UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference
to Discuss Climate Change,
Extreme Weather, & Electric
System Reliability   Docket No: AD21-13-000

TECHNICAL VIDEO CONFERENCE

Federal Energy Regulatory Commission

888 1st Street NE

Washington, DC 20426

Wednesday, June 2, 2021

1:00 p.m.

Opening Remarks

Panel 3: Operating Practices for Addressing Climate Change and Extreme Weather

David Patton, President, Potomac Economics

Amanda Frazier, Senior Vice President of Regulatory Policy, Vistra Corp

Robin Broder Hytowitz, Senior Engineer, Electric Power Research Institute.

Renuka Chatterjee, Executive Director of Systems Operations, Midcontinent ISO

Wesley Yeomans, Vice President of Operations, New York ISO

Anne Hoskins, Chief Policy Officer, Sunrun, Inc.

Mads Ronne Almassalkhi, Assistant Professor at the University of Vermont, and Chief Scientist at PNNL and Co-founder of Packetized Energy.

Panel 4: Recovery and Restoration

Kevin Geraghty, Senior Vice President of Electric Operations, San Diego Gas and Electric

Daniel Brooks, Vice President Integrated Grid and Energy Systems

Charles Long, Vice President of Transmission Planning and Strategy, Entergy

Michael Bryson, Senior Vice President of Operations, PJM Interconnection

Brian Slocum, Vice President of Operations, ITC Holding
Jodi Moskowitz, Deputy General Counsel and RTO Strategy Officer at PSEG.
Panel 5: Coordination
Karen Wayland, Chief Executive Officer, GridWise Alliance
Randy Howard, General Manager, Northern California Power Agency
Dan Scripps, Chairman, Michigan Public Service commission
Letha Tawney, Commissioner, Oregon Public Utilities Commission
Carolyn Barbash, Vice President of Transmission and Development Policy, NV Energy
Patricia A. Hoffman, Acting Assistant Secretary, Principal Deputy Assistant Secretary, Office of Electricity, U.S. Department of Energy

P R O C E E D I N G S

Opening Remarks

MR. AMERKHAIL: Good afternoon everyone and welcome back to the Federal Energy Regulatory Commission's Technical Conference on Climate Change and Extreme Weather and Electric System Reliability. My name is Rahim Amerkhail and I'm with the Commission's Office of Energy Policy and Innovation.

The purpose of this conference is to discuss issues surrounding the threat to electric system reliability posed by climate change and extreme weather events. We do not intend to discuss the specific details of any current or contested proceedings before the Commission whether listed on the supplemental notice issued on May 27th or not.

And we'd ask that all participants similar refrain from such discretion. If anyone engages in these kinds of discussions my colleague, Michael Haddad from the Office of General Counsel will interrupt the discussion to ask the speaker to avoid that topic.

For those of you tuning in for the first time today, I want to cover some logistics for the conference. We will have three panels this afternoon. We will also a break in between panels. Only the Commissioners, panelists and small group of Commission staff will have the ability to speak today.

This conference is being webcast and transcribed. With those reminders out of the way let's get started with the third panel entitled, "Operating Practices for Addressing Climate Change and Extreme Weather." I'll turn it over to our moderators thank you.

Panel 3: Operating Practices for Addressing Climate Change and Extreme Weather

MR. WHITMAN: Thank you. I'm Peter Whitman from the Office of Energy Policy and Innovation, and along with my colleague Elizabeth Topping, also from the Policy Office, I'll be serving as moderator.

This panel will explore the ways in which existing operating practices, including but not limited to those pertaining to seasonal assessments, outage planning, and coordination, reserve procurement and the insight management unit commitment of dispatch, short-term asset management and emergency operating procedures and they necessitate updated techniques and approaches in light of increasing instances of extreme weather and longer term threats posed by climate change.

We will be foregoing opening remarks for this panel and will move directly into a question and answer session. Following this panel we will have a 20 minute break. I'd like to start by introducing our panel three panelists.

We have David Patton, President of Potomac Economics; Amanda Frazier, Senior Vice President of Regulatory Policy at Vistra Corporation; Robin Broder Hytowitz, Senior Engineer, Electric Power Research Institute; Renuka Chatterjee, Executive Director and Systems Operations, Midcontinent ISO; Wesley Yeomans, Vice President of Operations, New York ISO; Anne Hoskins, Chief Policy Officer, Sunrun, Inc. and Mads Ronne Almassalkhi, Assistant Professor at the University of Vermont, and Chief Scientist at PNNL and Co-founder of Packetized Energy.

Thank you. Welcome panelists. As we begin I'd like to remind all participants to refrain from any discussion on any contested proceedings. If anyone engages in these kinds of discussions my colleague Michael Haddad from the Office of General Counsel will interrupt the discussion to ask the speaker to avoid that topic.

We will now begin with a question and answer session. If a panelist would like to answer a question please use the Webex raise hand function. Alternatively, if you are having issues with raise hand please turn on your microphone and indicate that you would like to respond. We will call on panelists that indicate they would like to answer in turn.

Once we do so, please turn on your microphone and respond to the question. When you have completed your answer, please turn off your microphone and also lower your virtual hand so we don't think that you have a follow-up. With that I'll turn it over my colleague Elizabeth Topping.

MS. TOPPING: Thank you Peter. Good afternoon everyone. For our first question we'd like to start with a broad one and that is how can market structures or rules be reformed to give generators and other resources stronger incentive to be prepared for the challenge of climate change or extreme weather that they may face?

Can new market products, for example, seasonal products, or enhancements to existing market structures be designed based on defined reliability for resilience needs in order to address the challenges of climate change and extreme weather?

Okay let's see. Please raise your hand if you would like to answer and let's go to Amanda first.

MS. FRAZIER: Thank you very much Elizabeth and Pete, and thank you for allowing me to participate on the panel this afternoon. I'm appreciative also to FERC Commissioners for hosting this technical conference. I think it's an important discussion. You know I think the low-hanging fruit on how do you incorporate into the market, ways to address both climate change and reliability is to incorporate carbon pricing into the market.

There are a number of different ways to do that, and the Commission recently finalized a policy statement on carbon pricing in the market which Vistra fully supports. And then once you have carbon as an optimization tool inside the markets, then you will be able to attract the right collection of resources, both to address decarbonization goals along with reliability needs.

I think other ideas that you know some RTOs and ISOs have considered, and for example ISO New England has implemented they're called inventory energy programs. You know I think that's an interesting way to ensure that you are attracting fuel secure resources for winter seasons in particular, or for seasons where you expect to need additional incentives to make sure that you have fuel security for resources to perform as needed.

I know that you know ISO New England also had considered and submitted a proposal called Energy Security Initiative, and I think that's something that will continue to evolve in the northeast as well. But those types of programs I think are an interesting way, and a good way, and a market-based way to address getting the right resources in for events such as winter, winter events.

MR. WHITMAN: Thank you. Next we'll go on to Wes.

MR. YEOMANS: Good afternoon, and again thanks for inviting the New York ISO to this panel. The majority of our extreme weather concerns at this point in time, at least the last five or 10 years have been extreme cold weather. We certainly can have heatwaves in New York City, and we expect to have more of those.

We experienced the severe Hurricane Sandy which hit New York City and Long Island, New Jersey and Connecticut back in the late 2012, ice storm in the late 90's, but for this question from a market structure and rules perspective, I'll really be talking about things that we've done to better prepare for the very cold weather operation with limited pipeline capability.

If we had unlimited pipeline capability I don't believe we'd have a problem with extreme cold weather but that's not the case. One of the first things we've done recently really since the polar vortex of January 2014 is as everyone knows single cost recovery certainly is a large aspect of ensuring reliability.

We've enhanced the capability to allow generators to provide expected costs for day ahead market reference level developments and enhanced our consultation process such that generators can get cost recovery for their legitimate tool cost to assist with reliability during cold weather operations, and all situations, and all other types of tight operating conditions where we have substantial reliability issues.

Moving on to reserves. Up until the polar vortex we just happened -- the result of our market with a lot of latent, excess reserves, but really starting at about the time of the polar vortex and even continuing since then so many resources had switched the gas, the fuel of choice because it's inexpensive natural gas, and again the limited pipeline supply that we thought it prudent to increase the amount of operating reserves that we schedule and purchase and pay for in both the day ahead and the real time. And by increase, I mean above the minimum operating requirement.

So we had a long time period where we had a smaller large contingent with an energy redispatch where markets on our borders could only use rescheduled energy, and recreate the operating reserves, but starting about 2014 that became more challenging, so we did the right thing and just increased the quantity, and we scheduled it and we paid for it and that works well.

Since January '14, I think around 2015 we modified reserve shortage pricing, which modified means increased the pricing for reserve shortages with our closed, and that better values the reliability benefits of operating reserves, hence the same generator to secure more fuel in week ahead schedules.

In the world of regulation service we've proactively done studies, maybe not so much for climate change and extreme weather, but really to prepare for more renewables, whether it's more wind or more solar. We've done studies ahead of time to say at certain high levels of renewables what additional regulation will we need, and we put some of those higher numbers in place in our market systems.

Moving forward I won't list all the things that we have going on, but we've written a significant white paper on what we need to do to incorporate large volumes of solar and wind over the next five to 10 years. We have a white paper. I won't list all that. That's not necessarily written for extreme weather, but those market enhancements and reliability rule enhancements that we need for very large volumes of wind and solar are consistent for the types of product we're going to need for extreme weather and climate change.

And then from a reliability rules perspective different than market enhancements, we have improved our weekly dual monitoring capability, testing every six months to make sure the dual field units can start annual generator visits to make sure they're ready for hot and cold weather operations and extreme weather, improved our communications with the gas industry, emergency procedure for the gas industry, and we've always even before polar vortex at our oil burn rules that require a certain number of generators to have dual fuel capability.

We had to switch to oil at certain high load thresholds such that we had the resiliency in the event of a pipeline break. So again, that's my response.

MR. WHITMAN: Fantastic thank you. David you're next.

MR. PATTON: Hi. Thanks to the Commission for the invitation to speak at this Conference. I think this is a really interesting set of topics, and I think we monitor New York and New England and MISO and ERCOT, all of which have very different market structures and rules that put them in either a better position or a worse position to address these sort of extreme conditions.

So most of my comments won't be specific about a particular RTO. Some of them might be, but really talking about more generally how the markets in all these areas are prepared to address these more extreme events. First and foremost I would say 90-95 percent of the objectives should be to get shortage pricing correct in all of the RTOs.

Shortage pricing is incredibly important because it not only allows you, allows the RTOs to price and send efficient incentives for things you might foresee coming with some degree of probability, but also maybe even more importantly it helps you price and send incentives to deal with situations that are highly unlikely that you don't see coming, and extreme weather events definitely fall into that category.

They're not events that would make sense to plan for. In other words to have planning criteria to address because they are so specific and many of them are so low probability that that would be enormously costly to have mandates to try to address them. But the incentives provided by shortage pricing will provide correct incentives for and people respond to naturally who own assets, or who serve load.

And by way of comparison I would say New England has by far the strongest shortage pricing. It's embedded in their pay for performance, but people often don't understand that that's really just shortage pricing that is packaged and settled outside the energy market. There are some downsides of doing that, but nonetheless it is by far the strongest in the country.

ERCOT perhaps is next, and I would say New York and MISO are kind of woefully inadequate, so bringing them up to a standard that would reflect the value of the loss load that you might experience during these extreme events will help provide much better incentives in those two markets to prepare for extreme events. So that's where I would start.

I don't think seasonal products or other types of products are very helpful because you have to get the spot price that tell you at every moment what energy is worth correct? And then you can have seasonal products that settle against that spot price, but having a seasonable product by itself I think is not very helpful.

MR. WHITMAN: Interesting, thank you. Renuka?

MS. CHATTERJEE: Thank you and good afternoon. Thank you to the Commission to having MISO at this technical conference. I would like to start by saying that the outcome of many years of preparation and planning as you approach the extreme event, they are the weather.

As many have suggested prior to me the generation performance is critical, not just during extreme weather events. It's critical at all times. If the generation doesn't show up at the required commitment, that obligation at the required time, we quickly get into actions that are less talked about in terms of using operating reserves, reserves that will be needed to maintain supply and demand values.

Specifically with regards to market structures, forward looking actions to improve generation performance, MISO certainly thinks that winterization is a critical element. MISO's footprint we have you know extreme cold in the north, and extreme heat in the south, so we do face both those extreme situations. Specifically for extreme weather events, again we could put in mechanisms such as scarcity pricing that we talked about, or seasonal constructs amortization, but when you get into the actual event we must recognize that you have what you have and try to maintain the liability at that point.

So it's good to have multiple options. So as I reflect upon the February arctic event, it's not that we didn't have enough generation. We couldn't get it to where it needed to go. So again we can think about having locally sufficient generation, but at the same time you need transmission.

All of this is a market for the compounder that the more uncertainty that's coming forward, so the MISO is looking to implement products like the shut-down reserves that should give us uncertainty management tools, including seasonal and pricing mechanisms that will improve availability, but at the end of the day when you are talking specifically about extreme weather events, we have to look at multiple options.

The biggest lesson learned for us from the arctic weather event was that MISO is well situated and right in the middle of the country along with its neighbors that allowed us to import power. Again you want to first be self-sufficient if it's within your FERC -- if it isn't you want to look instead of the footprint, not outside the footprint to import energy.

So it's about having multiple options given the extreme weather events. The risks generally compound during extreme weather events and what you don't anticipate will happen during extreme weather events.

MR. WHITMAN: Thank you. Next is Robin. I note that EPRI has done a lot of work in sketching out the problem for this.

MS. HYTOWITZ: Thank you very much Pete, and thank you for welcoming EPRI to this panel and it's an honor to be able to speak with my fellow panelists here on this topic. So as you mentioned EPRI has done quite a bit of work on this topic, but first I wanted to just kind of think more generally about incentives right.

When we think about incentives, we also think about prices. And some of the work we've done and just giving a high level look at what are prices -- energy prices during these events. And so we took a look at four different events. Super storm Sandy and Hurricane Harvey as two major storms, and the average LMP for NYISO during super storm Sandy was around $32.00 a megawatt hour.

And Hurricane Harvey the average price was for two different zones was $23.00 and $37.00 a megawatt hour. And then we contrast that with polar vortex in winter storm events. And so during the 2014 polar vortex NYISO prices were $180.00 a megawatt hour approximately, and then of course we know this past February with Winter Storm Uri prices were extraordinary high in ERCOT, over $6,500.00 a megawatt hour.

And so contrasting these two types of events we see very different outcomes right? So this queue, the polar vortex, the cold winter events have high prices right? We saw a shortage of supply in those cases. Whereas the two, the super storm and the Hurricane Harvey we saw T and D outages and so often times our demand is just cut off from supply, whether or not we have fuel shortages.

And so I think it's important to recognize, and I think like my panelists have that different events have very different outcomes in our markets, and coming up with different products and methods are going to be very specific to the type of extreme event that we're looking at.

So something that might work for extreme cold might not necessarily work in the case of hurricanes or super storms. And something that many of my panelists brought up that I very much agree with is the importance of shortage pricing, and getting shortage pricing right, and of course the different ISO's and they can speak more specifically to products.

But something that we've been looking at at EPRI is thinking about how we can almost forecast reserves, and the importance of using dynamic reserves. Folks have been thinking about dynamic reserves for renewables, but why can't we then also do that for weather and temperature.

And so including specific weather events or just temperature itself and forecasting dynamic reserves might be something that we can look into in the future, and we're doing preliminary studies, but of course not necessarily implemented. Thank you.

MR. WHITMAN: Thank you. Next and last we have so far it is Anne.

MS. HOSKINS: Thank you. Hello everyone, and it is a privilege to be here. I want to just take a minute and just what Sunrun is for those of you who may not know. Sunrun is a distributed solar and battery company, and I really appreciate the opportunity to join the panel today because so far I haven't heard much mention of distributed resources.

And I'm not sure there was a lot of discussion yesterday either. And my main message for my participation today is don't forget the distributed resources. We are going to play a critical role, and have played a critical role in the past year in dealing where we have had very serious outages.

Last summer, excuse me, in California we were called personally by the Commission -- the Public Service Commission here to ask if we could get our customers to participate. As if we could get our customers not to charge. Ask customers to share their power, but we weren't compensated for it.

And so we had been working very hard with CAISO and with the California PUC to explain that you have all of these resources that are available, that can be available to help not just the individual but the system at large. And in fact there was something close to 3,000 batteries available last August, about 150 megawatts, and those batteries -- I mean there were more than that available, but those actually voluntarily participated and helped to prevent the outages that everyone was very concerned about.

But the capacity was actually much greater than that. There was an estimated 530,000 megawatts. And since that time there are thousands and thousands of more batteries that individuals, companies, schools have installed. So we absolutely need to have this taken into account as we do our planning.

The same situation happened in Texas where we had just recently entered the market. But we had hundreds of customers who were able to not only back up their own house, keep their solar operating, but actually have their neighbors and others participate.

So that's my main message. You're going to hear it again later in the questions. But the other point for FERC is fortunately we do have the Order 2222, which is going to play a tremendous role we believe in ensuring that these resources actually are able to participate in the markets, can be compensated fairly for that, and can really be part of this resiliency discussion and reliability discussion.

We have some concerns. We are very optimistic about New England ISO and PJM, who we think are very sincere in their efforts to try to work with distributed resource providers to make sure we can get the right plans in place to make this work, but we're concerned about other ISOs and RTOs who are saying they think they've already done what they need to do.

The fact is it's not done. Except for New England ISO, we are not compensated for any capacity in the RTOs and ISOs, so we look forward to working with FERC, working with other stakeholders, and all I would say is that these are resources that individuals are investing in that are available to make our system more reliable and resilient and we just can't forget that thank you.

MR. WHITMAN: Thank you. We also have a question later on oriented more towards flexibility demand which might incorporate these questions in the comments that you have. If there's no other, are there any other questions, comments, just starting on this particular on our first question? If there is no one else then we'll go with our next, we'll start with our next question thank you.

MS. TOPPING: Great. For our next question what current practices exist with respect to recalling or cancelling non-critical generation and transmission maintenance outages during a reliability event? Are these practices sufficient to ensure that all possible resources and infrastructure needed to address an extreme weather event are available when such events happen unexpectedly?

And I'm looking for raised hands. I see Anne's hand up.

MS. HOSKINS: Apologize, I just forgot to take my hand down.

MS. TOPPING: Okay. Let's go to Wes.

MR. YEOMANS: Yeah thank you. Yeah the New York State during extreme heatwaves and in the winter is a very tight, transmission electric system. The great majority of the load is in downstate, southeastern New York, Long Island, New York City, a lot of generation capacity in upstate in what I would call limited transmission.

So it is very important in predicted tight conditions, or unexpected conditions that we can get transmission. I recall there may be more important don't let it out in the first place for ordinary scheduled maintenance, you know, forced outage is unavoidable, but if there's the ability to move scheduled outages to other low level time periods or less stress conditions we always strive to do that.

We do have the authority to direct transmission owners to recall transmission lines as need per ISO TO agreement that we executed in 1999. The agreement grants the authorities abilities, we take that very seriously. At the highest level we just generally do not allow any long-term transmission outages in the summer months, or even December and January if they do not have recall time.

