects. Next slide, please.

So winterization. This is basically protecting equipment from freezing. These can be simple things, well I wouldn't say simple, but this could be something like putting antifreeze in the system, kind of like we do in our cars to keep it from freezing. You can insulate equipment with blanket, with basically a thermal blanket that's designed. You can put equipment in buildings and keep them warm. NERC and FERC Report from the 2011 event showed it costs approximately $20,000 to $50,000 per well to permanently winterize them. Then the Federal Reserve Bank of Dallas estimated the losses in Texas alone from the winter storm Uri, this is Texas alone with $4.3 billion. So if an event like Uri happens once every 10 years, that's $430 million dollars a year, approximately, and that's more than what it would cost to winterize these systems. And this is only talking about Texas. This is not expanding out how much it costs all the way to here, to California, and the rest of the Midcontinent, and other areas. And there is concern that events like Uri could happen more often, which just from what we know, we've had three in the last 10 years. Next slide, please.

We studied New Mexico. They were particularly hard hit in the February 2011 polar vortex event. There, approximately 32,000 homes and businesses went without natural gas for several days. A state of emergency was issued. They had to open up numerous warming centers. At a point, they had to bring the National Guard out to help re-light the pilot lights. And this kind of furthers Melissa's point about relighting the pilots. A person has to go to every single house, they have to make sure everything's okay, and then relight the pilot light. And compounding that problem is someone has to be home to let them in. And if they have no gas or electricity, they could be at one of these warming centers or they could be with someone else's house. So it's very time consuming, very cost intensive. That's why Core is usually, they do everything to do to keep their lights on. Next slide, please.

So what did New Mexico do? Mexico -- the New Mexico utilities contracted for more natural gas and fuel oil and took other power options from the open market. The New Mexico Gas Company shifted away from the Permian Basin natural gas to San Juan when they realized this event was coming. San Juan did not see these extreme cold temperatures and did not see production losses. El Paso Electric contracted with fuel oil suppliers for their

Montana plant. And this is in Western El Paso County in Texas. So it's part of the WECC, not part of ERCOT. The public service company of New Mexico also took numerous other power options from the Western grid. And both New Mexico Gas Company and El Paso Electric improved and winterized their electric and natural gas infrastructure after the 2011 incident. They did things like expand pipeline sizes, expanded their electricity infrastructure, they winterized much of their equipment. Next slide, please.

So kind of in summary and some conclusions. After this event, Texas Governor Abbott signed Senate Bill 3, which is to winterize production wells in the state of Texas. However, the caveat about it is these are supposed to be wells that directly supply power plants. Unfortunately, there's no way to tell which well or which place is necessarily feeding directly to a power plant unless they have a direct connection from point A to point B, which they usually or most likely do not. Gas is kind of like electricity, it goes into a big pool, and you pull from it. So there's some kind of issues with this.

California is also, like I said, it's at the end of the natural gas line, so we're susceptible to these extreme events outside of California. We didn't see the cold weather here. It was there at -- in the Midwest and the Midcontinent and still affected us. And this can also happen in summer when as a heat wave hits those areas. You know, Texas is going to get the gas, then New Mexico, then Arizona. All these other places are going to pull gas off those El Paso lines and the trans western lines before they ever even get to us. These can lead to significant rate and price impacts. And we are very reliant on natural gas storage to mitigate these extreme events. And next slide.

And that concludes my presentation. And I will turn it back to you, Heather. Thank you.

MS. RAITT: Thank you so much, Anthony. Next we have Jean Spencer, and she is the project supervisor at the CPUC. So go ahead, Jean.

MS. SPENCER: Hi Heather. I don’t see my slides.

MS. RAITT: Let’s see. Here they come.

MS. SPENCER: Okay, thank you. All right. So my presentation is going to echo a lot of what you've heard today, but I'm going to be focusing specifically on the impacts of the polar vortex in California. Next slide.