So in a world of transmission infrastructure we can recall it and get it back. And so if we work with the transmission owner and they say they can get it back in 6, 10 to 12 hours, or maybe even 20 hours they we can allow some longer term outages, or we'll watch the weather carefully, and we think we have confidence out about two or three days.

So if we have a recall time less than two days then we can allow some significant mission maintenance to work. I mean if it's 75 degrees in July for a week there's no reason a transmission owner can't get some work done, but we actually require a fast recall time if conditions change, or if the weather forecast change.

Now of course, that results in a lot of maintenance being pushed out in the spring and the fall. But anyway, we will allow short outages. We will allow longer outages with recall times, and then of course we try to move this outage work into the spring and the fall and stay out of December, January.

And then a lot of that is true with the generation capacity. We have a process where we evaluated what our predicted capacity excess margins are, and if a generator/asset owner wants to take maintenance, and we do support maintenance, it's the maintenance of the generators and transmission to help avoid forced outages, or very supportive of getting scheduled maintenance completed.

It helps. We have a process on the generation side to look at capacity margins, and if we have sufficient capacity margins we'll let a generator take a long outage to make repairs. And we always support that, allow that, but generally in the summertime we won't allow long-term outages.

We will grant a short outage if it's in a two or three day time period, we need to forecast weather and wait for that peak load, so.

MR. WHITMAN: Thank you. I think our next speaker is Renuka.

MS. CHATTERJEE: Thank you. Pretty similar to what Wes mentioned, MISO has the authority to reschedule transmission outages and cancel the generation outages as necessary again. The authority that comes will all the responsibility because ultimately when you defer maintenance you could be perpetuating generation performance problems, so we don't want to necessarily move maintenance down the road all the time.

But that said it is becoming more increasingly every day, summer like spring and fall days, and winter like spring and fall days are putting pressure on the maintenance seasons, our traditional maintenance seasons. So we are looking at how do we make you know outage planning and more continuous activity, and opportunistically take outages?

And for those of you who have looked at MISO's recent history I mean aside extreme weather events most of our emergency actions are actually in the shorter months or the maintenance months. Primarily because we are trying to achieve access at demand response which we'll get to in a later question, the point being our shorter months seem to represent the highest amount of risk because that represents the highest number of vulnerability in terms of generation resources following availability et cetera.

So in terms of is it sufficient? I don't think it's sufficient. We're trying to do additional things like maximize transmission line ratings, or look at switching options to kind of minimize that risk that we are seeing in the shorter months. We think again moving to some of that seasonal construct other places will allow us to make that risk more transparent so we can actually adequately plan you know.

Again different maintenances are our goal. We do want to get the maintenance complete, so we have the generation available for the highest risk times, but that is putting a lot of pressure in our shorter months for MISO.

MR. WHITMAN: Great thank you. Next is Amanda.

MS. FRAZIER: Thank you. So to Renuka's point I agree with her that you know you don't want to defer generation outages if you don't have to because deferred maintenance outages quickly become forced outages if the problem is not addressed. And so this coordination is really important. And going back to the question one Dr. Patton was talking about shortage pricing, and the importance of having pricing that creates the right incentives for generators to be online.

And part of that is that all traditional generation tends to take it's not maintenance outages at the same time which is either in the spring or in the fall when there's less opportunity for a pricing event. And what we have seen that create is concerns actually happen most often in the shoulder months because that's when an unexpected weather event can really create a concern.

In ERCOT in April of this year the ISO actually announced conservation -- requesting conservation on a day where it was unusually hot for April. It wasn't unusually hot for Texas standards, but for April it was, but because there was so much generation on outage they were concerned about potential shortages.

That said, a lot of work has been done in many of the ISO's on coordinating commission and generation outages. Something that has not had as much focus is coordinating electric outages with gas outages, gas pipeline outages, maintenance outages, and that was an issue that actually occurred in again in ERCOT in 2019, and what's interesting is that gas pipelines because their high-demand system is in the winter months, they typically do take their outages in the summer months when their demand is the lowest, but of course the power side demand is high in the summer months.

And so more coordination. I know we're going to talk about this again on the next question, but more coordination from an outage perspective between the power industry and the gas industry is also something that the Commission should look at.

MR. WHITMAN: Thank you. Our next speaker is Anne Hoskins.

MS. HOSKINS: Hello again. So I do want to mention that one of the drivers for why people are installing batteries with their solar system, particularly in California, but also in Puerto Rico is when transmission systems haven't been working. You know when there have been the forced outage, or required outages, intentional outages by PG&E in particular where we are having days, you know, it went for a few days a few years ago, now they're shortening it.

And so what the incentive has been for customers to go out, invest in their own batteries so they can continue to generate their own power. And because of that you know we are getting this large, you know, large amount of solar and battery systems across California and across other states where we've had these kind of reliability issues.

So you know once again I think what we should be thinking about is if we know first of all that unfortunately this seems to be -- will be a common occurrence in California, but as we see these issues and we have the issues in terms of just having to plan to do outages, is to start bringing this into the planning process, and to realize that there are going to be increasing amounts of solar and batteries.

And as long as we can figure out how to compensate those for what they're offering and which I do believe can be seasonally adjusted, it's just something we have to keep into account. We have certainly seem some studies of how that the increase in batteries and storage have resulted in some reductions in the need for transmission build in parts of the country.

But I think it's particularly helpful in this context to think about how they can be considered a resource for when you have to have outages to maintain some of these systems which are quite old and we need to make sure they have time for their maintenance.

MR. WHITMAN: Thank you. Actually Anne I'd like to ask a follow-up on that. You had mentioned that some of the DERs in California were actually called in an emergency. Related to the interconnection and metering were they connected in such a way that they were responsive to the bulk power system?

Is there anything interesting or inciteful about the interconnection process for these resources that would be going forward?

MS. HOSKINS: Well when I say called I mean physically a phone call to all of us from the CPUC which is the biggest challenge right? I mean we actually don't have the system set up yet to either call or to compensate. I mean we do have some -- the DER program and others through CAISO, but there's just a tremendous amount of work that has to be done and my understanding is that there are some interconnection challenges along with that.

But if you looked at this as a resource that really was available to come by capacity which we believe it is, and found a way to compensate it, then there's no reason particularly with the aggregators that are now available, that this could not be something that could be called just like any other type of generation resource.

But it was really a situation which was very dire, and I think that policy and regulators were trying to figure out what do we do to you now prevent you know this tremendous outage across California. And so they started calling distributed resource providers to ask us to voluntarily take action which of course we did, and we do view ourselves you know as having a very important societal role to play.

But I think we're at the point now where we see that these are not one off occurrences, that they're happening repeatedly. That it's just time to realize that this is a resource that does provide capacity, that is available quickly, which is the other benefit, and to be brought into this process in a more significant way.

MR. WHITMAN: Thank you. Next I think it would be useful as David has pointed out because he has responsibilities across multiple RTOs, maybe a comparison across the RTOs?

MR. PATTON: Yeah thanks Peter. Yeah so I think it would be useful for the Commission to recognize that the authority to coordinate outages is significantly different RTO to RTO, so New England I think has a pretty good tariff authority to coordinate outages because they can deny outages based on their estimated economic impact on the system.

So if it looks like for example that a generator wants to take an outage when there's a line outage into an area and it's going to cause congestion, and on that basis they can deny the outage. That's not the case in MISO, and for years we've been recommending that MISO upgrade its authority under its tariff because MISO can only deny outages when it finds a reliability concern.

And the problem with that is that you're first going to see an economic issue before you see any reliability issue and by the time the reliability issue happens you're scrambling. So we've seen number cases where a major line into a load pocket is out at the same time a major generator in the load pocket is out and you end up with severe congestion.

That's a case where MISO technically can't deny the outage because it's purely an economic impact, but it's also a case where the system is vulnerable to reliability problems. If another unit has an outage in that pocket, or there's some weather events that creates an additional outage, so I think improved authority would be good across the board. But on the incentive side I did want to say one more thing.

How incentives connect to this -- that shortage pricing definitely provides very good incentives for generators to schedule to coordinate their outages and it brings their incentives into alignment with the RTOs, so when they're asked to move an outage it will generally be in their economic interest if shortage pricing is good.

But one thing you have to realize is that in markets with capacity markets we deliver a lot of the revenues to generators in the form of SE payments that would normally come in the form of shortage pricing revenues in an energy only market. So the one thing we don't do well in the capacity markets is we don't hang generators based on the fact that they are there during tight conditions, but they are contributing to reliability.

So we've been recommending in New England, New York and MISO that they all approve their accreditation, and have it be based in large part on generators being there. And that would help on outage scheduling because if you know you're going to lose capacity revenues because you're on outage during tight conditions, then it brings your incentives into alignment again with the RTO on outage scheduling.

And the last thing I would say is the one thing you should know in all of these discussions is that there's one key class of participant that doesn't have good incentives, and that's the transmission owners. If they have outages occurring that create problems, create tightness or create outages, they're not harmed financially.

And it's the same problem that we have trying to get them to submit higher ratings so we can better utilize the transmission. They just are almost immune from the market incentives that generators and other respond to. So in that regard thinking about how we can get better incentives to the transmission owners is really valuable.

New York is the only one that does something in this regard in that they allocate some of the transmission right shortfalls associated with outages back to the transmission owners, kicking the outages. That would be great for everybody to do. Thank you.

MR. WHITMAN: Thank you. Good insights. Wes?

MR. YEOMANS: Yes thank you, this is my second round. I failed to mention something in the area of transmission for extreme weather of course it makes sense to recall transmission outages, and don't even schedule them in the first place if there's a chance of extreme weather.

But even different than that something that might be unique to New York or maybe not, is if we are predicting severe thunderstorms, we had some transmission contingency cases we put into our market system referred to as the transmission service cases. And rather than our ordinary N minus zero to normal ratings, N minus 1 to LTP emergency ratings, we actually operate for some additional contingencies assumed already out as part of our market dispatch.

So quite frankly from a practical perspective that backs off the power flows on the transmission, even though it's in service and it has not incurred that first contingency yet, but it's in anticipation or preparation of what might be sort of lightening strikes. And it's just being prepared on the front end rather than loading the lines to their full capability and then having to redispatch on that after the first contingency because you might have second, third, or fourth one shortly after that.

And we did. I was in 10th grade but in 1977 we had a negative event in New York where some thunderstorms passed by southeastern New York, and knocked out several transmission lines in New York City, and unfortunately New York City became unsynchronized, and we had a blackout. Okay I wanted to offer that, thanks.

MR. WHITMAN: Thank you. Finally Anne do you have a follow-up, or is your hand up?

MS. HOSKINS: Sorry I'm not following the rules, I'll fix it.

MR. WHITMAN: Thank you. Then let's go on to the next question.

MS. TOPPING: Our next question -- given the dependence of electric system reliability on other systems, on gas, water, et cetera, what situational information related to those other systems is critical to electric system operator awareness during extreme weather events?

Should electric system operators consider modifications to their control rooms, or to software to enhance their situational awareness related to these other systems? I'm look for raised lands, let's see. Let's start with Amanda.

MS. FRAZIER: Thank you. So you know we experienced the power outages in ERCOT this past February, and one of the things that was unique in this event compared with for instance in 2011, was the significant disruption in the gas pipeline system.

And you know as the country decarbonizes, it will become more reliant, at least in the short and medium terms, on reliability gas supply for that flexible you know, flexible generation to balance out the renewables that are coming online. And those gas generators that will be needed will have lower capacity factors, so that's going to create you know some real misalignment of incentives in terms of contracting for gas supply as generators are more reliant on reliable gas, but also need more flexibility for when that gas is provided.

And so you know we are very interested in a lot more focus being paid to the gas pipeline systems, both the interstate and the intrastate that falls within FERC's jurisdiction through Section 311 and the Hinshaw Pipelines and creating that additional transparency that's needed to have that coordination. You know FERC regulates those intrastate pipelines, slightly regulates those intrastate pipelines, but it has full jurisdiction to regulate further you know if it finds that there are reliability issues being created, and/or if it finds that issues on those pipelines are affecting its regulation of interstate pipelines.

So currently the light-handed regulations are that they require that rates must be fair and equitable, that they must provide open access and be non-discriminate. They have to have a statement of operating conditions. They have to offer firm, or interruptible service, and there are some reporting requirements.

But what's not required on those Hinshaw in 311 pipelines are standards of conduct that separate the transmission and marketing functions, transparency is not required, so there's no electronic bulletin board similar to the ones that are required for interstate pipelines.

And so and there's never been any enforcement actions that we're aware of on pipeline operators under Section 311 or the Hinshaw Pipelines. And so our experience in the February event was that coordination was very difficult just because information was not available, and so that lack of transparency -- and that includes both the availability of capacity and pricing transparency, really created concerns that we think will only continue as we encounter additional extreme weather events going forward.

MR. WHITMAN: Thank you. I'd like to -- Commissioner Christie has a follow-up question.

COMMISSIONER CHRISTIE: Yeah. I have a question for Dr. Patton if I could go to Dr. Patton. Dr. Patton in your last comments you talked about the importance of scarcity pricing in the energy market, and then you also talked about the importance accurately of accrediting capacity in the capacity market for reliability.

At the very end of your comment you said we also need to extent the principle to transmission. Would you elaborate on that? I didn't quite get it all from what you said, just tell us more about your idea about extending that principle to transmission please.

DR. PATTON: Yeah, so unfortunately almost none of the compensation that transmission owners get is market-based, it's all embedded cost recovery through regulated rates. And so if transmission owners can do things to increase the transfer capability on a constraint, they don't benefit from doing that.

If conversely, on the other side of the coin if they take outages at very bad times, and it creates severe congestion, there's no real harm to them doing that. Now there will be market effects for instance, the RTOs all sell financial transmission rights. They're called different things in different markets. They're TCC's in New York and FTRs in a lot of other markets. And what happens when a transmission owner reduces the capability by taking outages is large here and woe them, potentially fail to be able to collect enough congestion to pay the transmission rights.

So you may find on a particular path that the RTO is 5 million dollars short of what they would need to pay those transmission rights because they can't honor them because the transmission owner took an outage. So in New York some of that 5 million would be allocated back to the transmission owner who took the outage.

So that's an example of one small way that transmission owners in one location are being exposed to market incentives. But I think you know we could definitely brainstorm how to potentially give them access to some market incentives because even when we talk about for instance your transmission incentive ideas and policies and MOPR and so forth, it's all sort of characterized as should we increase or decrease the rate of return that transmission owners receive, which is all back in the sort of embedded costs mindset.

There's no real discussion that we tend to put these on our comments of finding ways of delivering market-based revenues to transmission owners to try to start to give them better incentives. So make's sense.

COMMISSIONER CHRISTIE: Well I think it's the start of a discussion. I've love to hear more from you if you want to follow-up on that after this, and scope out an actual proposal and flush that out. I think it's a very interesting concept.

DR. PATTON: Yeah sounds good.

MR. WHITMAN: Thank you.

COMMISSIONER CHRISTIE: Thank you.

MR. WHITMAN: Getting back to going back to our questions on situational information. The next person is Wes. If you have a comment? Okay let's move on to Renuka's.

MS. CHATTERJEE: Thank you. Fuel availability is one I think that has a lot of attention as it is under the electric gas coordination. As of now MISO conducts an annual winter fuel survey assessment that allows us to collect some information on you know fuel availability, specifically with regards to actual gas availability.

And honestly I mean, thinking about fuel availability for gas and coal is no different than how you think about the emphasis on wind and sunshine, for wind and solar resources. That said, you know how do we think about who should ensure fuel availability.

Today all we see as an RPO is to the market offers, so if the generator tells us it's available at a certain cost then we know that they have fuel behind it. I assume they have fuel behind it, but if we learn something from the arctic event and prior cold weather events we will work with members one on one to make sure that we would issue them starts so they can procure gas.

Many years ago the Commission led the charge on aligning the electric and gas coordination timelines that I think is paying off now. We probably need more coordination in the more forward looking we get, two day ahead, three day ahead timeframe to think about how do we improve the fuel availability, fuel certainty so we can count on the resources appropriately?

Again you know it's not to say that the RTO should have their own forward manager and fuel availabilities. They keep talking about how do you ensure.

Lastly, on that particular one that increasing renewable resources, you know if you put in a requirement for a forward fuel transport, and the gas unit is only going to run a few times a year, then it's not the cost effective way.

So I think there's a lot of debate and discussion to be had around how do you ensure efficient fuel availability for the times when you need. I think that's up for discussion in the investment.

MR. WHITMAN: Thank you. David do you have additional comments?

DR. PATTON: Yes. So I echo a lot of the comments that have been made, especially Amanda I thought made some really good points on transparency and the need for transparency. I think a couple things I would say is the gas procurement and trading that takes place is I think okay to get non-stressed days, but it lacks the amount of coordination you need when participants when gas starts to become scarce and participants are trying to acquire it and allocate it, the gas trading that currently takes place is really not very good. And it is the reason why you see dramatic spikes in gas prices, and then when the psychology changes, and the concern over gas availability goes down gas prices tend to drop like a stem.

So that signals that we could do a lot better at coordinating gas and particularly pipeline capability. Although it doesn't require the same degree of coordination that the delivery of electricity does because the physical characteristics of delivering electricity are far more complicated and rigid than gas. You have a little more control over gas delivery.

But still I think it would be very useful to think about can we improve how we coordinate gas trading and the dispatch of gas around the system. The idea of a gas RTO function would deliver huge benefits in the sort of tight gas conditions, and I know the pipelines probably would not be crazy about that, but nonetheless it would be extremely valuable.

And one final comment just in terms of like short-term improvements. The idea that you don't trade gas over weekends is -- well surprising. I could use more inflammatory words, but it is surprising to me. If you look at the arctic event it happened over a weekend, a holiday weekend, so participants were in the position of having to procure and buy themselves gas on Friday that extended all the way until Tuesday which was made the whole management of the gas suppliers you know far more difficult than it needed to be.

Because it's really hard to figure out I think when you're trading on Friday what you're going to need three days later. Okay, that's all my comments.

MR. WHITMAN: Great, thank you. Robin?

MS. BRODER: Thank you. I think my fellow panelists have done a great job of talking about the difficulties with the gas interface and the continued challenges there. But I wanted to address the second half of the question and talk about some work we're doing in EPRI, the control center of the future, and focusing more on that end on what that control center will look like.

And so one of my colleagues has been looking at increased situational awareness in the control center, and especially to do with alarms, standards and philosophy. And especially as more information is going to be coming due to renewables and DERs on the grid, improving the way that operators are able to see this information on any amount of information available to them.

In the opening remarks that I submitted I encouraged people to go look at some of the information we have there in some of the reports that are available to anyone. And basically, some of the focus that my colleagues are looking at you know is increasing the amount of weather information. This has really been at the core of you know electric utilities operations, an so having some simple information available and especially the interchange between transmission distribution, customers, distribution, transmission and gas and transmission.

And we're encouraged with what's coming up with FERC Order 2222 in this regard. And so one of the things that we're also doing here is looking, developing a tool, a system resiliency evaluation methodology and tool, and basically helping system operators evaluate how at-risk their systems are for these extreme events, and the potential to really expand this across different domains. I'm think about cascading events, or N minus X events.

And this is in early stages of research at the moment, but we're encouraged to move forward, especially as you know, the different resources on the grid and improved DER. And so this is again I encourage you to look at the remarks that I submitted for more information on our controls of our future work, thank you.

MR. WHITMAN: Thank you Robin. Wes, do you -- you had your hand up earlier on our question related to control rooms and situational awareness?

MR. YEOMANS: Yeah thanks. I apologize. I don't know how I dropped off, and actually I lost a little time because I thought the problem was the same. But be that as it may yeah, just coming back to what I believe is question three regarding critical gas electric loads and we're all paying attention closely to what happened in ERCOT, what we can learn from that. But quite frankly, in the last five or ten years we have gone to the New York gas company really focused in our states more than once, a couple times, to talk to them about their compressors and motor generated, motor driven compressors versus gas turbine driven compressors.

And gone back to the electric utilities to make certain that those large important interstate gas pipeline compressors are not on the utility load shed scripts, or lists I should say. So we're pretty confident on that. But to be quite frank I think there's an opportunity for us to go back and ask more questions, first of all not just the electric motor driven compressors, but the gas turbine driven, and other auxiliary type equipment that if their start up generators needs start that they rely on utility, and let's make sure they're not on the load's shared script.

And maybe even other stations, taps, or just other types of gas stations. So we're going back to the electric industry to really again ask for a comprehensive list of critical loads, and then go back to the utilities and make sure those account, and those services are not on the load shed script, so that's very important, so yeah thanks, I just wanted to offer that.

MR. WHITMAN: Thank you. If there are no other comments I want to ask if the Commissioners have any questions at this time that they would like to ask. If not, we'll go on to our next question.

CHAIRMAN GLICK: Peter this is Chairman Glick. I appreciate the opportunity here, and I noticed that the questions here -- there's many questions and they're all really good. I was wondering if it's possible just in the interest of time maybe we can make sure. I was interested in the last question in particular, and if it's okay with you to jump to.

And more specifically demand response. You know I think we saw in the California situation last August during extreme temperatures that demand respond played a very significant role in keeping the lights on, and for those days of rolling blackouts to eliminate the impacts.

I'm curious if the panelists have some suggestions about what we might need to either from a FERC policy perspective, or at least from RTOs and the way they operate the markets. There's more that needs to be done to encourage to facilitate their response during extreme weather conditions.

MR. WHITMAN: Okay let's start with Anne then.

MS. HOSKINS: Sure and hello Chairman. Nice to see you. So I spoke earlier about the California situation. I don't know if you were on at that time, but you know clearly that was something I'm calling in from California, so something you know very much on our minds right now as we're now in fire season again.

And you know I do think as I mentioned earlier you know, demand response or just calling on demand side resources. There is more work that needs to be done to figure out some compensation for it, but you know, and I know there's efforts underway, but it really needs I think additional attention, and you know perhaps support from FERC would be helpful on that front.

But I've also heard going forward in terms of how this is all going to work is that there are some metering and telemetry issues that you know we can turn some information in on that you know as we start to look at how you really are -- particularly if you're going to be able to compensate these resources.

You know making sure, you know in our situation right we have individual homeowners, and we are able to aggregate those systems and serve as a third party aggregator. But we want to make sure that there aren't a lot of you know complicated interconnection roles that are impeding this as well as extra metering requirements when we believe that there are many opportunities for submetering that could really make sure that the flexible resources that are there can be utilized.

So you know I'd be happy to you know send some additional information in on that, but that's what I understand is the combination of just a lack of compensation mechanism as well as some sort of technical metering issues that if we could work those out could really make a big difference, and it is going to be critical again this summer we're sure.

Everything we're hearing about is that you know we have very dry conditions, and you know a lot of concern about what's going to happen with the wildfires as we go into the summer. So thanks for asking.

MR. WHITMAN: Thank you. Next Amanda please?

MS. FRAZIER: Thank you Chairman for the question. I think it's an important one and a good one. And one of the things that I know is most important and from my perspective is making sure there's a pathway to get the incentives all the way from the wholesale market to the retail customer.

And I think this Commission has done a nice job in promoting demand response and creating orders that facilitate additional demand response. But you know that needs to be coordinated also, and I'm sure that there are state utility commissioners listening as well, that needs to be coordinated from the state's perspective to make sure that there are products that can be developed that get the benefit to the customers.

So for instance, you need to have as a retail supplier, you need to have the ability to get access to the customer's information in relative near real time, so that you can understand their usage pattern. You can design a product that is cost-effective to the retail supplier, but also beneficial to the end use consumer.

And then once you have that type of information you can structure a product that will pass those incentives down to the customer. As an example, in Texas we have you know retail businesses here where we do have demand, voluntary demand response offerings that we give to the retail customers, and they can get paid to curtail, you know, at our request.

We can offer additional you know benefits for compensation if they choose to respond to a voluntary curtailment, and a lot of times customers will actually respond on their own just as a good citizens. If they have the information that they need about when conservation is required, and why it would be helpful.

Because it's you know there are more complications in getting that information to the retail customer, I think you see in the development of demand response really proliferate in kind of the industrial space because they have access to the wholesale market, so they can get those benefits directly, and they can participate directly with the wholesale market.

As connecting back to the last question, another issue that we saw pop up in the February event in ERCOT that is something that probably all RTOs need to consider going forward was there was actually demand response from critical infrastructure, so critical gas infrastructure was committed to provide demand response product through the wholesale market, either in the form of an ancillary service or a reliability service.

And because of that they were incentivized -- required really, obligated, to curtain their load in response to the call for conservation, and it created this new loop effect where they weren't able to you know produce gas and put it on to the system.

So there should be some oversight from the RTOs and ISOs to make sure that we're not creating a situation where demand response is cannibalizing a critical fuel support of infrastructure needed to deliver power reliably.

MR. WHITMAN: Great thank you. I think that's actually a really good point that we hope to get back to later on. Next is David, and then following Ms. Renuka.

DR. PATTON: All right. I'm going to shock you all by telling you how important shortage pricing is in this regard. Now I don't want to beat a dead horse, but and most roads lead back to shortage pricing.

If we intend to properly compensate a lot of the responses either to intermittent resource output dropping off unexpectedly, or extreme events, or other factors that can threaten reliability, the price we set during the event in real time becomes a critical component of the incentives that you give folks to make the kind of decisions that you want them to make.

And in this case we're talking about demand response, which I think is incredibly valuable, and if we can get most of the incentive for demand response embedded in the energy price, rather than the capacity market I think we'll be far ahead in terms of providing good incentive for flexible demand response.

What happens when you try to pay them in the capacity market is they accept an obligation. They don't really want to curtail, and it turns out that at least in MISO and some other places, the ability to utility demand response is significantly reduced because often they indicate they need a relatively long amount of time -- of lead time, to be told that they're going to be needed to curtail.

And often times the extreme events, or the emergencies happen with only an hour or two notice, or even less than that sometimes. So then you know in a lot of cases we've looked in MISO and the amount of the demand response that they purchased in the capacity market versus the amount they've been able to utilize have been very, very different.

And they're making some changes to improve that, but I think there's an inherent problem in relying on compensation in the capacity market, rather than through the energy market where they get paid when they help, and they don't get paid when they don't help.

I do think to the maximum extent possible treating, trying to get them settled on the demand side is a big improvement over settling them as if they're a supply resource. I don't think we can completely do that, but for all demand response as a market monitor we're continuing to see problems with trying to establish baselines and seeing cases where the demand response resources are establishing baselines that don't reflect the amount of load they're actually going to be able to cut when you get to the point of calling them.

So having them be on the demand side eliminates that particular issue. So those are my comments.

MS. HOSKINS: Can I follow-up to that, or?

MR. WHITMAN: Sure.

MS. HOSKINS: Oh great, thanks. Yeah, and there are a few things there that I feel like I have to respond to from the demand side. One is that you know when you're working with solar and batteries and aggregating them, which is what we're dealing through virtual power plants, and even through the bid that we made that was accepted in New England ISO a few years ago, is one of the benefits is it's not like typical demand response because we are able to work through the thousand or so units that we've aggregated together, and customers can continue to have access to power.

It's not an either/or choice. It's not as though they have to agree that they're not going to have their air conditioning and give up their power. And I know as a former regulator that was a concern after a few times right. You might get you know customers getting a little concerned the third or fourth time they were called.

But that's not the situation here. And we've got the analytics now that we are able to optimize, make sure that there's enough left in the battery for the customer, and then you're able to share the other power. And so it is a firm capacity resource, and I think it's really important that people understand that, but this is not your typical demand response. So that's number one.

And secondly, I don't think this is something that has to be kept on the demand side, and we've certainly seen in New England ISO they are counting this as a capacity resource. But also one of the reasons that I mentioned the telemetry and the metering is that we do have the ability.

We agree, we should not be using baselines. You know we think that that's really kind of old school. That we have the technology now. We can meter exactly from the inverter how much power is being shared, when it's being shared, and so I think that we just need to move beyond that and recognize that we have the technology, we have the customers that want to participate in this.

There's a very important role for aggregators to make sure that there is the ability to respond to signals, and you know I certainly am hopeful that you know during the 2022 process and otherwise that you know people can learn about the opportunities that are out there now with this technology, and we can find a way to make sure that it's really brought into the markets, thanks.

MR. WHITMAN: Thank you. Next Renuka?

MS. CHATTERJEE: Thank you. I would build upon what Anne and David have said. When I think about demand response I think about it as the last step before you're going to control load shed right, so it's really important. And it's best to think about demand response in three different categories. The first one being very sensitive demand response.

So much to Anne's point you know you could design this product for you know it could respond to parties, it could have specific performance expectations and it's a known quantity you get in a known amount of time, so 30 minutes, two hours, the entire time.

The second category being demand response behind emergency declarations. So much of my system demand responses behind emergency declarations and somewhere between 12 to 14 gigawatts to be precise. So it's a large quantity of demand response, but the trick is forecasting emergencies 12 hours, 24 hours in advance, and calling upon these and actually making sure that it's available, that it's actually running so the demand can be used.

And the last category of demand response tends to be this voluntary you know load reduction of public appeals and most processes, all of the RTO processes I'm familiar with it's too late in the process. You know just before, 30 minutes before load sharing we're going out and asking for public appeals, we are relying on the public to reduce the demand, you know, in short time.

Most of the public may not be even paying attention to some of these announcements. So this gets to be the most variable or unknown quantity. You could get a lot, or you could get nothing. It's pretty subjective from that perspective.

So pushing more demand response into that price sensitive category with the distributed energy resources type products I think is one way. We also should look at how do you improve the demand response that's only available and under emergency condition. You can't eliminate it. Some of it will still be available just because of how the industry works.

How do you improve its performance, and lastly how do we leverage public appeals. My experience sitting through a number of emergencies of MISO's it too late in the process, and there's not enough time for the consumers to react and the market to respond before you go to load shed.

MR. WHITMAN: Thank you. Let's go to Mads and then Amanda.

MR. ALMASSALKHI: Thank you for the invitation. And I know I've jumped in a little bit late, but that's basically -- I appreciate the comments so far, which in my mind have really focused on the fact that you know through the first three questions we've really been focusing on the need for being more dynamic, be more responsive.

And I spent the last 10 years or so looking at distributed energy resources. It sounds like there's a lot of misconceptions. Unfortunately still rummaging around the electricity industry, that somehow demand response has to be this big hammer when actually today through analytics, optimization and advanced control technology, it's really becoming acceptable.

And what we're looking at today is you know terawatts of renewable generation will require gigawatts of flexible energy, or flexible demand. And that flexible demand can really help us respond to certain limited capacity on the transmission system, because distributed energy resources are everywhere.

And so you can have distributed energy resources responding in certain regions as storms come in, which means we can use these control algorithms that manage thousands of millions of devices to prioritize critical loads, by deprioritizing non-critical loads. And we can do this dynamically. we can do it in real time. And in most cases we have sufficient submetering available to us through very cheap sensors over the last 10 years.

So really go beyond baselining and really talk about how do we provide firm resources up front that can help during the short bursts -- I think let me just see the name, apologies, so this is David's shortage pricing which is you know DERs are well-bred for this purpose.

And I also want to point out that the comment around DR, dynamic demand response today you know, this is not your parent's DR anymore. We're really talking about flexible and nimble resources, which is why I'm super excited to represent you know not just the University of Vermont. I'm not just representing Pacific Northwest National Lab, you know, which has been the first place of transactive energy, but I'm also representing a small startup company in Vermont called Packetized Energy which has a platform for DERs called Nimble, which is really illustrating that DERs today are not the hammer of yesterday.

It's really a scalpel that can provide localized, specific, and very fast services based on the needs of the grid for the markets.

MR. WHITMAN: Okay thank you.

MS. TOPPING: All of this feedback has been really helpful. I'd just like to read the entirety of the question because I believe we've gotten a lot of looking back to some, but not to the later part of the question as much, so I'll read that right now.

What are the most effective means of engaging flexible demand to mitigate emergency conditions? Are there methods to improve the use of flexible demand in addition to the solicitation of voluntary load reductions through mass communications during extreme weather?

Do existing interoperability and communications standards enable robust participation of flexible DR to address climate change and extreme weather challenges, or is it more consensus-based standards development work needed by the relevant stakeholders? And let's see David would you like to speak next?

DR. PATTON: Sure. Okay so a couple things, there are a couple other responses to my comments, and I think I don't disagree with either of the responses by Anne Hoskins or Mads. I think in the case of solar and batteries those look an awful lot like supply resources to me, even though they're DERs.

I think not mixing up controllable supply that happens to be distributed, versus true demand responses is pretty important. But even with the demand response, whether you're talking about supply, or to demand response in the kind of optimizable very controllable demand response that Mads was talking about.

I think in both cases something that we're going to need to see to be able to improve on is recognizing locationally where it is and delivering locational price signals that would compensate those resources accurately depending on where they're located. Sometimes that compensation would be the same regardless of whether located if we're having a market-wide shortage.

More often it's going to be the case that we have very specific locations where we're having reliability problems, and congestion that the ability to access those resources will, I agree with you, be extremely valuable, but we're not quite there yet in terms of having enough visibility on where they're located in order to settle with them accurately, which I think is in the best interest of the DERs, and the RTOs.

And with regard to shortage pricing I think the reason I keep bringing that up and I think Mads sort of referred to this is that very predictably when we're headed into an emergency, and we're running short of reserves like demand response is not a cheap way to get energy or reserves.

But when we start to go short it can be far cheaper than the marginal value of our reserves. So if our prices for example predictably are going to rise from 500 to 1,000 to 2,000 to 8,000 dollars, and you have because you can control the DR very specifically and rotate it, you have customers that are willing to respond at let's say 200 dollars a megawatt hour, or 300 dollars a megawatt hour.

They can receive very strong incentives to contribute to reducing the shortage if we in fact our pricing shortage is efficiently. If on the other hand, we're in a shortage, but we're pricing it at 80 dollars, then that severely limits the ability to provide good incentives to the DERs to help us in those circumstances which is why emergency pricing and shortage pricing are so important in the near term.

And as we head towards a system with more and more intermittent resources and more uncertainty around their output.

MR. WHITMAN: Thank you. Robin?

MS. BRODER: I think this has been a very interesting discussion, especially thinking about the uncertainty of output of these resources, and thinking of that I wanted to mention that there is an RB program that's looking to address some of these issues. RB put out a program called perform and which is really looking to how can we as you know the power industry address uncertainty and delivery risk.

And that especially is focused on many aspects of the demand side and DERs. It so happens that Packetized and ourselves are part of one of these teams and there's 11 other teams that are really looking at developing algorithms, software, even hardware that's aimed at trying to assess the uncertainty risk of sometimes it's assets, sometimes it's clusters of assets, and being able to give those kind of algorithms to aggregators, to potential BSO's or even to the ISO's in order to help manage that risk.

And so of course this is in the early stages, research stage not yet in development. The teams have been working this year, and for the next two years on how can we solve these issues. One of our proposals is really bringing in concepts from the finance and insurance industry into the power industry, and looking at how we can assign risk scores, so that either aggregators or other people who are looking at these different resources can say well I know with some certainty that this resource can provide me what they want, or they would need to be discounted a certain amount.

And so I think this is an area of ongoing research, and there's many different aspects and dynamics that go into that, but many teams, and I know many of the ISOs are involved in different teams, and so I'm looking forward to this research. It should be pretty interesting in how we can incorporate the concept of risk in order to firm up the uncertainty that some DERs can provide, thanks.

MR. WHITMAN: Thank you. Anne next please.

MS. HOSKINS: Thank you. So I just wanted to mention that you know there are programs now on the state level that are actually trying to give incentives locationally, and so some of those are really happening up in New England. I know that Green Mountain Power has one where not only is there sort of an upfront incentive for customers to get a battery, then there's an incentive when they show up, when they're called, but then there's an extra incentive if it's in a particular area that has a constraint.

So I you know, have people take a look at that. But there are also programs in Massachusetts. There's a clean peak program now as well as just the smart incentive. So certainly there have been efforts I think on the part of some states to try to see how can they not only incentivize customers to invest in batteries, but also to make sure that they have asked to participate when needed, but that an additional incentive, or a focus incentive based on location or time.

So I do think there's some good examples out there that we can learn from.

MR. WHITMAN: Thank you. I think we'll move away from this topic temporarily to Commissioner Clements has some questions.

COMMISSIONER CLEMENTS: Thank you Peter. That was a really interesting dialogue, so I appreciate all those inputs. We could probably hold a whole other technical conference on just that question. I'm going to go all the way from the smallest, cheapest resources up to the biggest most expensive, and talk about interregional transmission.

Mr. Patton mentioned a few things about misalignment of market of the incentives for transmission to participate more dynamically, and I also share Commissioner Christie's enthusiasm for learning more about that. Yesterday there was some conversation about the value of increasing transfer capability across interregional transmission, and Ms. Chatterjee, in your pre-comments for this technical conference talked about the value of RTOs as a resilience platform, and the opportunity for improving seams, redispatch and other coordination in a manner that helps to improve reliability and resilience.

So I'm curious if you could say a little bit more about that and also talk about -- let me make sure that I got everything that I wanted to ask. And the differences that might be involved in coordination at the seams with a neighboring RTO versus a neighboring non-RTO balancing authority.

MS. CHATTERJEE: Sure. Thank you for the question Commissioner. With regards to the you know the RTO's, particularly MISO. One of the things that needs to be noted in our post-February event presentation was how the RTO was able to enable flows from the west to east, the typical you know, sorry from east to west.

Given the south and west portion it was like this drain hold from power, a lot of power needed to get there because of the cold weather. And we had observed flows we had not seen in 14 months, and I say 14 months only because we didn't look beyond that.

The transmission system was carrying 40 percent more loading than we had seen, which means the system was capable. We did have a handful of transmission events that we addressed during the February arctic event, but the transmission really supported a lot of power flows going across the system.

So again as I mentioned earlier, certainly you could have local generation, but you want to have options to the situations to transfer power. PJM was sending anywhere from 10,000 megawatts to 14,000 megawatts, not just to support MISO, but to support to the rest of the MISO.