So I'm going to be looking at the difference between the impact on PG&E versus SoCalGas, how impacts were different by customer class, how it impacted electricity prices, and then I'm going to focus in a little bit on SoCalGas because that's where a majority of the price spikes occurred. Next slide.

So the difference, this chart just shows the difference between the average spot market prices in the SoCal service territory versus the PG&E service territory. And as you can see, PG&E spiked, I think up to $11 and then went back down fairly quickly. SoCalGas got up to, and this is the average price, $140 MMBtu. And for comparison, normal is $3.00. So this is just an astronomical difference compared to normal prices. And they stayed quite high for several days and had a much more significant impact on the south. Next slide.

So why are these differences? I think Anthony already mentioned some of them. One is that PG&E is less exposed to Texas Gas. As you mentioned, they get a lot of gas from Canada, and they really leaned hard on that Western Canadian Sedimentary Basin. You can see on the map up at the top. So that was the second part. They're less exposed to Texas and they have access to Canada. They have more total storage because PG&E has its own storage fields but there's also the independent storage providers in Northern California, which have a lot of extra storage inventory. And storage is also available to noncore customers in Northern California. In Southern California, since the Aliso Canyon gas leak, there has not been sufficient storage for noncore customers to purchase new contracts. So they're really exposed to pipeline gas in the south in a way that they're not in the north. Next slide.

This is just to reiterate, this is the amount of gas flowing west from the Permian Basin, which was, as everyone mentioned, the hardest hit. Just, it just kind of fell off a cliff during this event. We did hear from, you know, some of the customers that there were some cuts to firm contracts from other Basins, but nothing on the scale of the Permian, which as was also mentioned previously, supplies the southern part of the SoCalGas system in normal times. Next slide.

So this is a visual of what was happening in each of the two service territories. And you can see in the PG&E service territory, the orange is storage, and the blue is Canada. And that's basically where all their gas was coming from. There's just really marginal amounts coming from the other areas. At some points during this event, PG&E was getting 70% of its gas -- of its gas demand and supply by gas from storage. In the SoCalGas service territory, there was a lot of gas coming out of storage as well, but they just don't have as much storage available. So they just couldn't pull as much out of storage. Some of the pipelines went down quite low, as you can see. And then a lot of the gas was coming in from El Paso and Kern/Mojave, which it, supplies are coming a little bit more to the north. Next slide.

So this -- So I put some numbers on that picture on the last slide. SoCalGas went through about 5.3 Bcfs during this period. Excuse me. PG&E withdrew about 5.7, but that's only part of the story because you have Wild Goose, Lodi, Gill Ranch, and Central Valley. And combined in northern California, 17.5 billion cubic feet of gas came out of storage to meet demand, compared to 5.3 in the -- in the north. So that just had a huge impact on flattening gas prices in the north. Next slide.

Okay. So the next thing I want to talk about is who is actually paying these stock market prices? And it wasn't everybody. It's important to understand that, you know, there's different ways to contract for gas. And if you have a firm contract, you get -- you pay the price that you agreed to when you signed the contract. So if I had signed a contract for all of winter and I was going to pay, let's say, $3.50 MMBtu for my gas, that's what I was paying during this event. I was not paying the spot market price. And if I have a firm contract, I'm first in line for whatever supply is available. So if there's cuts, I might get cut. But everybody, you know, anyone else is going to be cut before me and I'll probably have a pro-rata cut than a complete cut to my gas, unless things are just terribly dire. So if you have a firm contract, you're in a really different position during an event like this than if you have -- if you're out in the spot market. And core customers, which as was mentioned earlier, the residential and small business customers tend to have a lot of firm contracts. And the reason for that is the utilities buy their suppliers, and the CPUC regulates the utilities, and they -- we require them to hold at least 100% of their average daily winter demand in firm pipeline contracts. And we also require them to hold set amounts of inventory in storage at the beginning of winter. And that's to ensure that core reliability, which as everyone mentioned, is so critical because of the pilot light issue. So the thing about holding all this firm pipeline and storage contracts is that it's more expensive on the average day. But you know that Warren Buffett thing about when the tide goes out, you find out who's been swimming naked. Well core is not just wearing a bathing suit, they're like wearing a Victorian bathing costume.