So there was a lot of power transfer that was occurring, and all of this is in large part due to the transmission that was available in between to make those transfers feasible. Now fast forward as we look into more renewable integration and portfolio evolution. We are looking at a pretty aggressive transmission plan that we put out there, and again that goes to support -- that's not the primary driver, the best way to think about it is when you're building transmission, when you're thinking about what are the business uses on reliability and efficiency in extreme arctic weather events, or extreme weather events.

All transmission and all generation is supporting reliability. It's not about you know no one in the event was trying to have their own personal economic gains. Everyone was trying to support the availability of power where it was needed most.

With regards to you know ISOs an RTOs are market sources non-markets. I'll make a couple of points. First when we are trying to negotiate seams agreements between ISOs and RTOs I think the Commission led the charge many, many years ago I believe in 2004 and 2005 timeframe, that has led to what I would call state of the art coordination between the markets, between PJM, MISO and SPP we have a really advanced mechanism for economic congestion management and support for each other.

So you know again those were significant steps forward in ensuring that the benefits of interconnection outweigh the pain of interconnection. Now when you think about market to non-market seams, the negotiations go much slower, and if you think about those the RTOs and ISOs are optimizing policy across multiple members so the diversity of the footprint within each ISO/RTO allows us to come up with a little bit of a flexibility in how you negotiate.

When you are negotiating with a non-market entity which is actually the entity itself is its own policy, so it's harder to find a compromise. So going forward some sort of you know David and I were talking earlier today. We said performance, but some basic mechanisms or standards for seams coordination of the operational timeframe would be helpful.

Otherwise we are trying to negotiate you know the negotiations to achieve reliability cannot be done without discussions on efficiency and liquidity, and those discussions are taking a really long time. The parallel flow visualization effort that was led by NERC is finally going to give us more transparency to some of the flows on the interregional flows.

But again that itself took almost 10 to 12 years. You know I was an engineer when that project started many, many years ago. So anyway, jokes aside, it's hardly velocity because the change with which -- or the force with which the variables and the DERs are coming forward, we can't afford to take 10 years to get those seams implements in place.

MR. WHITMAN: Thank you. David you had some comments?

DR. PATTON: Sure. Yeah, I think this is a great question because given the configuration of the RTOs and non-RTO areas, there are, especially during emergencies, but even not during emergencies there are significant affects that the systems have on each other.

And Renuka is right that PJM, SPP and MISO have implemented market to market coordination that you know frankly without it I don't know how they could dispatch their systems very efficiently because they cause so many flows on each other's systems, but with non-market areas we haven't been very successful as an industry of getting agreements in place to coordinate the dispatch of generation to where we're affecting each other's systems.

So for example, ACI, TCI, TDA, both of these are areas that non-market areas, even Southern Company, that create significant flows on MISO's system where we incur much higher costs because there's not a good way to coordinate adjustments to the dispatch of those non-market generators to efficiently manage congestion.

And again, as I said earlier, things that raise economic costs during normal conditions raise reliability issues during more extreme conditions. So we're impact reliability, and so we've been recommending those sorts of seams agreements for maybe a decade, and I think Renuka's right, it's very hard to bring them to fruition.

But I think one thing the Commission could really do that would be helpful is require seams agreements between all of these areas, and we'll need some minimal standards. And those minimum standards would include coordinating the relief of congestion. You have in some places required, or in the FERC limit tariffs required redispatch service to allow transmission service to continue to be supported, but personally I'm unaware in non-market areas of any redispatch that's actually being provided in order to supply transmission service.

So maybe making that a mandatory requirement, and so that would be one element of a seams agreement is joint congestion management. The second would be managing imports and exports between neighboring RTOs or non-RTO areas. That's one area where I think there's a disturbing lack of coordination.

I mean the operators tend to get on the phone and talk to each other and try to figure out what to do, but at the end of the day we sometimes see very bad decisions being made unilaterally by RTOs that have bigger effects on the other side of their seam than they do in helping them.

So I won't name any RTOs in this regard, but I would say all of the RTOs we monitor could do a better job of explicitly coordinating imports and exports to try to maximize the reliability of the interconnect. But I think those sorts of agreements won't come about unless they're required by the Commission.

MR. WHITMAN: Thank you David. Amanda?

MS. FRAZIER: Thank you. And just to connect the dots. The dots between this question and open rule making that the Commission has in front of it on dynamic transmission line ratings. You know I think having the transmission operators coordinate those dynamic line ratings at the seams could be an easy and cheap way to make sure that you're optimizing transfer capability between the regions as well.

MR. WHITMAN: Thank you. Commissioner Clements do you have additional comments or questions?

COMMISSIONER CLEMENTS: Thank you for those answers. I have one more question Peter, but I'm happy to hold it if other Commissioners want to jump in. Okay. The last question is two parts. In Texas we saw that you know a lot of market participants took on risk exposure and then they, excuse me, they suffered financial losses.

And the market incentives therefore were not sufficient to incent kind of their range of actions that were after the fact identified as contributing to what took place there in February. So some subset of those actions are within the Commission's jurisdiction, and for that part I'm wondering if you all have a perspective on how we approach the choice between market incentives and standards, and standards/requirements I guess to arrive at an optimal mix.

Appreciating we probably need some amount of both. And then there's a second subset of issues that are not within the Commission's jurisdiction like the lack of weatherization, or issues on gas production practices that don't account for extreme weather.

And so in those cases, and in our limited jurisdictional reach, are there ways the Commission can nevertheless encourage or incentivize those players to get at some of these concerns? And I would like to hear from market participants as well as others.

MR. WHITMAN: Okay.

MS. FRAZIER: I'll start because my company incurred about 1.6 billion dollars loss as a result of the February event. We are the largest generator in ERCOT, and we were fully hedged for our gas supply going into the February week. We had some weatherization issues related to power plant's operation, but also to some cold handling, but the majority of the problems that we saw were related to our gas supply issues.

And so, you know I appreciate your question on how do you balance the market incentives with the requirements, and I think that it's important to have requirements on both weatherization and preparation for events. That's part of you know FERC's role in ensuring reliability.

That said there is no better incentive to be prepared for a storm than very high shortage prices, and exposure to those prices. And in fact what we experienced was that most of the weather issues that we experienced in 2021 were not the same weather events -- or weather issues that we experienced in 2011. Why?

Because we took you know a lot of actions to make sure that we had address those things that were exposed by our experience in 2011. I expect that you will see us, and others respond to what we learned through the 2021 storm and make changes going forward.

That said, the second part of your question is the one that keeps me up at night, and that is that there were so many things outside of our control that impacted us you know significantly in the event, and the largest one of that is the gas supply issue. I agree with you that you don't have jurisdiction over gas and production, but you do have jurisdiction over a lot of the pipeline issues, and that's where you know many of the problems that we saw occurred.

So I hope that FERC will take that opportunity to review its jurisdiction seriously, and consider what changes need to be made to ensure that we do have reliable fuel supply going into the future events. You know one of the most important things and I think low hanging fruit from my perspective is something that I discussed a little bit earlier, and that's just transparency from the gas side.

If we know where the capacity on a pipeline is, and we know you know what the prices are then there's the ability to make a market. I think Dr. Patton brought up an important point around the gas trading limitations there. It is insufficient to have to purchase gas for four days going into a major winter event, and in fact we had you know, we saw curtailment to our power plant even on some contracts that we have days before the winter storm even occurred because the gas wasn't going to be available to trade with us during the middle of the storm anyway.

So those are all things that I think either you do have jurisdiction that you can exercise, or you certainly have influence that you can exercise in coordinating with other agencies to address those problems and from our perspective, from Vistra's perspective, that is vital, especially going into a future of potentially more of these types of extreme events, so thanks for the question.

MR. WHITMAN: Thank you. Before we go to Commissioner Christie, David do you have a response?

DR. PATTON: Yeah sure. I think it's a great question. I think I agree with Amanda that the participants that face market incentives if you price shortages efficiently, and as I said earlier that's probably not the case in most RTOs, but I think you'll get the responses from those entities that you're looking for.

I think the only -- I certainly don't think what happened in ERCOT was an indictment of the market there. I think it's difficult when an event is that far out on the tail of the probability to plan for it, or to respond to it. So I think there were some companies that didn't adequately prepare for that sort of outcome.

I think we saw a much bigger problem with public entities than we did with either the competitive retail loads, or the competitive generators. But so I would say rely to the maximum extent on market incentives, then identify the entities that don't have good market incentives. So I mentioned transmission owners a minute ago as being a set of participants you should be concerned about.

Gas pipelines are another set of participants that you should be concerned about. I think in almost all cases gas shortages are not shortages of supply, they're shortages of pipeline capacity, delivery capacity to certain areas, or the inability to fully utilize the capacity. And so that's why some form of improved coordination in how gas is scheduled and delivered would be extraordinarily valuable, whether it's a gas RTO model.

I know there would be tons of pushback because when the gas pipeline system is not constrained it would be hard for pipelines to charge much for delivering gas. But it is the one way that you would be able to ensure that you're maximizing the throughput of the pipeline, and minimizing the sort of fuel supply problems that Amanda was talking about.

MR. WHITMAN: Thank you. Getting close to the time, can we go to Commissioner Christie?

COMMISSIONER CHRISTIE: Sure. Dr. Patton I'd like to ask you to follow-up a little bit and expand on you said FERC should require RTOs to have seams agreements, and the seams agreement should cover several topics. And I got down congestion and more efficient management imports and exports. Would you elaborate on I think you have some other criteria that you thought should be in the seams agreements?

DR. PATTON: Actually those are the two biggest because they govern two things. One is coordinating the power flows where you have two neighboring entities that are causing flows on each other's constraints, and then the second is the broader movement of power from one region to another, which may or may not.

They can sort of cross over because when you get a lot of imports that could cause constraints that you're going to have to work together to manage, so they're not completely independent of one another. But the only other thing I had mentioned was like if the power is coming from a non-market area like the southeast for instance, if they hit a constraint in the southeast then that power won't be able to flow and actually make it to out let's say MISO.

So some form of required redispatch for non-RTO areas would be a third thing that would be extremely valuable. So that's not as much about coordinating, but it's more about facilitating participant's ability to get power out of the non-market RTO area.

When somebody schedules at a PJM or MISO, like MISO and PJM will just naturally move the generators they need to move for the power to escape their system. That pertains with non-market areas.

COMMISSIONER CHRISTIE: Thank you.

DR. PATTON: Uh-huh.

MR. WHITMAN: Thank you Commissioner Christie. We're going to go on to just because we have just a couple minutes to briefly talk about question 5.

MS. TOPPING: What best practices exist in the use of innovative mitigation strategies such as controlled sectionalization, microgrids in operations to reduce loss of load and improve resilience during extreme weather events? And let's see. I see Anne's hand up. Let's go to Anne and then Mads.

MS. HOSKINS: Terrific. Thank you and thanks again. I know we're about to close out here. So we do have some developments that I think are really critical and very much related to the potential for microgrids going forward.

You know in our view having a solar battery on someone's house is essentially creating what you might consider a nano grid right? And as we get greater electrification, this is going to really increase both the need for that source of power, that really local source of power, but also the potential as we're able to start connecting these together, as we're starting to see you know the multigrade chargers, other kind of electrification in the home.

So we sort of look at that as the sort of individual nano grid. But then what we're able to do as I mentioned earlier is to connect those in the form of virtual power plants. And we have about 12 of those already in the works around the country with many more in the pipeline to come.

Where we are working with utilities you know who are making you know billions of dollars a year in upgrades and investments in the distribution system to be a part of that right? To be a solution where you might be able to use a virtual power plant instead of you know developing new plant, or in preparation for closing one down.

And so I think that development where I know other providers are also getting more engaged in that is something to keep an eye out for. And then the other interesting kind of approach which it's really much more in early developing, but I think is really critical to be able to work with, with utilities, is this idea of a neighborhood grid.

And you know I heard I think it was Mads earlier talk a little bit about transactive energy and some of those ideas, but really what the idea here would be is you have you know a subset of the homes and businesses in a neighborhood which could actually be fully disconnected from the grid you know, linked to a substation where you would be able to disconnect, not just at the home which we're able to do now in this nano grid, but actually to disconnect a segment of the grid.

And that's something that we haven't tried yet, but we are working on it I think is an opportunity for any state commissions that are listening to think about some of the restrictions that get in the way of that where we're restricted to be able to you know have power over different geographies. But also potentially for FERC as well you know, as we get into some of these larger reliability issues.

So in my view it's a really exciting opportunity that we have now to really start to rethink as we're trying to create a more resilient and reliable grid of how we can really aggregate the investments and the resources that people and businesses are putting on the network, thanks.

MR. WHITMAN: Thank you. We'll have Mads next, and close out with Wes. Mads?

MR. ALMASSALKHI: Thank you Peter. And thank you Anne for raising really good points around DERs. We are ourselves a very small company, but I think when we go back in Texas we saw some of the practices in place around the rolling blackouts of how to manage certain extreme events.

If we were to pursue intelligent electrification as an infrastructure, I think what we'll see is that these rolling blackouts could not exist anymore because we could manage electric demand in an intelligent manner and therefore avoid, or smooth out what appear like rolling outages, but are really just flexible demand at work.

And so with Packetized energy what we've been able to and lucky enough to work with is Stanford National Lab, and there it's shown that really through you know advanced control mechanisms, we've been able to prioritize high-priority loads during these extreme events, and how to ensure the hospitals and schools for example, are prioritized over certain residential demand side loads.

And when you do that at scale, or at the size of part of the city you can really help ensure that part of society, the backbone of society is really able to function as well as possible during these extreme events. And just one other brief comment to make is that we've talked about DERs.

NERC has been really flexible recently in thinking about DERs beyond solar and batteries. And really thinking about demand side loads as also being aggregated and being part of distributed energy resources, which we think that Packetized is a really important step forward and we look forward to seeing that DERs taking a more inclusive term, beyond just batteries and solar. Thank you Peter.

MR. WHITMAN: Thank you. Maybe we can have Wes pretty much close us out.

MS. YEOMANS: Yeah. I think I'm into your break now, but I'll talk fast. So I do agree with what Mads and Anne just talked about. I'll take it up a level as a high voltage transmission operator. Since the 2003 blackout, and really the tremendous development of additional PM new phaser measurement internet technologies, we have spent a lot of time looking at controlled subsidization at the transmission level.

So I'm moving this up to a higher voltage transmission, and first of all controlled sectionalization can mean a lot of things. But anyway we do the math, New York -- and I'm just speaking about New York, we are far more stable, well connected with transmission lines rather than trying to mitigate an event by disconnecting or opening transmission.

We receive a lot of stability by being connected to the eastern interconnection. Having said that, we really think the opportunities are to the extent that we can use PN, or if we think there's extreme weather coming and our neighbors are having disturbances, or extreme weather, there's actually a tremendous amount of benefit again to re-dispatching the electric system to back down the power pole, similar to what we do with thunderstorm alert.

And then if you're operating to 99 percent of a voltage collapse or a stability limit, and then you had extreme weather or contingencies, you're in kind of a bad spot. If you're going to redispatch and get your actual flows maybe down to 60 percent of limit, now you have a lot of headroom for disturbances and flow. So I just wanted to offer that at a higher voltage. Thank you.

MR. WHITMAN: Thank you. I think we've reached the end of our time, Elizabeth?

MS. TOPPING: Sure. So I'd like to conclude by thanking our panelists again. We appreciate you taking the time to speak this afternoon and all the insight and feedback you've provided. We will now take a 20 minute break and reconvene at 3:20.

Panel 3 panelists you may sign out of the Webex meeting. If you'd like to continue watching the conference you can use the public webcast link on the conference event page at FERC.gov. Panel 4 panelists please stay with us over the break. Commissioners stay signed in and when you go on the break please mute your microphone and turn off your camera until we resume. Thank you everyone and see you in about 18 minutes.

(Break.)

Panel 4: Recovery and Restoration

MR. AMERKHAIL: All right welcome back everyone. Let's get started with our fourth panel today entitled, "Recovery and Restoration." I'll turn it over to my moderators, thank you.

MR. HENSLEY: Thanks Rahim. I'm Jesse Hensley from the Office of Energy Policy and Innovation. And with me I have Pat Shob also from the Office of Energy Policy and Innovation and we'll be serving as co-moderators. As Rahim mentioned this panel will focus on the recovery period following an extreme weather event, including but not limited to topics such as restoration practices and prioritization, mutual assistance agreements, spare parts inventory and sharing.

Six panelists and six questions. We're going to forego opening remarks and move directly into a question and answer session. I'd like to start by introducing our panelists. We have Kevin Geraghty, Chief Safety Officer and Senior Vice President Electric Operations from San Diego Gas and Electric;

Daniel Brooks, Vice President of Integrated Grid and Energy Systems; and Charles Long, Vice President of Transmission Planning and Strategy, at Entergy; Michael Bryson, Senior Vice President of Operations at PJM, Brian Slocum, Vice President of Operations from ITC Holdings, and

Jodi Moskowitz, Deputy General Counsel and RTO Strategy Officer at PSEG.

Thank you to all the panelists for being here this afternoon. I really appreciate it. I want to remind everyone to refrain from any discussion of pending contested proceedings. We also have our lawyer, Michael Haddad on the line, and he's going to throw the flag if we get into any contested proceedings that might raise ex parte issues.

So we're now going to go right into the question and answer session. If you'd like to answer a question, sorry, please use the Webex raise hand function. And if you're having any issues with the raise hand function please just turn on your microphone and indicate that you'd like to respond. I will call on anyone that indicates that they want to respond.

Like I said maybe not every panelist will respond to every questions, with only an hour, but we'll do our best. So when you have completed your answer please turn off your microphone, and if you used the raised hand function please lower your hand. Okay with that I'm going to jump right into question one and I think by virtue of who emailed me first, I'll start with Jodi Moskowitz.

And question one is what are best practices for restoration, including for determining appropriate prioritization of load restoration, mutual assistance agreements, and spare parts inventory and sharing? And then how should these best practices evolve given the increasing frequency of extreme weather? So Jodi all yours.

MS. MOSKOWITZ: Sure. Okay. Good afternoon everyone. Thanks Jesse and I want to thank FERC for including me and inviting me to participate in this conference today. I think I'll start by saying that New Jersey has become a poster child for extreme weather and the impacts of climate change.

Over the past 11 years PSEG has seen the worst storms in its almost 120 year history. Some of these storms include going back to March 2010. We had a nor'easter where we lost about 450,000 customers. Then the following year August 2011 we had Hurricane Irene hit. Two months after that we had a record breaking wet snowstorm which caused extensive damage to our system and to our customers.

A year after that, October 2012, we experienced super storm Sandy and at the height of that storm we lost about 1.8 million customers over 90 percent of our customer base lost power. We had 110 of our substations that were impacted, and 51 of our transmission lines were impacted.

And then I'll fast-forward until August of last year, August of 2020 where Tropical Storm Isaias hit our service territory. We lost about 575,000 customers in that storm. It was a very quick-moving powerful storm, however within 72 hours 98 percent of our customers had been restored.

So when we look back over those 10 to 11 years we learned significant lessons, and I wanted to kind of share a few of those lessons with you. I think I would sort of bucket those lessons into four, three potentially, four categories.

The first is the need to invest in infrastructure. You know so that's not so much what do we do in the restoration process, but what have we done to harden our facilities, make them more resilient so that we are reducing the frequency and duration of outages.

And from PSE&G's vantage point over the last several years we've made significant investments in our infrastructure. We have put in service several large backbone projects. We've constructed over the past decade, particularly in the year since super storm Sandy, and in Isaias those facilities held up extremely well.

We actually had only four momentary outages on our bulk transmission system which occurred due to fly in to break. And we had no extended customer outages on our transmission facilities. Similarly, for our 69 kv sub-transmission we've actually made investments to convert our old, less resilient 2600 kv system to a 69 kv system where we have newer poles, stronger poles, stronger circuits.

And as a result all of our 69 kv facilities that were impacted in Isaias were restored in day one of the storm. We've hardened and raised our substations. We've actually worked again in 2014 and we raised 32 of our substations, so they're all at FEMA level plus one foot, and as a result we did not have flooding in those sub-stations as we've had in previous storms.

We've also upgraded our state systems, our station relays so we can remotely operate our system, so workers can get in and safety do what they need to do to restore the system. So that's kind of the first category is actually making the investments I the system so that we don't have these lengthy outages.

Second category would be the mutual aid front. And you know we found that proactively reaching out to mutual aid crews, making sure that we have all of our critical materials in place prior to the storm is very important. PSE&G actually participates in the North Atlantic mutual assistance group, which is a way for us to get mutual aid quickly from utilities that run from the Mid-Atlantic region up to Canada.

We also use a tool called ramp up, which enables us to get mutual aid quickly from even outside that region, so we put that in place. That's been helpful. And then third major buck will be communication. And I think that all utilities have seen this over the past decade. The need to how to put in place a multi-dimensional communication and stakeholder engagement plan.

So we have daily media advisory updates during storms now. We have daily calls with our local, state and federal officials. We have liaisons to our local offices of energy management. We proactively reach out to our life support customers, so all of that is very important and enables us to kind of get a pulse of what's going on in our system which you know leads to helps us in our restoration efforts.

I think the other thing that I would just mention -- I'm assuming that Mike from PJM is also going to hit this, but we work closely with PJM in business continuity planning. PJM holds yearly restoration drills which we participate in. We participate in NERC grid-X exercises, which is not so much on severe weather, but more in making sure that we're prepared for cyber and physical security attacks.

So all of that in terms of preparation -- prior preparation, helps us in our storm, in our restoration efforts.

MR. HENSLEY: Thank you for that response. That's a perfect segue because the next hand to go up was

Michael Bryson.

MR. BRYSON: Thanks Jesse and again thanks for the invite on the panel. I think I just want to make two points really briefly to kind of complement what Jodi talked about. One is this concept that black start, and you know kind of storm restoration are really two different concepts, but use a lot of the same things. And we're going to talk about black start in a little bit more.

But that black start system restoration when I think about PSEG in New Jersey the past couple of years and Charles might talk about with Entergy. They've done a lot of extreme event restoration of customers, but I know in PJM we haven't fired up a black start unit because we needed it in 25 years.

I mean so it's kind of a different concept, but that idea that you're going to use some of these spare parts and mutual aid really kind of reinforces the need in both of those. The second one is this idea that you know when I think about PJM has over 150 black start units on our system, and from a best practice perspective I would take one tie line with an outside system over any black start units in my system.

And they're great, but we really having an interconnective system with MISO in New York and Va-Car and TBA, I mean that's really what we're going to lean on in terms of trying to restore the system, and so those are kind of two best practices making sure you're tightly coordinated with your neighbors.

MR. HENSLEY: Thank you. The next hand I saw up was Brian Slocum.

MR. SLOCUM: Yeah thanks, and thanks for the invite today. Other than the fact that I feel like you got invited to this because you withstood some sort of event on your system for the last 12 months other than the COVID situation we've gone through. But I'm happy to be here today.

For us it was last August. We had devasting Derecho that moved across our transmission system in Iowa. And I know Charles has got me beat as far as if we're comparing who went through the most last year as far as severe weather in Louisiana there, but our damage was likened to that.

We called it a 40 mile wide tornado that was on the ground for a 200 mile stretch. And another way we talked about it was having a category four hurricane hit the corn fields of the Midwest. Just a crazy event for us, and I think it really brings home the point that we're talking about here in this conference, or in this technical conference here where these extreme events seem to be kept happening more often, and then also hitting areas in ways that we've never really seen before.

Adam Smith talked about it yesterday too. We had 11 billion dollars in damages that were caused not only in our service territory, but our partners in the area as well were part of that damage. And so we certainly learned a lot from that and other events that we've had in the past.

I'd say the good thing is that us as a utility industry, I think we're really good at this restoration process and all the things that were mentioned Jesse in the question that you have there. Restoring load as quickly as possible, working together with those mutual assistance agreement, I'll focus on the inventory for us.

I think we had two primary lessons learned regarding inventory through our experience in the storm in the Derecho. First was standardization which is something that we've been working on as we've grown from an independent transmission company in just Michigan, and widening our footprint to include Midwest and down in Kansas and Oklahoma as well.

Is making sure we had that standardization so that we can help ourselves out from our other adjacent service territories, and that's exactly what we had to do is take inventory that we had in Michigan, as well as resources from Michigan, and help out there in Iowa. And so I think the other thing is on the supply chain side, we're trying to effectively manage our inventory to make sure that we're able to respond to events like this, but also balance the cost of that inventory.

And so I think that's something for FERC to keep in mind is you know that's part of what we need to do to run our operations is to keep an inventory. We also went through an analysis back a couple years ago to plan for just this type of resiliency type event where we would come up with storm equipment, storm inventory to make sure that we had what we needed to respond to an event based on what we thought that impact would look like on our system.

And so that helped us to prepare for the events. And so you know I think another thing is just working together with our partners that we have in our supply chain. We have a lot of agreements with them where we can call upon them. I'd say the only thing you know as far as how do we need to evolve these practices, I think what we've learned more recently is we have agreements, as I'm sure many other entities have agreements as well.

And if we have a more widespread event, we're all going to be picking up the phone calling similar partners. And that's where I think we might need to work on figuring out well how do we figure out those priorities in response, which also goes to prioritization of the load restoration as well.

I'll stop there just to give Charles a chance to one up me with his experiences down in Louisiana, so thanks Jesse.

MR. HENSLEY: Thank you. With that I'm trying to go in order. I will turn to Kevin Geraghty next please.

MR. GERAGHTY: Yeah thank you Jesse. I'll just try to differentiate a little bit, but echo a few of the other comments that I heard. First at San Diego Gas and Electric a little bit different situation for us. We operate in a very extreme high fire threat environment.

Our high fire threat district space is extreme and growing risks really into wildfires here in California. And we can impact our communities by either A -- being a source of that ignition, causing a major wildfire, so we focus on preventing those, but then also our systems can be impacted by those wildfires.

So we are operating at an elevated fire risk, and/or hardening our system year round. And at times that risk is so high that we just cannot risk our assets becoming an emission risk, and we'll actually de-energize portions of our system for safety. And these are called power safety -- or public safety power shutoffs or PSPS.

And while we look to do that as a last resort, we do look to restore those customers as quickly as possible, and I think we've got some best practices that kind of help with that. And I think about it really being three things. And a few you've heard about. Now alter the assets to meet the new challenge they face. You can't wait for retirement. Can't wait for end of life.

If your assets can't operate within the increased threat environment we need to replace them, rebuild them now. You have to have the greatest of situational awareness possible, and that is moving from just broad awareness of your system to really granular awareness.

And the one that I would also point to is you have to have world class emergency operations and community engagement. When I think about what differentiates STG&E quite a bit. We have a first of its kind utility meteorological system, so we have more than 20, 220 weather stations across our high fire threat district that provides 24/7 real time information on the surroundings our assets are operating in.

And because what we have learned is that a general weather model is not good enough. Our Santa Ana winds can vary incredibly to where a region may see completely different conditions, or a town may see different conditions within the length of one circuit. We have a staff of meteorologists, and we couple those with those weather stations, 100 cameras and satellites to always be assessing our current fuel conditions our wildfire weather and then spot fires quickly.

All of that is really coordinated through our emergency operations center. We work intensely with our community stakeholders via the internet command structure. It's a passion here at STG&E.

We make all of our resources available to our community, so we have two firefighting helicopters, other patrol helicopters that we make available to our communities because it really just doesn't matter whether we're the ignition source, a fire anywhere in our community impacts our community, impacts their resiliency.

And so we train and drill thoroughly with our first responders all year round. And as part of a unique thing that we are faced with that we have to work with, we work in this high fire threat all the time. We have to you know modify our system, improve our system every year.

And so you will find our crews are out working in the high fire threat district to actually have contract fire resources right with them. Because we can't run the risk that our work actually becomes part of the ignition. And I would just emphasize what I think I heard in the other responses.

This risk is growing. It's evolving. The investment is required. We put already 322 billion into fire risk mitigations since 2007, but the results pay off.

Our communities are more resilient, and safe and reliable today, and we just have to continue to have the kind of priorities and investment that really address this growing threat, and thank you.

MR. HENSLEY: Yeah thank you. We've gone from New Jersey to California. I think now, and I'd like to come back to Louisiana. Charles Long would you like to speak to question one?

MR. LONG: Sure. I too appreciate the invite, and the discussion, and I certainly agree with a lot of what's been said already. And we don't corner the market in Entergy on extreme weather, but we certainly do get our fair share, especially along the Gulf Coast in Louisiana and Texas.

But we have been doing this a long time, and we've done restorations -- major restorations for a long time, and I do think we have some best practices that you know that the industry can adopt. And for one of them we do a lot of planning in advance. If you wait until you're threatened to start the planning, it's too late.

A lot of processes and questions can be predetermined through those plans so that you're not having to make those decisions in the heat of the bottle. Things like prioritization for example, just with broad strokes of prioritization can largely be done in advance.

We too reorganize into a dedicated response organization, an incident command structure that's singularly focused on the restoration, so I think that's really important. Prioritization is also really important and the way we've learned to do that is just to bring in -- we have representatives for all of our customers, government liaisons, you know all of the stakeholders that would be interested in restoration are in the room and help with the prioritization.

It just works better to have that stakeholder process right there in the command center. As far as how things would evolve, or should evolve as things continue to I think get more challenging. I think I would encourage people to drill, and drill on more extreme scenarios that maybe you faced in the past, so that you can always practice them hard and making the games easy.

And then the other thing I would say is it's prioritization is going to have to evolve a lot. I mean think about how many dependencies are growing with the electricity sector. You just have to be able to prioritize based on more than just the electric service. There are all kinds of other services that should factor into how you prioritize.

If getting the lights on isn't the top, isn't going to solve the problem, then maybe that's not the top priority. But if you think about how things are going to change in the future, transportation, information, communication, all of those infrastructure sectors are just going to be increasingly dependent on electricity.

And if you think about an electric vehicle world where evacuations are dependent on being able to charge your electric vehicles on the way out of town, there's just new aspects of how we should think about prioritization and how we should develop systems in the future as those other infrastructures evolve.

MR. HENSLEY: Okay thank you sir. I think the last hand I saw for question one was Daniel Brooks.

MR. BROOKS: Yeah thanks Jesse. And the short answer to that question which of these things don't belong. So we've heard from five utility staff, so like as staff and the consultants when you're going through an actual restoration process, so I won't get into the best practices.

These guys and ladies have covered that well. I'll talk about the research that we do in many of these organizations that are here, utilities as well as others throughout the country and the world to look at what emerging capabilities and processes and tools may be helpful as we go forward.

And obviously, doing work to look at how you minimize power to repair the physical damage to the system and I'll save that for the next question that's more focused on that. But looking at how you actually minimize the time to electrically restore service as we get into prioritizing those critical loads, all of those different things.

I'll offer just a couple comments. One around black starts. Michael said you would much rather energize a system from you know still ties to other systems if you have the option to do that, but should you need, God forbid if it ever comes that we have to actually black start from a completely dark system, you know, you want to make sure that you have the capability to determine the optimal number, location and capacity of those black start resources to minimize the restoration time.

And that changes over time as the system changes right? And with all the changes that we see going on with you now units are tied, new units, new technology is coming in. How does that black start optimal change as you go forward? I think that's critical that you have the tools and capabilities to be able to optimally make those decisions.

We've certainly been working with a lot of the utilities and RTO/ISOs on over the last few years and have tools that are being used for that capability. Once you have those black start units, how do you then not determine necessarily the load priorities, but how do you make sure that you are optimally cranking through sequences that get to minimum restoration times for those priority loads?

As you start to establish that supply and delivery backbone, and the critical modes being energized as you go along from that, how do you make those decisions of what's the next best cranking sequence, the next best optimization path you could get to as you're going up multi-hours that you would then think across the system. You know it's all said, you have a plan to do that, and those plans are very useful.

But you also have to have tools that will allow you to adjust those plans in real time. You don't physically hear Mike Tyson quoting one of these types of conferences. You know Mike Tyson was -- everybody has a plan until you get punched in the mouth.

These types of significant high impact load frequency events, they create operating scenarios that aren't necessary what we expected when we were actually going through our training exercises right? Having tools that allow you to optimally adjust and figure out more.

These facilities are out, these black start maybe it's not available. These non-black start units aren't available. Now given my priorities what's the next best sequence to hit the critical loads established, and the backbone established? Have the ability to do that maybe something that's really important.

And the last thing I'll mention is being able to leverage and utilize emerging resources, distributed energy resources, even all system connected renewables. I know when you think about restoration processes the operators that are on the panel and others that are listening say hey, you get those guys offline, and you keep them offline until you can get things established.

But there are capabilities that those resources have you know, DR, there's an opportunity to have community resilience that's already been mentioned. There's even the opportunity to actually plan for and have critical loads that are served and energized and kept up from pre-determined plans of how you would actually the system to a question we'll have later and be able to keep those loads up.

You know from bulk system connected renewables, there's a lot of renewable capability that's available for those plants that you could take advantage of that may be very helpful in the restoration process. And potentially even from active power support if you have a high certainty based on forecasting, what you can do is that.

So that capability and understanding how to leverage those emerging resources into the restoration plans I think would be very important as we go forward and as our resource mix changes. And I'll stop there. I have some other things on mutual assistance that maybe we'll get to later if there's opportunity.

MR. HENSLEY: Okay thank you. Yeah I think you've successfully worked in our first Mike Tyson quote so, of the whole tech conference. It think all six of you have had a chance to respond to question one, so we're going to move on to question two now in the interest of time.

And question two is how can asset management practices and facility design requirements be leveraged to reduce restoration times following a severe weather event? I think we touched on this a little bit, but I'll look for hands. I think I saw Kevin Geraghty please go ahead.

MR. GERAGHTY: Thank you Jesse. You know when I thought about this question you know first of all I think that we're recognizing STG&E is one of the best mitigations for this, but the threats we face are incredible.

And you can't remove all threats instantaneously. So we used very intense risk informed models to prioritize our strategies, whether that's traditional hardening, whether that's covered conductor, or strategic undergrounding. And we're just trying to assure ourselves that wherever we place that investment that we're addressing the greatest chance of ignition, and also creating the greatest impacts on reliability and resiliency for the communities.

Additionally, when I think about those things you can't yet replace, the State of California has established minimum patrol and inspection programs at the CPUC, enforced its compliance with on a continuing basis. And STG&E would go far above and beyond those requirements. We patrol all of our high fire threat districts before and after any one of these fire weather events.

We use drones to get incredibly detailed assessments, and that information, all that data, the video, et cetera is available to someone like me during an emergency operation that's got to make a decision on whether or not to de-energize. But as we move forward we're really much more intensely into knowing real time condition assessments, and so we're looking very intensely at parcel discharge to actually determine segments of lines that were failing long before they actually have a failure, and we're also looking at falling conductors as one of those ways to actually de-energize our system long before it causes a problem.

But I will tell you way above and beyond the obvious assets whether it's the structures and the wires, there's so much more to gathering this data, whether it's weather data, camera data, condition data, the satellite information, and we're actually building our own private network to bring all of that data back to our teams to be able to make informed decisions because it's no longer about skating, know the condition and operations of your system, you have to have complete awareness of the environment that it's operating in.

And I can't stress enough the importance of education management, and obviously that would apply across the board. I think utilities whether you're facing storms back east, or fires here, the vegetation management, fuel mitigation efforts are key, and the science and data around that is getting to be incredible between cameras, satellite centers and other really risk informed models that allow us as a utility to get to the most critical thing now.

And so as we think of evolving into you know fire safe 4.0 we call it, it's much more about getting even more real time data and more condition-based data of the assets.

MR. HENSLEY: Okay thank you. I just want to note we're already halfway through our hour, it's hard to believe. I'll just ask everyone if you can keep your responses as tight as possible. I hope to combine questions three and six because they kind of both touch on dual fuel. But the next hand I saw I believe was Ms. Moskowitz. Could you please go ahead. Sorry Jodi did you want to respond to question 2?

MS. MOSKOWITZ: It would help if I took myself off of mute. Okay. Here I am. I wanted to just kind of quickly double back to a point that I touched on in response to question one as it pertains to how we're designing our substations. And I mentioned the extreme flooding conditions that we found ourselves in during super storm Sandy.

So what we did beginning in 2013 was to design and implement a wide-scale transmission hardening program that basically leverage FEMA flood elevation data, and incorporated them into our facility design requirements. So we were raising -- we raised our stations in flood prone areas one foot above the FEMA flood levels, and incorporated our designs to shield our equipment from the damaging effects of wind and debris.

And that has really paid dividends for us. We've determined that if another storm as powerful as super storm Sandy were to hit us again, we would lose about 500,000 fewer of our customers, and those who did lose power would be restored more quickly. We've also seen we had a significant tropical storm in May 2018, one of our substations that was impacted by Sandy we had raised that.

And if we had not raised it, we have 5,700 customers directly connected to that substation and all of those customers would have lost power and none of them did because of the way that we hardened the substation. So I want to give that as an example of how we sort of proactively incorporated these flood, FEMA design requirements into our stations and that has reaped benefits for our customers.

MR. HENSLEY: If I could just really quick respond, was FEMA plus one a voluntary effort, was it part of your company?

MS. MOSKOWITZ: Yes, yes.

MR. HENSLEY: Okay.

MS. MOSKOWITZ: It was.

MR. HENSLEY: Thank you. Thank you for that response. The next I saw was I believe Charles Long from Entergy.

MR. LONG: Yeah just a couple things and I'll try to be quick. I think from an AM, an asset management perspective one of the things that I think is really valuable is to make sure that when you're doing inspections that you don't just inspect the equipment, you also inspect things like drainage, and erosion control, and heaters. And some of the things that can lead to you know failures that are really not related to the equipment.

Another thing is to make sure you have pre-determined evacuation plans for employees, equipment and materials that are going to be critical to the restoration. You know having your employees or equipment impacted by the events such that they can't engage in the restoration is obviously not somewhere you want to be, so pre-plan that, so you know where you're going to evacuate those people and materials to.

On the design side you definitely need to continue to look at criteria and standards that reflect the weather such that we see. Increasing the wind loading design, ice loading design can obviously pay dividends. Someone mentioned elevating critical substation equipment that can be very, very effective Flooding can actually be one of the longest to recover from. It's worse than wind in many ways, but it just take a long time, it's very intricate work to recover a control house.