So when there's a crisis, they are way more covered than your average customer. And I don't want to imply that they could never be hurt because they could if it was really high demand in California, they would be out in the spot market too, because if demand was super high, their firm contracts wouldn't cover it all. But in an event like this where there was moderate demand in

California, they had gas to spare and so they sold gas into the market. And that made a lot of money for ratepayers, actually. PG&E ratepayers getting $89.3 million back. SoCalGas ratepayers are getting $123 million dollars back because of some of the gas that was sold in February. Next slide.

So noncore customers are in a really different situation when it comes to their gas supply, and these include commercial industrial as well as electric generation. They purchase their own gas, and we have nothing to do with it. We don't regulate it. We're not allowed to regulate it. So they are making their own decisions about risk exposure. And we also don't have much insight, you know, they're making their own decisions, they're making their own purchases, we don't know whether they gained or lost or how they did. You know, that's a black box as far as we're concerned. And as I mentioned before, in Southern California, the noncore can't purchase new storage contracts. So they don't have that -- they don't have any way to hedge against events like the one we saw where the supply just wasn't available outside of the state.

Within the non-core customer class, different groups, I would guess, again I don't have firm date on this, were contracted differently. Industrial customers often have predictable loads. So if you have, if you know for example, say you're going to use one 100 million cubic feet every day, it would make a lot of sense for you to enter into a firm contract for that. So you know, you're getting your gas every day. But if you -- if you have really variable demand, it can be really, you know, a hard financial decision to enter into a firm contract, and that's what you see with the electric generators, especially those in the CAISO market, they don't know whether they're going to run or not until the day ahead. And so they don't want to enter into long term gas contracts, which means they're in the spot market. Like if I had to bet who is in the spot market during this event, would bet a lot of it was electric generators. And that has an impact on electric prices. Next slide.

So gas fired electric generators tend to be the marginal unit in the CAISO market. So they tend to set the price at which the, you know, the electricity clears and that's what happened here. So when there's prices in the gas market, I mean when prices spike in the gas market, they cause price spikes in the electric market, and they also tend to happen across the state. So NP15 is Northern California, SP15 is Southern California. The prices, the electricity spikes, prices spiked in both markets because it's more of a statewide electricity market. Even though the PG&E gas prices were low. Those Southern California gas prices were high and that impacted electricity markets across the state. We've seen that happen repeatedly. Fortunately, in this event, it was a relatively low electric demand period. So even though the prices were, they were higher than I've ever seen, far higher than I've ever seen, there wasn't that much demand that was paying those prices. So compared to like summer 2018, I don't think the impacts on electric, you know, overall electric vehicles will be as significant. Next slide.

Okay. So this has been covered a bit, so I'll just go over this quickly. But what we saw because of the, you know this kind of crash in production in Texas was the Receipt Point Utilization was way down. So that means the pipelines are flowing half full. If you look at the 16th, I think SoCalGas mentioned this already. My number is 1% higher. I had it at 48% full. The pipelines just were -- they were flowing more or less half full because they're just, the supply was just not available. Next slide.

And as I think this was mentioned previously, but I think it's helpful to have this in mind with looking at the next slide, there's two main reliability standards for the Southern California area. There's a 1-in-10 cold day and a 1-in-35. So the 1-in-10 day is the coldest day in 10 years. But it actually is a higher demand number than the 1-in-35 day because it assumes that all customers will be served. No one will be curtailed. And the forecasted number for 2021 was 4,967 million cubic feet a day. Or you could say 4.9 Bcf, or billion cubic feet. And the 1-in-35 day, because it's only core customers being served, is only 3,440. So it is actually lower. So that's important to keep in mind on the next slide.

So as this was happening, you know, I think about reliability every day and what was going through my mind was it's really mild weather here in California right now. What would be happening if we were having a high demand day here in California? And I think, I just want to point out here, that it's worth mentioning that I'm not sure that that would happen because, you know, the Rocky Mountains, I do, I think provide us some protection from these kind of polar vortex. I am by no means a climate expert, but I think that's something we should be looking at. Are we likely to ever have as cold a day in California as are having at Texas at the same time? I think that's a critical question.

But if we did, which was what my thought experiment was here, what would have happened during this event? So this first table, you know in the first column is just the dates of the event. The second column is the receipts that came onto the system, so that's the gas that's flowing in from the interstate pipelines. The third column is the available withdrawal capacity. So that's how much gas you could pull from storage on that particular day. And then the actual send-out. And as was mentioned previously, the send-out was super low, less than half of a peak day for most of these days. So in our actual event, there was a surplus for the day. However, in a 1-in-10 day, there would have been huge curtailments, as much as 2,037 on the 16th, which I just want to point out that's, even though no one's supposed to be curtailed on a 1-in-10 day, that would actually get down to the core level on that kind of day. That is a huge amount of curtailments. On a 1-in-35 day, again, just highly concerning that you would still be seeing core curtailments even with all the noncore customers curtailed. Next slide.

Okay. So then the second part of my thought experiment, and I think one of the Commissioners asked a question similar to this, is what if demand had been higher and Aliso Canyon was closed? So this table is you know, the first few columns are the same as the previous table. The only difference is the available withdrawal capacity is lowered to indicate the unavailability of Aliso Canyon. So what happens here is, again, just huge curtailments on a 1-in-10 day and actually even curtailments during the actual event that we had, which was a very low demand day. You can see on the 16th there's actually 35 million cubic feet of curtailments on that day. And the 1-in-35, again, just huge, curtailments. I mean this would be, you know, just a kind of catastrophe of pilot relighting afterwards. Next slide.

So again, I feel like I'm, you know I'm reiterating points that have been -- that have been made earlier, that California is at the end of the interstate pipelines and that poses supply risks that are beyond our control. We can't control what Texas does with its winterization. You know, we can't control what FERC does or, you know, things like that. That's just beyond what we can control. What is in the State's control to mitigate against these kind of supply risks, are access to diverse gas basins and storage. So I think, you know, even with SoCalGas the, as you saw, that because they had access to different Basins, they were able to keep the supply coming, even though it got really tight during this event. So with that, I --

COMMISSIONER GUNDA: Thank you. Thank you, Jean, for the presentation, and Anthony. Really helpful. I mean, I have a ton of questions, but I and I have the privilege of talking to both of you on a more regular basis. So I'll first pass on, the baton, to anybody else who might want to ask questions. Commissioner Rechtschaffen, please. You're muted, Commissioner.

COMMISSIONER RECHTSCHAFFEN: I have a question and a comment and maybe another question, but they're short. What -- if we were to translate the polar vortex into a Probabilistic Assessment of our cold winter days, what would we equate it to? Is it 1-in-35, 1-in-90. Do we have any sense, or Anthony, do you know what it was just in terms of the Texas Grid planning planners, do we have any sense of that at all?

MR. DIXON: Didn't look into the probabilistic of it, but I know just from looking at Jean's, she did the 1-in-10, which I'm guessing that was the, her equating that. So yeah. But we can look into it. I didn't -- did not look into seeing what it would have probabilistically --

COMMISSIONER RECHTSCHAFFEN: Yeah.

MR. DIXON: -- for their system and what they were checking into.

COMMISSIONER RECHTSCHAFFEN: Yeah.

MR. DIXON: But it's something we can definitely look into.