Geographic diversity you know think about how you can get power into the area from multiple locations, fuel diversity for generation I think is another thing. We talked about it later in black start and I'll talk more about it, but yeah I think that's also a very helpful thing to have multiple fuel type scenarios that are going to be impacted.

And then Mr. Bryson talked about the value of that one tie on and I completely agree. The first lights that were on at Lake Charles after Laura were actually lit from a tie line. They weren't lit from a black start generator. And even for Laura where we saw winds on the coast of Louisiana at 150 miles an hour, our newest designs and transmission lines didn't survive.

So they were undamaged, and it was you know part of the first things restored in the Lake Charles area, so those higher designs and new criteria do pay dividends and you should continue to evaluate those with evolving weather threats.

MR. HENSLEY: Thank you. Brian Slocum I saw your hand up next.

MR. SLOCUM: Yeah just quickly, I'll piggyback off of what Kevin was talking about vegetation management. His issues in California are different than mine in the Midwest, but I would just offer up you know we have stick in place right now with FAC003 with respect to vegetation management.

Perhaps there's a carrot that can be put out there with respect to sustainable vegetation management programs and practices that utilities will put in place that FERC could look at and incentivize, whether that's allowing capitalization of certain activities, or providing incentives around that.

So you have both the carrot and the stick with respect to vegetation management issues. So I'll put that on the table for consideration. And I think it's interesting that a lot of what we're talking about here, you're hearing things that are above and beyond. You know

Jesse asked a question, was that voluntary that you did that.

And I think there's a lot of things here that are unique to the service territory, unique to the conditions that each of us are operating in where we are going above and beyond what the minimum design requirements are. And that's sort of contrary to other things that we're talking about within the industry with respect to competition and getting the lowest cost.

And so there are competing priorities here and I'm just really glad we're talking about this as an operator today because for me operating the system it's really important that we have the ability to go above and beyond and to make sure that we have designs in our system that can withstand the type of weather that we are seeing, frankly.

MR. HENSLEY: Yeah thank you. I think that's a really important point. I'd be remiss if I didn't ask I think we have a couple of Commissioners at least on the line, if Commissioners have any questions they'd like to weigh in with.

CHAIRMAN GLICK: Jesse I understand that you're asking, but I don't have any questions. But I wanted to tell you that I want to thank all the panelists for participating today, very helpful.

MR. HENSLEY: Thank you Mr. Chairman. I think in the interest of complements I think there's a lot of interest in three and six, I'm going to turn to those. Question three is should restoration capabilities be improved by encouraging planners, governmental authorities and utilities to require dual fuel capability in all black start units?

And if you can find a way to maybe double up and work in some question which is about cost recovery concerns, or regulatory barriers to the implementation of practices that would ensure the timeliness of system restoration, that also gets into the maintenance of the dual seam capability of black start units.

And just personally I'll say there was a Wall Street Journal article about black start on the cover of the paper a few days ago that I thought was quite interesting related to black start. And it's not often that you see black start on the cover of the Wall Street Journal.

So who would like to go first here? I see Charles Long I see your hand up. please go ahead.

MR. LONG: Yeah I think black start is an interesting topic and I really think you should think about fuel and generation just much more broadly than black start. Certainly, fuel diversity is valuable in any kind of event. Dual fuel, or even if it's not a single unit with dual fuel, dual fuel in an area that might be impacted can be very valuable.

And so I think you should really think about that, in a system planning aspect where you know maybe if you have a gas generator next to a nuclear generator, next to a solar generator, you know those types of things, energy proximity can be just as valuable as dual fuel.

And then I think you know black start is certainly critical and if we ever you know knock on wood, have a large eastern interconnection type event we're going to have to have those. But I think it's important to realize that most of these extreme weather events it's really transmission restoration that gets the ball rolling.

So I think there are ways to think about it more broadly. I think you can also do some analysis in advance about what areas at least will be key to the restoration after an event. You can do some of those analyses in advance and get a feel for that.

And I think there are some other things that can be done, you know, besides just dual fuel, just to help with the restoration over all there are just many more effective, and with hardening transmission and distribution can certainly pay a lot of dividends.

Fuel delivery infrastructure can be improved probably you know more efficiently in some cases to where the infrastructure to deliver the fuel is just more reliable. And then one of the things that we found to be very, very valuable is onsite fuel storage.

And so if you know you can get some natural gas stored at the generator location that independent of pipelines or other infrastructure they you know you've got a lot available to you, and you can have several days of local fuel there that can get you started so that's my thoughts on black start.

MR. HENSLEY: Thank you very much for that. I believe I saw Michael Bryson up next. Again just weigh in, give me a holler if I miss anyone's hand up. Thank you.

MR. BRYSON: Thanks Jesse. And it's interesting you referenced the Wall Street Journal article. That was kind of a timely, I think that came out the day before our comments were due, but my wife who's way smarter than I am, had the opportunity to read the article and my testimony, and one of the comments that she made was boy, it seems like if there's ever something the federal government should help with it's this issue.

And I thought that that was kind of an interesting observation. We have an effort in PJM, and we're not calling it dual fuel, but we're calling it fuel security, so there's a lot of definitions. It's onsite fuel. It might be dual pipelines, you know, there's a couple different ways we define it.

But even given that loose definition of those 150 units I talked about, we have about 50 percent that I call fuel secure. The interesting thing is the hurdle to get to 100 percent fuel security is about 150 million dollars for the system. And the hurdle to get to just making sure every TO zone is fuel secure is about 20 million.

But having said that, jumping down to question six, the pushback that we got is you know it's such a low probability event, why do we need to make that investment? And so I think there needs to be some level of a minimum threshold you know from the regulatory perspective to help with that that might help with that hurtle, because when you hear the numbers we've been throwing around for the last few days in this technical conference, the dual fuel, or fuel security investments are pretty low numbers, thanks.

MR. HENSLEY: Yeah thank you. I think we both have wives it sounds like, that are far smarter than ourselves. With that I'll turn to Jodi Moskowitz, I think I saw your hand next.

MS. MOSKOWITZ: Yes. Just wanted to kind of echo the point about fuel security and fuel diversity in terms of emphasizing the need for example of having sufficient nuclear capability on the system. We all know that nuclear is a very secure fuel.

It is not subject to the same type of extreme cold weather variables as other types of generation, where gas supplies can freeze, or coal supplies can freeze, and it also has the benefits of promoting the clean energy future that we all want. But I did want to emphasize we're talking about resilience and fuel security, the important role, the critical role that nuclear is going to play going forward.

With respect to black start specifically I think one point I wanted to make was just the need for regulatory certainty in terms of compensation. That's an issue that we've been dealing with a little bit in PJM and making sure that you know there's an expectation that generators are going to offer black start service if there is certainty about how they're going to get paid in the same way that you know you often hear transmission owners you know being very concerned about fluctuations let's say in ROE policy et cetera, and the need for regulatory certainty.

The same would apply for black start. And I think the final point that I would make is I think we all need to think about what does the future of black start look like when we're talking about increased penetration of renewable resources. And you now where are the black start units going to come from, and what is that going to look like in 20 to 30 years, and something we should really start thinking about now.

MR. HENSLEY: Okay thank you. Kevin Geraghty I believe you're next.

MR. GERAGHTY: Yeah just real quick. I want to build upon Brian's comment earlier about the carrot for investment, and when I think about California last year it's well-known about the load curtailment right and that the supply issue. But in and around those days so many hours in August and early September there was so many transmission lines passed, impacted by wildfires that there are other equally precarious hours of that year -- that operating window.

And I could not emphasize more what's better is a very strong interconnected, reliable and resilient transmission system, and investing and reinvesting in that is incredibly important as we look to be the most reliable operators that we can be.

MR. HENSLEY: Thank you. I think with that I don't see anymore hands raised about questions three or six. I think I will turn to question four. We have about 15 minutes left here it looks like.

Question four is do the states and other stakeholders make decisions that impact restoration priority or techniques need to engage in greater coordination to establish a consistent means to determine restoration priorities. Anyone like to weigh in on that? I think Brian Slocum?

MR. SLOCUM: Yeah I can take a first stab at this. And my general thought process on this is that we do a good job of this. It was mentioned you know incident command structure in our Derecho experience. I mean we had somebody in the state emergency headquarters coordinating not only with the state, but also with our customers and we're transmission only.

So this is a little bit unique for us in that we're arm's lengths from those restoration priorities. So perhaps it's a lesson learned for others that are vertically integrated and maybe even for us it's a unique situation maybe a little more difficult.

And it shows where to Charles's point that he made, I think what we learned is we can do a better job of this up front. There's a lot of things that we are doing and figuring out within the eight day period where we were in restoration from the Derecho that we should be able to know that at a distribution level this transmission circuit that's out of service is impacting the City of Aims and their water supply.

And we should be able to highlight that red right on our sheet of outages right away without even having to get that input or phone call from that city. And so I would say that that was a lesson learned from us that the thing that we can do better is doing it more upfront.

And I think Charles made a very good point that as these loads change, we also need to make sure we're updating that viewpoint on those restoration priorities, and then we can save ourselves at least a little bit of trouble when we do get punched by Mike Tyson and we can figure out how exactly we want to respond and prioritize given the situation that's ahead.

MR. HENSLEY: Thank you. Kevin Geraghty please go ahead.

MR. GERAGHTY: Yes. Just building on Brian's comment that you know here in California because of the wildfire risk it is a continuing plan to check active better processes, and so monthly operational calls are held here with the California Office of Emergency Services, the CPUC, the Department of Forestry and Fire Protection, Cal Fire, every month regardless of the threats.

We also have monthly briefings with our fire chiefs. And I will tell you one of our most important ones when you think about the community, and whether the curtailments restorations is our quarterly collaborations with our local emergency managers, and our community leaders. We meet quarterly with over 40 stakeholders in our county to talk about you know their emphasis in what helps us determine where we may roll out micro grids to improve resiliency.

But I could not stress enough how critical it is to set up one of those advisory councils and just listen and make sure you're in tune with the county, the things that Brian mentioned up knowing before the community needs to tell you where there's a problem. You'll benefit from that rapidly and you can create quick GIS layers and whatever tools you're using such that you know the response and you know what the community's response is going to be, and you're going to know their priorities far better.

And then it leads to great solutions. Like we have a customer based app engaging with 2-1-1, the creation of community resource centers. But you can only get to there, if you intensely work on the collaborations with the community stakeholders, thank you.

MR. HENSLEY: Yes thank you. The last hand I see is from Charles Long. Please go ahead.

MR. LONG: Yeah I know we're running out of time I'll be really quick. I think just keep in mind the prioritization process is extraordinarily complicated. There are many, many aspects to it and optimizing that restoration prioritization is a very demanding activity, so make sure in your incident claims you resource that appropriately and give them tools and information they need to do that.

And then obviously, as it evolves, the

restoration priority evolves as you learn more information about damages and such that you just continuously changing, you know, so it takes a lot of effort.

And then the last thing I'd say is one of the things that I think to be helpful is you know more and more aerial imagery available, either from a satellite or other sources that are non-utility governmental agencies, the ability to quickly access that and integrate that into GIS systems could also be very helpful.

And I think the hardest part of prioritization is damage assessment. If you have a good damage assessment, you know, how long it's going to take and what type of resources it's going to take to restore all the facilities you can make a pretty good plan. If you don't know the damages in a very detailed way, it's very difficult to do a good prioritization, so I think that would help.

MR. HENSLEY: Thank you. That's a great point. I think I did see Michael Bryson if you would like to be the last one to weigh in on this question four, then we'll have 10 minutes left for our question five, thank you.

MR. BRYSON: Yeah thanks Jesse. Just really quick. You know Brian talked about that you know kind of getting feedback from stakeholders and education. I think managing that expectation with stakeholders and states up front is important, particularly because when you look again at that difference between a black start system restoration and an extreme weather event system restoration because those expectations are going to change, and so putting some time in the up front work is really important.

MR. HENSLEY: Thank you. Unless I missed anyone I think I'm going to turn to question five.

DR. BROOKS: Hey Jesse just one comment quickly.

MR. HENSLEY: Oh sure.

DR. BROOKS: A regulatory one, although not for the Commissioners here, more outside the AA, that situational awareness that Chuck was talking about that's really important for assessing damage and for prioritization you know, drones are obviously being used more and more for that. A lot of good work being done there. We've been working to help characterize the capabilities.

But the next day hurdle is getting regulatory ability to do beyond visual modified, to be able to increase the capabilities there. It's not something that the Commission here can help with, but it is something that would improve our ability to actually prioritize and have that situation awareness, probably worth mentioning.

MR. HENSLEY: Thank you. My apologies for missing your hand there. Last question is question five and it looks like we have about eight minutes to answer it. Question five is can innovative mitigation strategies such as controlled sectionalized or islanding employed during the operating day to improve resilience and reduce the loss of the load, also help to ensure more timely restoration of services to loads that are lost in an extreme weather event?

Give me one second. It looks like Brian Slocum I think is the first hand I see up.

MR. SLOCUM: All right finally I won the Family Feud contest. I hit the button first. I think the question I agree with yes, but my only issue is you know deployed during the operating day break, but it goes back to what we heard yesterday, and it has to be planned into the system such that it can be available for the operators to deploy, and/or for the people in the field to deploy.

I think back to a situation that we had in the Derecho where we had a very large transmission structure and on it were two feeds that both were down and basically impacted our ability to provide service to a town.

I'll leave their name out of it, but anyhow if we could have put into place and would have done this analysis you know a better way to feed a diverse path to bring to that town, then we could have relied upon that sectionalizing scheme to basically you know get that load restored more quickly.

The thing that we run into oftentimes when we take projects in through the RTL planning process is the TPL standards are seen as this is what you're to plan to. And when we bring a project that says we want to pull a line from a different location, a backup line for resiliency, or even in a routing.

If you want to route a transmission line in a diverse path that's not on the path of an existing transmission structure is already on. A lot of times we get shot down in that planning process because it's either more costly, or the permitting is more difficult and I think that's where we can be given some amount of help to make sure that these resilience issues in designing and planning the system can be considered, and should be considered when we're doing the design and planning of the system.

MR. HENSLEY: Thank you. I'll turn next to Charles Long please.

MR. LONG: Yeah I think Brian's words were spot on. You definitely have to have, it has to be predetermined and it has to be designed you know years in advance, and I think if you think about operating scenarios that you would have to plan to implement it would just be very, very complicated, complex to deliver.

Kind of a system that could sort of try to self-heal. But I do think there's a lot to be gained from just decreasing the dependencies that are on the system. You know, the geographic dependencies or same voltage, or you may have transformer dependencies.

I think there are lots of things you can do from a resiliency standpoint that even if it's not an automated system, your operators can take advantage of and dramatically quicken the restoration. And I think if you have part of the plan for an event like you do for hurricanes, you know you can do a lot of things just on the days leading up to that.

If you have planned out a design generators, or planned out transmission lines, or substation transformers, there can be a return to serve and you can certainly increase you know your resiliency, and just by doing those types of activities before the event, but that's without a preplanned system that's designed to take advantage of those capabilities, I think it would be really tough to do.

MR HENSLEY: Okay thank you. We have about four minutes left, and I see Daniel Brooks and Kevin Geraghty before we have to wrap it up, thank you.

DR. BROOKS: Yeah I'll make it quick. So I agree completely with Brian and Charles that it has to be planned. And it is complicated. But I do think there's a real opportunity and a need as we start to transition the grid and the resources on the grid through the decarbonization clean/energy transition. There's a real opportunity for us to be able to identify, maybe not large islands, but to be able to identify those critical loads.

It might be the best critical loads, whether it be the final critical loads that we could plan and we could operationally in real time based on what the actual event has happened and the operating condition. We could be able to operate islands that would be able to provide resiliency to those critical loads that we would need up to support getting the rest of the system up for the support of society and you know just people being able to live in the middle of some of those events.

So there's tools and capabilities that are being developed to do that that we should be looking at that are going to be demonstrated and tested.

MR. HENSLEY: Thank you I appreciate the speed there. Kevin Geraghty please go ahead.

MR. GERAGHTY: Yeah. Well not all that innovative, I can tell you when I think about a picture from last year we had the valley fire tear up a large part of San Diego County, in fact it impacted a bunch of our customers.

And when all that fire ravage was done to go out there and see the steel structures still standing, but then also seeing wood structures that had really great vegetation management at their base, also having avoided fire damage, you can make a restoration much quicker by the way the system is designed and the way you manage that asset, and especially veg management, thank you.

MR. HENSLEY: Thanks so much. I see Jodi Moskowitz please.

MS. MOSKOWITZ: Yes I'll be quick. I just wanted to double back on the comment that was just made about islanding. And islanding perhaps can work in certain circumstances. It's very complex, and I think we would view it as not a substitute for the macro investments that need to be made on the grid, and that we have made, and that we have seen customers have significantly benefited from.

So it may be a tool in the overall tool kit, but I don't want to lose sight of the fact that you know we have the reality, and you can hear it from the discussion on this panel of extreme weather occurring throughout the country. It manifests itself in different ways, but the need for resilience, the need for redundant supply for customers that require 24/7 energy and so we really need to focus on what are those macro type proactive investments?

Brian talked about planning, design, that is really critical going forward.

MR. HENSLEY: Thanks so much. I think we're close to our time limit. Anyone like to add a final word, otherwise we will probably end it here.

DR. BROOKS: I'll jump in Brian and just say that I agree completely with Jodi. And my comment wasn't intended to say that we need to be looking at how we can you know intentionally island an entire system during a restoration event. I think there's targeted opportunities to increase the resilience of critical loads even with the more macro investments that are required, and that was my comment.

MR. HENSLEY: Thanks again. At least on my clock I see that we're about at the 4:20. It seems like a good place to stop. I want to really thank all of the panel four people for participating today. We're going to take about a 20 minute break and then reconvene at 4:40 with panel five.

So thank you all again and have a good afternoon. Oh you can I think you're going to be logged out if you're a panelist and you can join the FERC webcast if you would like to continue watching the conference.

(Break.)

Panel 5: Coordination

MR. AMERKHAIL: Okay here we are. Welcome back everyone. Let's get started with our fifth and final panel entitled, "Coordination." I'll turn it over to our moderators, thank you.

MS. MOYER: Hi I'm Alyssa Moyer from the FERC Office of Energy Policy and Innovation, and along with my colleague Lodie White from the Office of Electric Reliability, I'll be your final moderator for the day.

This panel looks toward the role that coordination and cooperation across jurisdictions, including but not limited to coordination with retail regulators including states, municipalities and cooperatives utilities and other federal agencies could play in long-term planning, operations and their covered practices to address climate change and extreme weather events.

We will be foregoing opening comments and move directly to question and answer session. Following this panel we'll have closing remarks and adjourn the conference. I'd like to first start by introducing our final set of panelists. We have Karen Wayland, Chief Executive Officer at GridWise Alliance.

Randy Howard, General Manager of the Northern California Power Agency; Dan Scripps, Chair of the Michigan Public Service Commission, Letha Tawney, Commissioner, at the Oregon Public Utilities Commission; David Terry, Executive Director of the National Association of State Energy Officials.