COMMISISONER RECHTSCHAFFEN: I understand. You know, 44 degrees below zero, it has to be a fairly extreme outlier for what we normally plan for. [indiscernible] question. I'll ask my question and then I'll make a comment. Do we know if FERC is likely to make any recommendations or, I don't know if they impose requirements on things like winterization of distribution facilities or otherwise. But Jean or Anthony, do we have any sense of what they might do in the aftermath of what happened this winter?

MS. SPENCER: So I have a very limited knowledge of FERC. I apologize. I did see some movement where they were kind of rumbling about doing something. I, and again I'm not a legal expert in this either, I do think there's a limited, you know the gas system is quite deregulated, especially the production, the gas production side of the system. So I, you know I, this is definitely not a legal opinion. I'm not sure how much they can do, but I do think they are increasingly interested in it as they see how much gas and electric reliability is intertwined.

COMMISSIONER RECHTSCHAFFEN: That comment I was going to make probably repeats the obvious, since I didn't say it, it has --maybe it should be said. In all seriousness, the combination of an outlier event or what seems to be an outlier event in this winter where it's 44 degrees below normal and then the heat storms and the heat storms we've had this summer where in the northwest or Canada, temperatures are 30 or 40 degrees above normal at climate threshold -- climate scientists are now thinking we may have crossed the threshold where the climate’s going to behave in unpredict -- very unpredictable ways and the heat storms like this may be the norm. And you have the similar event with what we've seen in wildfires, where last season the wildfire acreage doubled from the prior year when climate scientists thought that would take 30 or 40 or 50 years. All of this it scrambles how we think about reliability issues and theses standards, and Joseph's point of how much we have -- we, you know, what are we going to pay for reliability and what that even means in the context of these extreme and unpredictable events makes our challenges even greater. I don’t have any solutions, I'm just thinking aloud and reflecting upon some of the lessons that we're taking from these very extreme, unpredictable events.

MS. SPENCER: If I can just ---

COMMISSIONER GUNDA: Yeah. Thank you. Go ahead, Jean.

MS. SPENCER: -- respond to that. And I just want to say that's one of the challenges that we're seeing, is that on the gas side, we do expect gas, average gas demand to go down significantly. But it's really unclear whether peak demand is going to go down and if so, by how much. And that the peak demand is what drives the amount of infrastructure you need. So that's one of my concerns, is that if these peaks are really wild, then we might have to maintain a lot of infrastructure for reliability, which is, you know, obviously more expensive than maintaining less.

COMMISSIONER GUNDA: Thank you, Jean. Thank you, Commissioner Rechtschaffen. I know President Mainzer raised his hand, so thank you.

PRESIDENT MAINZER: Thank you Commissioner. Yes. I actually, Commissioner Rechtschaffen, I wanted to respond. It’s actually a really interesting line of questioning. I was just going to offer, you know I think that on the FERC Technical Conference on Western Resource Adequacy a couple of weeks ago. This was actually a really interesting question that Commissioner Glick raised. I think, you know, the Commission tends to, you know, have a pretty light footprint with respect to, you know certainly state level resource planning and, you know, things that are kind of in the jurisdiction of Public Utility Commissions, etcetera, in terms of, you know, specifics for individual research participants.

But they did ask a question, could they be helpful or what would be a mechanism to develop a greater sort of understanding of what’s, for example, loss of load probability means? Do you need to have some more standardized definitions of some of these resource adequacy metrics so that you could develop a better sense of you know, what does 1-in-10 mean? Once every 10 years? Once, you know days, months? What's the time definition? And then -- and then also, how do you start taking these uncertainty variables that you were talking about, in terms of weather volatility, load volatility, and packing that uncertainty into your assessment of what a reserve margin even looks like anymore? So that that was an interesting question.

And I'm not sure we necessarily want, you know, sort of some sort of FERC regulation on that,. But even at a subregional level, like we described yesterday, working with the power pool up north, working with the desert southwest entities, working with others to develop a little bit more of a common definition and then socializing the expectations around extreme events, seems like it would be useful because at the end of the day, cost considerations and those different tradeoffs come in. So I was just going to offer that perspective, and see if anybody has any reactions to that, if that's consistent with your thinking.

COMMISSIONER GUZMAN ACEVES: Well, I can actually respond partially to that. Not that it was pointed to me, but part of my question for these, Anthony and Jean, too, is you know this, certainly we have a narrow but regulation over some of the electric generators that are utility owned. But to your point, Elliott, is there, just as you've recently required some firm contracts for firm imports for the LSEs, is there also more we can be doing about what the electric generators have to do with their firm gas supplies to participate in the ISO as an example? Or, you know, certainly, can we be exploring what the utility owned electric generation must control, or even potentially with all the LSEs must have as part of their generation contracts?

It’s very clear that there's, as we've all said, the dependency on storage to both reliability and avoiding the tremendous cost impacts of when these gas prices peak is necessary, but also that there's not much being done from the electric generator community. And that's part of the question we have, and hopefully we'll explore further in this afternoon's panels. And they could even be looking at some of what Jean mentioned in terms of firm contracts, but also the use of storage for those noncore customers.

But I did want to also add, obviously, the other strategy. I know everyone's mentioned the utilization of storage as one of these immediate, obvious needs that we have. But the other obvious need that we have is, as we all sit here, and we talk about this volatility in our climate, and we know that the impact of methane to that volatility and this kind of perverse necessity to continue to rely on one of the leading causes of the heating of our climate. We know that the other strategy is obviously to invest in non-gas generation. To then, and local non gas generation, and we're obviously very limited in that. But that's the obvious other thing that we need to be acting on immediately. Something obviously that we talked more about yesterday.

So I just wanted to say that really wasn't a question that we need to act just as aggressively on these strategies to find that clean net peak generation that we need to have and particularly, the more of that that’s local, the better.

COMMISSIONER GUNDA: Yeah. Thank you. Thank you, Commissioner. It’s thoughtful words. So I think I, just in interest of time, I will bring it back to Heather, unless anyone from the dais has a pressing question. So I don't see anything. And I did think one way of like a comment that I think -- oh. Commissioner Monahan. Yes.

COMMISSIONER MONAHAN: Yeah. I don't really have a, it's not a question, but just a really quick comment. And I'm not going to be here for the afternoon, but I want to just build on what Commissioner Rechtschaffen was saying, and Elliott as well, in terms of this sense we have that, you know, our old metrics and ways of evaluating risks are in flux. And 1-in-10 no longer seems necessarily like the right metric because we're seeing an increase in these polar vortex, high heat events across the country. And so it -- we're just in this, I think period of real dilemma about well, how do you make sure that we have sufficient resources to account for when these extreme events occur and they're occurring on a more frequent basis because of climate change.

And as Commissioner Guzman Aceves said, we have to move to lower carbon energy sources that are resilient and build resilience into our greater storage, and reliance on strategies to address, you know, when we are having high heat events, how do we make sure that we have enough resources for critical needs to prepare for them? And so just this growing sense, I think, that we're all struggling with about how do we make sure that we're doing all we can to protect Californians and make sure we have a resilient, affordable energy system while also making sure that we're accounting for some of these high heat, high cold polar vortex event. So just a comment more than anything else.

COMMISSIONER GUNDA: So thank you, Commissioner Monahan. I think you put it really well. And I think Commissioner Martha Guzman Aceves kind of mentioned this morning about the equity of this entire transition. I think from my kind of vantage point, just as a closing thought on this really is, you know, we have a pretty robust planning process now on the electricity side, obviously. Even though we have a robust planning process, it's still I know we're going through this incredible flux that requires, you know, additional. And I think this is this is really an opportunity for us to think through, you know, the robust planning kind of a framework for the gas side. And I know -- I know Jean is involved in this, and Commissioner Rechtschaffen of the, you know the CPUC has the proceeding coming on the Phase 3 I believe, or the Phase 2 on the Natural Gas Transition.