Carolyn Barbash, Vice President of Transmission and Development of Policy for NV Energy; and Patricia Hoffman, Acting Assistant Secretary, Principal Deputy Assistant Secretary, Office of Electricity at the U.S. Department of Energy.

Welcome panelists. As we begin I'd like to remind you to refrain from any discussion of pending or contested proceedings. If anyone engages in these types of discussions my colleague, Michael Haddad from the Office of the General Counsel will interrupt to ask the speaker to avoid that topic.

MS. WHITE: Good afternoon panelists. Thanks for rejoining us. We'll now begin the question and answer session. If a panelist would like to answer a question please use the Webex raise hand function. Alternatively, if you're having issues with the raise hand function, please turn on your microphone and indicate that you'd like to respond.

I will call on panelists that indicate that they would like to answer in turn. Once I do so, please turn on your microphone and respond to the question. When you have completed your answer please turn off your microphone and lower your virtual hand in Webex. Let's get started.

The first question is should the Commission consider pursuing ongoing formal or informal means of coordination with retail regulators on matters related to climate change and extreme weather challenges addressed in this proceeding? If so, what should the goals be with this coordination? I'll just go down the list of panelists and you can just give an answer. First we'll start with Ms. Wayland.

MS. WAYLAND: Well thank you very much. I have long advocated that the administration set up a formal or informal body that brings together state regulators and federal regulators to come up with a whole suite of issues that are blurring jurisdictional lines between the state and federal authorities.

Both many of the things that could be tackled, we original came up with this recommendation in the first forward energy review, and in fact I worked very closely with FERC staff to develop a recommendation called "Coordinating Goals Across Jurisdictions." We were originally thinking that this would be about the kinds of blurring of jurisdictional lines that emergent technologies are creating, but actually, the multi-faced nature of climate and extreme weather makes it perfect for such a standing by.

MS. MEYER: Chair Scripps I see your hand up.

MR. SCRIPPS: Excellent. Yeah I totally agree as well and as FERC indicated in question 17 of the supplemental notice the Section 2.09 of the Federal Power Act provides a forum and a framework for this sort of state and federal cooperation, and I would say and partnership.

I'd also highlight in some of the myriads of comments that they submitted that this really sort of comes out of Congress's desire to acknowledge the dual roles that both the states and FERC have and as they noted there may not be a better example of issues that should be addressed by a multi-jurisdictional, multi-pronged collaborative approach than those related to climate change and extreme weather events that have an impact on local and general electric systems.

So I think this is well teed up for that sort of thing. I guess in structuring it I would focus -- I mean obviously this is a big topic right? It's climate change, it's extreme weather, it's electric system reliability. So focus on tangible opportunities, really drill down to where the rubber hits the road on things like forecasting and transmission and response.

The things that sort of you could come up with action plans around as opposed to just another forum for discussion. But something that leads to concrete action I think should be the goal. And I also think it's an opportunity to take advantage of state activities in this area.

In Michigan for example, in 2019 following the polar vortex you know it was ultimately a success story. The heat stayed on, the lights stayed on, but we were close. And our Governor, Gretchen Whitmer asked us to complete a statewide energy assessment.

I know other states, you know, with a host of recommendations across electric and natural gas coordination of the two and propane and cyber and physical security and emergency response, I know other states Mississippi is in the process of doing something after the February event, and other states have done similar things.

Allowing an opportunity to learn from those deep dives that states have taken, and then sort of how do you zoom out and connect the dots between states' specific recommendations in something that addresses broader system grid reliability I think is an ideal opportunity for this sort of cooperative approach.

MS. WHITE: Thank you. Mr. Howard would you like to respond?

MR. HOWARD: Yes thank you very much. So I would agree with the Chairman's comments, but we are specifically in California, that a great example of where coordinated activity you know would have been very beneficial with the Department of Safety power shutoff. You know it took place a couple years ago and for transmission dependent utilities were cut off entirely because transmission systems were shut off.

It was quite devastating. And the ability to coordinate and put boundaries and activities around how you communicate those PSTS events and how long the durations and the advanced edification as we see PSTS events now expanding throughout the west as a potential tool to address wildfire risk in some of these climate change activities, so it would just be one example of several that I think having FERC in a coordinated role with state-type regulations would be very beneficial.

MS. WHITE: Thank you. Commissioner Tawney?

MS. TAWNEY: Oh thank you and I want to appreciate FERC taking this issue on very transparently and urgently. It is critical in Oregon and across the west, but as we've heard the last two days across the country.

To put some color on Chair Scripps very excellent comments, I would ask FERC to think of the state regulators in our role, in our states as sort of the face of electricity and natural gas. We are the ones who end up in the Governor's office when there's restoration conversations alongside the utilities.

We often play emergency support functions in our state governments. And so for example, we in Oregon, is we set out temporary rules for public safety power shutoffs at the distribution level, and we ask the utilities to tell us if they have a protocol for PSTS in the bulk system.

But of course we can't help them with that. We can't tell them what we would prefer. For notification we need to look to you, and the federal level to set those expectations. And we need that situational awareness as Mr.

Howard just pointed out. It's not really critical when the event is unfolding, and we don't have good visibility into how the bulk system is going to respond.

And often the impacts of these events will be at some distance from our load centers in the left. Often you may have smoke column across the transmission line, you know, 100 miles from the population center that's going to be impacted in the west, and that creates real downstream impacts.

And without good visibility into how the transmission system is adopting to these risks of how you are setting out to be under some expectations, that we've got in a difficult position with our local stakeholders who want to argue that local is better, that long line transmission is not really the way to decarbonize and so on.

And it leaves us really struggling to answer how the whole system will be resilient when our stakeholders ask us and expect us to have an answer as the face of the regulator at the local level. So I think that partnership could really focus on that transparency and collaboration.

MS. WHITE: Thank you. Mr. Terry?

MR. TERRY: Thank you. I also want to commend FERC for raising these issues and the topics today and I think Chair Scripps has said it well. A couple of additional items I would add. I think the visibility issue that was just raised is an important one across multi-state jurisdictions, and really the changing nature of the grid generally.

I know our own coordination with the Department of Energy and FERC to an extent has helped in emergency response and crisis. The Governor's energy directors are members, I think is why I add whether it's a subset, or somehow integrated, or a parallel kind of integration to FERC to address some of the critical infrastructure interdependencies around these issues would also be a useful add to that conversation and dialogue.

Whether it's at least emerging issues which are still not very high priorities I suppose, such as vehicle, transportation electrification, and needs at the local levels and how those are served by broader reliability is one small example. There's certainly others, increased DERs, et cetera.

But I think that would be helpful and would encourage broader state engagement as well to get some of this policy and perhaps non-regulatory elements as well.

MS. WHITE: Thank you. Ms. Barbash?

MS. BARBASH: Thank you. You know I'll tag on with my other western counterparts on the panel here. I think there's several ways without repeating my written comments that were filed in this.

Several areas where more coordination could be beneficial, I mean with the shared jurisdiction of transmission I think informal coordination and collaboration can only help.

Up here in the west you know, NV Energy who I work for, operates within a lot of states. So we have one state regulator to work with, and it's been relatively easy to get the state on one page regarding the transmission investments that are going to be necessary, the natural disaster plans, to only for grid hardening but for proactive outage management and restoration, as well as you know the markets that need to be developed.

And I think you know our states can all get on one page, but we can't do it all within one state. Markets will take regional coordination. We all have different pathways of getting there, but nobody wants to increase the carbon output. No one has the goal of doing that, so we're all headed in the same direction maybe with different policies.

And you know if FERC could facilitate any way to maintain that, those state preferences for the path that we get there, but how the markets can improve. How you know, the natural disaster recovery that we're all embarking on to deal with climate change is also new to all of us.

And I think you know, any coordination or best practices in cost recovery of grid hardening, and recovery of such plans could be helpful. You know and then again you know helping with regional transmission expansion which we're going to need for resiliency as we've seen in Texas, to respond to these climate change events.

Any help that we can get to help coordinate and prioritizing federal permitting agencies and across different states would be helpful in order to increase the resiliency to us so that we can respond to climate change and natural disasters.

MS. WHITE: Thank you and Secretary Hoffman?

MS. HOFFMAN: Thank you very much. I will just re-emphasize the points that we all recognize that we have an interconnected system, blurring of the lines between the transmission and distribution as Karen brought up. But including that this raw introduction of distributed energy resources, and what David Terry brought up of the dependency issues as recognized the interdependency with natural gas.

I guess what I wanted to emphasize is really what should be the goals and focus of the coordination as part of the question. And I think we really have to take a risk-based approach with investing and building blocks which was already discussed, the visibility, the data, and the transparency so that we actually could have a coordinated conversation of what infrastructure investments are required to mitigate climate change and security risks facing our nations.

Specifically, the goal I would say is to do some sort of regional stress test, you know, whether it's every year, every other year with building blocks so that we learn from prior analysis in the work that the regions have done, and then really be able to prioritize mitigation efforts that will allow for competitive solutions to be developed, it would put the risks on the table and what the priorities are that we collectively want to address.

And then we can also build off of some of the work that the Department of Energy has done for the organizations with the state energy assurance assessment, risk assessment, resilience, maturity models, and add all that into the conversation. Thank you.

MS. WHITE: Thank you. I just wanted to check if the Commissioners wanted to ask any questions, or I can continue in the interim. I'll continue until the Commissioners have a question.

Now on question two Ms. Barbash touched with this, and it's given that climate change impacts will not be limited to a single jurisdiction, how can industry standards best evolve on a coordinated basis? Would anyone like to respond?

MS. MEYER: Commissioner Tawney I see your hand.

MS. TAWNEY: Thank you. I think this is a challenging issue as we've heard for the last two days. There's clearly a great deal of evolution that needs to happen on operating standards, and design standards, and construction standards, and on and on. I think the challenge is both geographically we face different risks in the west, the topography of the west makes us very transmission dependent, with the various communities sort of at the end of very long lines, and that's just a reality of our landscape, not because we've sort of over optimized our system.

And so solutions that work here, outcomes that work here might not be effective elsewhere. In a related -- and maybe even more important point the risk that we're trying to adapt to here is constantly changing and evolving. So we're a compliance based model of meet the standard and you're done worked in the past. It's really clear that's not going to be sufficient going forward.

We need standards that could be taking in the near data, the new reality on the ground, and evolving rapidly. So I would look for FERC to be setting out standards, or taking actions that really try to encourage that iteration, that encourage that continuous learning, maturity model approaches, and really drive after the outcome as opposed to the particular pathway to that outcome.

And throughout all of that as a state regulator, I would love to see a really deep focus on the cost-effective risk reduction. It's a critical metric. And I don't mean further discussion from yesterday about sort of how much reliability will customers be willing to pay for.

When a community needs to pump water to fight a fire, the electricity is at that point priceless. It's much more I think a question that we have limited time, we have limited resources. We're already behind on some of these risks. We have a very small population to spread these investments across our customers. We really need to know what those no regrets investments are that were mentioned yesterday. And we need some help sifting out what is needed, and what is going to really reduce risk, and what is sort of nice to have and would be an interesting option, but.

And I think that's an important challenge for us as state regulators. We don't have a lot of data to base those decisions on. We don't want to say no too conservatively. We don't want to say yes too aggressively, and that leaves us in a really difficult position, but I think FERC could help us find our way through with the practices and standards and guidance and cooperation with the labs as well.

MS. WHITE: Ms. Barbash?

MS. BARBASH: Yeah and I agree with Letha that it is a difficult issue because we are -- we all have different natural disaster scenarios as well, climate change scenarios from hurricanes in the southeast to wildfire in the west. And so we're all dealing with different types, and that requires different investments, and it requires different response and different restoration.

So it is hard to set standards. It would be easier to do on a regional basis than a national basis perhaps. But again, collaboration can't hurt on best practices, and customizing those plans towards what each area is actually going to be dealing with, and what it should be planning for.

MS. WHITE: Chair Scripps?

MR. SCRIPPS: I agree with what both Carolyn and Letha, but I also think that that sort of to the Chairman's last point, there's enough opportunity for learning here as well, in addition to standard setting. So unfortunately, you know the west is going to have a whole lot more experience with wildfires that we are in Michigan, but we do have them, but probably not enough for us to develop our own sort of expertise.

But being able to then rely on what's been done in the west when we have those events. We're taking the vast and unfortunate expertise that we have with winter weather in Michigan, for when those events strike in Texas and the south where maybe they don't have those, you know, but in terms of how we approach weatherization of lines in the generation assets and the like.

I think you know diversity is a strength and in this area too, and I think being able to learn from others who experience these extreme events more often than we do I think provides an opportunity. I also think you know to Letha's point about sort of compliance-based standards.

I think one of the most challenging pieces in this is that sort of naturally, and certainly for historic reasons, we continue to plan based on the realities of the past, and I think as we get into sort of extreme weather happening more often and in more extreme ways, we're going to require whole new disciplines to be brought into our forecasting and planning that we've never really used before, and that sort of gets to the question of how you coordinate with other federal agencies or others that it will impact later on.

But I think sort of thinking ahead to that there is -- we're going to need people who have never been involved in electricity planning to be pretty actively involved here in order to sort of anticipate what's coming and not just plan for the systems that needs to happen.

MS. WHITE: Thank you. Mr. Terry?

MR. TERRY: Yeah, I certainly agree with the comments. I want to come back to though I think the regional or subregional risks and the uniqueness that's out there in what we're experiencing in different parts of the country is the one we've been thinking about most. And we also -- I know this is not the topic, but we can't really set aside cybersecurity risks as a part of this where we might see an overlay of extreme weather and cyber.

And I was thinking what Acting Secretary Hoffman mentioned about risks, stress tests if you will. I think that might be an interesting way to go at the new kinds of weather events we're having frankly, that we're just not prepared for looking in that historical lens.

I guess lastly in this area, I think there's an opportunity to think more about the cost benefit pieces and what some of the alternatives there are from ranging from grid hardening to changes on the end use side of the equation where we had mission critical actions, which may fall outside of critical infrastructure. They could be in the fuel sector, they could be in the processing for that matter as we've seen this week as maybe an odd example, but nevertheless it's real.

So I do think we have to approach risk in a different way, and I guess quickly, one thing we've learned on emergency preparedness and response with the energy offices over the last several decades to state the obvious, those states that have experienced a lot of hurricanes or wildfires I think have a much better feel for how to address and work with this issue across borders within their own states.

If they haven't experienced these kinds of events, it's much more challenging, and I think we have to find a way to share just as Chair Scripps was saying, what we know across states and conveying the importance of thinking a little bit different about this than we have in the past, and a federal DOE coordinated activity in the states right along with the private sector.

MS. WHITE: Thank you. Ms. Wayland?

MS. WAYLAND: Yeah I concur with the remarks that everyone has made about the difficulty of having industry standards given the range of threats that are you know, that confront you based on your geography.

And I'll say that another issue with focusing in too much on industry standards is that it puts the onus for resilience for planning to be prepared for disaster response on the industry, and not on society as a whole, and resilience cannot just be the purview of the utility, and so there are a lot of stakeholders that are going to be needed to be involved in these discussions that are not necessarily within the FERC jurisdiction.

And so standards alone will not get you to the resilience that we're looking for.

MS. WHITE: Secretary Hoffman?

MS. HOFFMAN: Karen Wayland hit some of the points that I was going to make, but I'm going to just re-emphasize that standards are just the center performance expectations, and it is really retrospective. And so if we're really talking about, think we have to use the right mechanism to grab what outcomes we want to achieve.

And so if we're really talking about on a minimum level of performance, we're looking at something retrospective in the past, how do we mitigate from a lessons learned? You can really go after the standards. The standards are challenging when you want to really look towards the future, or you want to really mitigate impacts that may be coming our way, and I think you have to figure out what is the appropriate mechanism to really drive some of those future investments, and I think there's a balance in them.

MS. WHITE: Mr. Howard?

MR. HOWARD: Yeah I want to echo other people's comments. I concur with many of those. What I find is industry in the electric sector is very good at sharing. We share lessons learned quite often, whether they're publicly on the utility, an investor on the utility, or a rural electric, I mean we don't seem to have a lot of boundaries there in sharing information through a lot of our different professional organizations.

And so I think that is already built really well. Where we seem to be having a lot of problems I've been dealing with wildfires now for six years straight impacting our facilities, our communities, and we seem to be having to deal with more challenges in standards and regulations when it comes to the recovery and the rebuilding evidence, and trying to rebuild in a new way to maybe not run into the same issues that you have previously become more and more difficult.

And example would be you know we had a number of wildfires, and this takes place along the whole west coast, where you know when you have wildfires and they burn through these watersheds, and then you hit that winter season and all of a sudden you have the rainfalls, the heavy rainfalls, and all the hillsides come down in and fill up our reservoirs and our hydroelectric bands are filled up with assignments.

You know you have the standards under which we can remove it outside and we're built for these types of activities. And so what we find is more of the standards that are in place today become bigger barriers for us to recover quickly and move on to prepare for the future, and so yeah I'm just challenged sometimes with historical standards that are used, and how we're moving in some of those events in the current climate we are working in.

MS. WHITE: Thank you. Commissioner Tawney?

MS. TAWNEY: I just wanted to very quickly, build on Secretary Hoffman's point around finding the right metric, the right incentive. We're experimenting in Oregon with some performance based ratemaking around the vegetation management and wells hardening for exactly that reason.

And I think it's a conversation we need to have more broadly about how do we really set out the end goal that we want to have these facilities deliver on, and then give them space to go figure out how to do that because we can't -- we will not be able to dictate the right answer, the right balance, for the OEM capital prospectively, so I look forward to all the research we can get for doing that, all your research programs on how we can deepen our metrics for performance-based ratemaking on some of these fronts.

MS. WHITE: Okay great. We'll go on to the next question. Should some type of formal or informal collaboration by regions be pursued in order to focus on region-specific climate change and extreme weather needs? Would anyone like to tackle that one? Chair Scripps?

MR. SCRIPPS: I guess in the interest of getting the conversation started on this. I mean yes, and I will say one of the things that we learned coming out of 2019 was and it's been mentioned already, but the interdependence between the electric and the gas sectors. And that's not necessarily a region-specific thing, but I'll say in Michigan and across a lot of the northern Midwest gas is our primary heating tool.

In Michigan it's 25 percent of homes use gas as their primary heating tool. You know RTOs are by definition electricity focused, and they have a responsibility that they take very seriously, and they should, to maintain the reliability of the electric grid.

But as a greater percentage of both PJM and MISO's fleet is gas-fired, what do you have -- what do you do in a situation like we had in January of 2019 where you have gas constraints as a result of the inaccessibility of some of the underground storage in Michigan caused by a fire at a compressor station where the gas system is in real jeopardy of not being able to continue to deliver heat.

And at the same time MISO has called a max gen event and needs all resources online. And I think that's a place where regionally, and with federal partnership again, we need to understand the priority stack. When you need the same gas flowing for two different purposes, which one wins out?