So I think, you know, we are in an incredible transitional period and then everything that's hitting us, you know, this last year and then now we are observing. So I'm just, I’m grateful for the staff, for their continued work. And I really would like us to really think through how broadly we can conserve our scenarios so we can really think through a path that's reliable, safe, and equitable for State of California. So hopefully we'll get there. So with that, I'll pass it to Heather.

MS. RAITT: Thank you, Commissioner. So I think we have time for one question from attendees. So Jennifer Campagna, if you can so the companies could go ahead and read out the question. Thank you.

MS. CAMPAGNA: Yes. A question from Jack Cheng.

Is there a reason why this SoCalGas deficit was lower for the 1-in-35 day than for a 1-in-10 day? It seems like it should be higher for the 1-in-35 day.

MS. SPENCER: Yeah. That's why I presented the standards before I got into that. So the 1-in-35 Forecast is actually lower because it assumes that all the noncore customers are curtailed. So hospitals, electric generators, refineries, everybody is curtailed. The only people who are still getting their gas are the residential and small business customers. That's why it's lower.

MS. CAMPAGNA: Okay, thank you.

COMMISSIONER GUNDA: If, I mean, I think I see only one other questions. Heather, do you think it's okay for us to get to that one question too?

MS. RAITT: Sure. Go ahead.

MS. CAMPAGNA: Okay. Question from Norm Peterson and this is for Jean. Brian Walker said, SoCalGas's Receipt Point Utilization dropped as low as 47% during the polar vortex event. Has the Energy Division been able to determine how much of that decline in RPU was because the Gas Acquisition Department decided to sell into the market, taking market away from border flowing supplies and making the $123 million for the core and shareholders through the gas cost incentive mechanism? Let me know if you need me to repeat any part of that.

MS. SPENCER: I think I've got that. I don't know if we looked at that specifically, but I mean, I think it's really we, a lot of what we know I can't discuss publicly. So what can I say here? I would say that gas acquisition is required to meet the needs of its customers. And it did that. So we could perhaps delve into more detail. We have delved into some detail, but I think that's about the extent of what I can say.

COMMISSIONER GUZMAN ACEVES: Jean, can I ask a follow up on that? I don't know if it's -- so we were withdrawing at this, during these days, obviously, to keep everyone served. But the fact that we were selling as well. Is that a practice -- should we have allowed the gas company to sell gas that otherwise could have been kept in inventory?

MS. SPENCER: So let's see. So the core, I mean the gas acquisition is supposed to get the best deal possible for core customers. That's its role. And the one thing, you know and again, back to Norm’s question a little bit. A lot of times it wouldn't necessarily mean that gas is going out of California through the pipelines. It might just be that gas is sold before it gets to California. So that would be my guess as to what happened as far as, you know, gas that was sold elsewhere.

As far as keeping it in storage, I think, I mean this would just be my take, is if we were looking at a situation similar to, and I'm trying to remember what year it was. Was it ‘18, ‘19 when gas stored supplies were critically, dangerously low? If I saw gas acquisition selling gas out of storage in that circumstances, I would be very, very concerned because the storage was low. It was very dangerously low. However, that wasn't the case this year. And I would say again that I think there was a lot of effort to supply the Southern System from the north that was helpful to the entire area.

So I guess the way the way it's set up now, gas markets are really deregulated and that's the rules of the game as they are set up right now. I don't, I guess I think that's open to question how people feel about that. You do see these huge gas prices, and I think gas spikes got up to $1,250 in Oklahoma, but that is a way of allocating scarce resources in a time of great crisis when people's lives are on the line. Whether that's the correct way, I would venture.

MS. RAITT: Okay. Commissioner Gunda, I think we should probably move on to public comment.

COMMISSIONER GUNDA: Absolutely, Heather.

MS. RAITT: Thank you, Jean and thank you, Anthony. Very much appreciate that. So RoseMary Avalos from the Public Adviser's Office is here to manage public comment, so go ahead RoseMary.

MS. AVALOS: Thank you, Heather. Commenters, please allow one person per organization to make a comment. And comments are limited to three minutes per person. I’ll first call on the folks using the hand raise on Zoom. We have Norman Peterson. Your line is open. Please state your name, your first and last name, and spell your first and last name and let us know if you have an affiliation. So go ahead and speak. You may need to unmute on your end.

MR. PETERSON: Yes. My name is Norm Peterson, but I actually did not have a comment. I asked my questions through the question feature.

MS. AVALOS: All right. Well thank you. So we'll move on to the phone line and we have 497. Go ahead and open your line by hitting *9. All right. Please take your first and last name and spell your first and last name and any affiliation as well. Go ahead.

MR. PETERSON: Good afternoon. This is Todd Peterson, T-O-D-D, P-E-T-E-R-S-O-N. I’m a principle with Pacific Gas and Electric Company and Energy Procurement and Policy. So PG&E appreciate the opportunity to provide comments on the Integrated Energy Policy Report, the Joint Agency workshop today. Something PG&E would like to do is to encourage the California Energy Commission, the California Public Utilities Commission, and the California

Gas Utilities to work collectively to look more closely at the projected summer and winter peak conditions, particularly as electric vehicle use and building electrification policies grow.

PG&E also recognizes the need for more granular gas demand projections than just the annual average gas projections that we've see, to better understand a few key elements, particularly infrastructure needs. We do see growth in electric vehicles and growth in municipal building electrification policies. And then, as we talked about earlier today, particularly the relative daily and seasonal gas demand variability and particularly as California finds more intermittent gas generation capacity vary, are hydro conditions and also electric vehicle and building electrification policies.

Another point to look at here is to acknowledge the importance of the relative Northern and Southern California gas prices that certainly impact the economic dispatch of electric generation, and particularly in the CAISO marketplace. And that this can cause electric generation gas throughput to change significantly in one region or one service territory versus another, on these relative gas prices. I have -- PG&E will strive to provide written comments by July 23rd to elaborate more on these verbal comments.

Thank you for the opportunity.

MS. AVALOS: All right. Thank you. And seeing there are no other raised hands, this completes public comment. I now turn to Commissioner Gunda.

COMMISSIONER GUNDA: Yeah. Thank you RoseMary. Thank you again to all the panelists and all the attendees for the questions and the comments, as well as the time that the panelists gave us today and sharing their thoughts in their subject matter expertise, but also answering the questions. I think it really important, incredibly important conversation. And I'm glad that we are having this today. And I hope most of you are able to join for the afternoon session, which will be led by Commissioner Martha Guzman Aceves, specifically looking at Aliso Canyon and the reliability issues there.

So I'm guessing we'll be back at 2 o'clock as per plan. But before I hand it over to Heather, maybe just ask Commissioner McAllister if he has any comments and then pass it back to Heather.

COMMISSIONER MCALLISTER: Great. Thank you, Commissioner Gunda. Yeah. Just looking forward to having everyone back here in the afternoon. Thanks to all the presenters. That was incredibly substantive. A lot of good, solid baseline information for us to utilize in deliberations going forward throughout the IEPR cycle and beyond. Really helpful level setting. And again, I think building on what we talked about yesterday on the electric side, you know, sobering in terms of just identifying the challenges and the potential challenges that you have some likelihood of occurring and creating, you know, really near term stresses for the gas and electric side. So really appreciate that. Looking forward to this afternoon. Thank you, Commissioner Guzman Aceves for initiating and leading that.

And so with that, I think we're adjourned for the morning, and we'll see you at 2:00.

(The Joint Agency Workshop Adjourned at 12:31 p.m.)

CERTIFICATE OF REPORTER

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 8th day of October, 2021.

Martha L. Nelson

MARTHA L. NELSON, CERT**367

CERTIFICATE OF TRANSCRIBER

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

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

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

Martha L. Nelson

MARTHA L. NELSON, CERT**367

October 8, 2021