And I know how I would answer that in Michigan, just given the difficulty of reconnecting people if we had a guest on a disruption. But that's sort of asking for forgiveness after the fact. And I'm not even sure that I'm the person that gets to answer the question. And so I think real clarity ahead of time, and that's probably regional among states that share certain attributes, but we had scheduled partnerships again so that we know going in to that sot of emergency situation exactly how we're going to respond, and that we're going to be backed up at the end of the day.

I think that's going to be really important. The other one that I'd say is probably also of interest is you know folks don't really care why their electricity goes out -- if it's a transmission failure, or a distribution failure. And if there are opportunities to look at resilience on the distribution grid, and I will say I know I'm from Michigan, but the Ford announcement, and the number three selling point of their new electric truck is it can power your house for three days, or 10 days if you're rationing.

And so starting to think about how those new technology applications provide resilience on the distribution grid, you know, that's not FERC jurisdictional, but it certainly gets into the issue of if transmission which is -- and again, that probably goes back to question one, overlap and the need for dialogue on these cross jurisdictional issues.

MS. WHITE: Thank you. Secretary Hoffman?

MS. HOFFMAN: So I'm probably going to be a little bit blunt on this question. And I think we have to realize that we are transferring a great amount of risk to consumers as we talk about this dialogue, and so therefore, I mean regional insight is extremely important. And I think we recognize that there are challenges out there, and we look at the lack of investment and capacity.

We look at resource adequacy issues, we look at lack of hardening. We look at the inability to set priorities as we want to mitigate contingencies. But I think we have to think about this that our investments need to be on behalf of consumers and customers, and you know, the ratepayers as we move forward.

So we have to keep in mind the affordability as we look at how we want to provide signals, market signals, but visibility and awareness to consumers for their decision whether it comes to distributed energy resources. You know as some of the discussions that were talked about earlier with respect to emergency pricing and scarcity pricing, we have to really think about the promise of what we were looking at as we look at markets.

But how do we really ensure affordability to consumers who it's for? So to me having that information that's available will allow for educated decisions by consumers, but also affect of emergency response and investment decisions moving forward, thank you.

MS. WHITE: Thank you, Commissioner Tawney.

MS. TAWNEY: Those are approaches, really excellent points raised by my colleagues. I think I would add a more mundane, or more foundational point which is I think at a regional level we, or at least I as a decision-making, and I think as our utilities work through their integrated resource planning and begin to try to think about what a mid-century climate, or even within our IRP horizon what that climate looks like, we struggle with sort of the downscaling and application of climate models.

What is it we're planning to? And especially as we way -- we have a long-lived asset at the distribution level, but also the costs of transmission upgrades and transmission hardening coming through rates, how long will those last? We are already getting questions in transmission siting about whether lines are designed for mid-century fire regime.

And I don't have necessarily good answers for that. The utility has made their design efforts, they have hired their experts, and I think regionally when I think about the west there is a way in which this climate impact is going to unfold across the west through the Rockies and the Great Basin, and we need to be talking to each other and tapping national level resources to understand what it is we're even planning to.

And we need some help with that. I think we have great local institutions here in Oregon. We have Oregon State University that can give us downscale climate impact, but applying that to the electricity sector is not their skillset. And we need some help with making that bridge so that we really have a sense that we're putting steel in the ground that's going to be useful in 10 or 15 years, and not creating a new resilience problem.

And I think we need to do that in a regional conversation because we're all experiencing the climate change in a similar way and can find some economy to scale in that dialogue.

MS. WHITE: Thank you. Mr. Howard?

MR. HOWARD: Yes thank you. I'm going to touch on this from a little different perspective from regional collaboration just a need that require. Some of the panels have touched on it regarding mutual aid and the ability to support one another when things get very difficult.

And using wildfires we had a situation where five of our employees lost their homes, and many more families were evacuated from their homes due to wildfires coming through the areas, and really at that point you can't really on that staff. That staff needs to address the critical needs of their own family in getting their family to a safe location.

But what we really need more of is just that collaboration on a regional basis. We can support staffing needs and resource needs and we found this as well when many of our members were looking to support Texas when they had their issues with transformers and equipment to support them, so they could do their restoration efforts, and then the wildfires came, and we had a need and didn't have sufficient transformers.

But those types of regional collaborations become quite critical. And if you're in the middle of a crisis we'll recover in that crisis, and that regional collaboration is just so important for us to be better prepared for these type of activities.

MS. WHITE: Thank you. Mr. Terry?

MR. TERRY: I think just two areas I would add, and I certainly the answer is yes on regional coordination. I would emphasize again I think there's something to be said for subregional if you will, the unique characteristics we see emerging in some markets.

Florida is a great example. The last major hurricane event they had the end I think, the hotwash of the situation the state decided they needed to reduce the evacuations by about half. That is another kind of transference of risk, but also puts them in a very unique position of how they need to address their electric sector, which I think they're well on the way to doing, but that's very different than some of the predictable interdependence we see from hurricane events in the southeast that result in fuel interdependencies.

Colonial Pipeline fuel interdependencies as an example. In the northeast we have a number of states that are pursuing very aggressively electrification policies in the residential sector where gas limitations of the types Chair Scripps mentioned are a very serious problem.

And we're transferring fuel risk if you will from delivered fuels to electricity in a way that even around the margins will have a very big impact. So I think there's another layer here that is very specific that is a near term. I think there's an urgency to this issue that needs to be action, and I think we need to move more quickly. And to me that says we probably need to go beyond the regions to hit some high priority risk areas just by nature of either the weather risks they have, or the system and policy risks that are being baked into the future.

MS. WHITE: Thank you. and Ms. Barbash?

MS. BARBASH: Thank you. You know I think I overlapped a little bit on the last question about you know regional coordination being necessary because of the similarity and the differences in the types of the climate change initiated natural disasters.

But you know I think it spans across all timeframes for a real time when you're in an event, you know, our reliability coordinators have more situational awareness than a piecemeal by piecemeal, you know, this is how things are affecting me, so this is what I'm going to do.

And that's really their role. And more coordination on these new efforts. You know this is new to all of us, all of this. And then in the planning stages you know are there regional projects that can provide more redundancy than a local project? So we need regional coordination on that.

And then we need regional standards on you know whatever kind of climate change disasters you may be facing in your region, whether it be wildfire, earthquakes, hurricanes, the type of grid hardening investments that are best practices to kind of repeat what Commissioner Tawney said.

And then lastly, how is it all being paid for? You know again, it's a multi-jurisdictional asset. We are hardening the distribution grid and the transmission grid, and to the extent that there's multi-beneficiaries, what's the best process for recovery of this?

So there's different time horizons, and collaboration, that's all I know.

MS. WHITE: Thank you and Chair Scripps?

MS. SCRIPPS: Yeah I know I have already spoken to this, and I know that the question is on regional collaboration, but I didn't want to leave this without also just underpinning the need for interregional collaboration. When you look at the transmission planning it's hard enough within a RTO, but with the process of transmission planning between RTOs and across is next to impossible.

And you know, and so I think we all know why. I mean we can answer why we're in the system and it makes sense on its face, but as we sort of move into a future that's more unpredictable and where transmission can help address some of those things, you know it's not going to be enough that we know that power flows between markets and then we can deal with it in the settlement process.

We've got to find a way to break through that sort of siloing between RTOs, and find ways that we can get projects done that sort of cross those jurisdictional boundaries.

MS. WHITE: Okay. Oh sorry.

MS. MEYERS: We'd like to switch gears slightly, with just that Commissioner Clements is traveling. She's listening in to the panel and she sent us a question, so I will convey it to you. She's asking we've heard that the standards alone aren't sufficient. What mechanisms beyond standards should the Commission put in place to mitigate future impacts?

MS. WHITE: Ms. Barbash would you like to answer that question, or was that hand up from the previous question?

MS. BARBASH: You know that hand was up from the last question, but can you repeat that question I'm sorry.

MS. MEYERS: Absolutely. The question is we have heard that standards alone aren't sufficient. What mechanisms beyond standards should the Commission put in place to mitigate future impacts?

MS. BARBASH: Well since I accidentally had my hand up, I will just say that I don't know that we're ready for national standards. Again, I think each case is so unique. Each region is so unique that we need to start with collaboration before we start with any hard and fast one size fits all standards.

MS. WHITE: Commissioner Tawney?

MS. TAWNEY: Well thank you for the question, and I appreciate that you're listening even as you're on the road. We're all stretched so unbelievably thin as we tackle all these challenges. So I really appreciate the challenge that you have, that FERC staff faces in grappling with all of this.

We're grappling exactly with this question when we are trying to write rules on wildfire mitigation planning right? We don't manage the utility, but we need to somehow review their plans for completeness, for safety, for reasonableness. We'll do a purview review after they've made the investments, but what standards will we hold them to?

And I think we keep coming back to what are the outcomes we want to have and what can we measure right? Few ignitions, smaller PSPS, fewer customers impacted for shorter amounts of time when you do have to do a PSPS for example.

But also how are they accessing the best risk-based analysis? How are they bringing evolving risk analysis into their decision-making so that the choices that they do make whether it's design standards, or operational practices, really meet the risk where it is and where it's going to be in five years.

If it take you four years and you're on a four term cycle for your vegetation plan, you've got to determine for where vegetation is going to be, you know, I'm already having a wildfire challenge, you know it can't take four years to absorb a change in what needs to be trimmed, or to adapt to changing tree mortality for example.

So I think that I don't have an answer, but I will say as a state regulator we're grappling with the same question at distribution level and we're feeling -- I am feeling very hungry for more data to try to base the decisions on and to set out the incentives for those kinds of choices.

And I think incentives are important because we actually don't know quite which technical solution is going to work or be best, and so I couldn't define you must use a steel pole there. You must use these kind of reclosures here, but a non-explosive fuse there. It would be ridiculous for me to try to do that. Who knows what's going to emerge as the best solution.

How do we get our arms around the data, so that we're making good choices? And what are the no regrets investments? What are the ones that are just applicable across a range of disasters? We went from fires unlikely ever seen on Labor Day here in Oregon, to an ice storm that brought two inches of ice to a part of our system that had been engineered for a half inch because we have never historically seen anything more than that.

And we have some of the largest, longest duration of largest outages in February that we've had in our history. And that's you know in less than six months swing. It's quite a bit to absorb, so I'll leave it there, but I'd love an answer as well.

MS. WHITE: Thank you. Mr. Howard?

MR. HOWARD: Thanks for the question Commissioner. I think there's a place for universal standards, and we've already heard that universal doesn't necessarily work for every region, but as a utility operator, cold based guidelines, so out of FERC maybe guidelines that are more concerned or related to performance, or advisory positions at FERC are very useful for the utility sector versus just rigid requirements.

Those are just some of the things that I would suggest as we're walking through a transition, and not knowing exactly where that place is going to be, and so I would recommend more along the guideline approach.

MR. WHITE: Chair Scripps?

MR. SCRIPPS: I agree with a lot of what Commissioner Tawney said, not surprisingly, but I want to sort of expand on two of the points and then add one. I totally agree. I think if we knew the answer here we would sort of that would be the answer. And so we've got to provide some space for experimentation and innovation, and I think that incentives can play a role in that to figure out what are the right technological fixes that rises to the top when different approaches are tried.

But that's based for experimentation backed by some of incentives to sort of encourage utilities to go in places that they might not otherwise I think is a really important piece of figuring this out when you don't have experience.

The second piece that she mentioned was some of those no regrets. I would say I know Alison yesterday was talking in one of the panels, Alison Silverstein, on some of those things. So we know that more flexible load can help with this. We know even though it's not sexy, that energy efficiency can play a role in this, so it just helps the system overall.

There's a certain amount of transmission build out and we can argue about what that is, but it is least regrets, or no regrets, and I think that just prioritizing these things as we continue to sort of figure out some of the pieces. And then the last is I know David mentioned sort of cybersecurity, not the topic today, but some of the ways that we're addressing challenges that we can't figure out yet that continue to evolve faster than the regulatory process I think have a place here.

By the time we impose a rule on our utilities, you know, that cyberthreat is six generations in the past, and so instead we've used things like DOE C2MT self-assessment tools, and just keep asking questions. And that sort of process based approach as opposed to a standards based approach, particularly in sort of fast-evolving areas I think has you now applicability here to.

MS. WHITE: Thank you. Ms. Wayland?

MS. WAYLAND: Yeah. I mean we've been talking about investments that utilities would need to make perhaps system-wide, but you know Commissioner Clements you're asking what else can FERC do other than standards? And I think a lot of the focus when it comes to climate and FERC has been on emissions.

And how you might use the Federal Power Act and other authorities at your disposal to deal with emissions associated with such projects. But I think there's also a question about whether you need to use statutory authority to look at the climate risks of new infrastructure -- what kinds of risk ought we need to be addressing when a project is being constructed.

So I don't have the answer, but I think it's worth you know, those who are legal experts at FERC's authorities to look at to what extent you have authority within project approval processes to deal with the climate risks.

MS. WHITE: Thank you. Ms. Barbash?

MS. BARBASH: Thank you and I'm going to lower my hand. You know I had some more time to think about this question, so Commissioner Clements. So really not new standards, but maybe some evolution of some ancillary services that FERC already has jurisdiction over, already has in place. For instance, you know the operating reserve.

Maybe we need more flexible ramping capability to deal with intermittent resources that we're trying to put in place to combat climate change, and to deal with some of the natural disasters. In Order 888 we didn't have a back stop service required as an ancillary service.

And today when we're replacing these load serving entities can get their deliveries and their resources in, you know, we really need to think about do we shed load, or do we try to serve them if we can as a transmission provider that does have resources. And some sort of back stop service may be helpful at this time, where it wasn't in the past.

MS. WHITE: Thanks and Mr. Terry?

MR. TERRY: I think it is obviously a great question. I agree with what's been said. I think one of the elements that might be helpful in parallel to this, obviously no regrets items that need to occur on an expedited basis, but I think there's also an educational component for the non-energy state and local leaders, non-energy business community leaders.

I'm not sure that it necessarily is a public issue, but about the cost and expectations of some of the risk management, some of the risk that needs to occur. When I think about how much time and frankly federal tax dollars, state tax dollars we've spent in dealing with the aftermath of the cold snap in the south central part of the country for ratepayers and others.

Obviously, that needed to occur. That's an extreme event. But I also think there's some level of education about the cost benefit if you will from the non-energy community, and I think that would be another helpful piece that would help at least make these actions more possible from a political perspective, and from a willingness to act perspective at the state level.

MS. WHITE: Thanks everyone and we'll go onto the last question. Are there opportunities to beneficially coordinate with other federal agencies on climate change and extreme weather? Ms. Wayland?

MS. WAYLAND: Yes there are lots of opportunities, but it turns out not to be so easy to do that kind of cross agency coordination. There are at least 20 different agencies that have some oversight into the energy system and even if we just look at the electricity sector it's a large number, you know, everything from Bureau of Rec and how much water do they have in their reservoirs, to the permitting processes that happen across the agencies, the data that's available at NOAA for forecasting and the National Labs.

It is critical to do coordination across agencies, but when you know in my experience, when you have a large number of agencies in a very large issue area like climate change, it's far better and I think somebody mentioned it early on, to have specific questions that you want to tackle so that you can actually narrow the number of stakeholders that you want to bring together around to six, but it is critical.

And I think that the states would love -- and David could speak to this, would love to have better coordination at a federal level for the delivery of different services that we can offer in this area.

MS. WHITE: Thanks Mr. Howard?

MR. HOWARD: Yes. I'll just touch on one of those types of activities that I think has been successful. I co-chair a wildfire working group in the electricity subsector coordinating council, and I co-chair with a CEO from the investment and the utility and a CEO from the rural electric, and we directly meet with federal agencies to talk about mitigation activities on the front end on how we could mitigate wildfire risk and what parts of the measures need to be changed from the vegetation management to other things, to what do we do when we're in the midst of a wildfire and the coordination or distinction of that fire as quickly as possible to the recovery and the rebuilding at the back end.

And I think it's been a really good example of how it can be handled when you get to these emergencies, and these types of climate issues. So I would close out with a good model, and one that could continue to be expanded on. We certainly need more participation from other folks in federal agencies, but it's been good so far to get things accomplished.

MS. WHITE: Thank you. Chair Scripps?

MR. SCRIPPS: Yeah. So I agree with Karen. I think you know the Biden administration I think is to be commended for taking you know part of what we've talked about is this whole government approach. I think the two pieces that are really critical to that are one coordination, and I think you know the role that Gina McCarthy and her office plays, even the way it's coordinating across agencies tend to be understated in this, in terms of making it work and that everything is happening together.

And then sort of relatedly, it needs to be focused on execution. So how do you get into the weeds and take on specific tasks and not just sort of falls under its own weight. And again, without being silent, so that coordination function sort of is there at the back end too. The one piece that I would add that may not actually get covered in here is where this shows up in terms of the emergency response.

And so involving groups like FEMA that may be left out of this conversation otherwise, but are absolutely critical you know when things go back in getting things back up. You know we've seen it in Puerto Rico, we've seen it in you know, any number of instances where we're going to need greater coordination.

And then from the state role where that shows up is you know our state emergency operations center is housed within our state police. So both between the federal government and the states, and then within the states also making sure that we know who are partners are, making sure that those relationships are strong before an emergency, so you're not asking you know who this person is, and who that person is sort of as the emergency is unfolding.

You know we've learned some lessons both through the 2019 polar vortex, but candidly also through COVID and COVID response that hopefully we can sort of build on and leverage to make sure that we're better prepared on a going forward basis.

MS. WHITE: Thank you. Ms. Barbash?

MS. BARBASH: Thank you. You know I would start by saying that at the risk of sounding very na ve, or maybe the first thing we should start with is figuring out why it has to be so hard for federal agencies to coordinate. And then secondly, I would say that there's a lot of opportunity there.

You know, the obvious thing in the west, and I keep going back to that because that's where I have the most experience. But it is in the amount of federal lands that we have, and the multiple agencies that have jurisdiction over permitting on federal lands.

And it's really helpful to have one agency take over a project, and run the NEPA process from beginning to end, coordinating with all other federal agencies, whether VLN, or Forest Service, one of them taking charge and coordinating with the other as well as all the counties, cities and local jurisdictions in order to get the permitting done.

It's also very important to have a consistent method for these NEPA processes, so they can't be questioned later -- an expedited process for it in the world we're dealing with now. We can't decide we need transmission and then take 10 years to build it. That's just not an option right now when we're trying to get reliable dispatch of renewables, access to renewables, it can't take that long.

And you know and then just maybe where FERC can be involved because it knows the projects which should be a priority for resiliency redundancy, accessing renewables for climate change, and maybe some prioritization of those projects. And even from a federal standpoint, one point of contact when managing resources and budget for these projects as well, and you know those are my suggestions.

MS. WHITE: Commissioner Tawney?

MS. TAWNEY: Thank you. There's been a lot of great suggestions, and the federal lands issue is really important in the west. I have really appreciated the work that the electricity subsector council has done on fire.

I think they've really smoothed the path for education management on federal lands, although there is just the task is enormous around the infrastructure rights-of-way, but they are at least having the conversations, and we have seen movement out here in Oregon, for example with the federal agencies on getting better access and so on.

But I think to raise a really narrow specific issue you know the FCC has you know deregulated the communications sector, and you know we carry the emergency support function for communications and energy in our

Commission, and we find over and over again that this conversation that we're having here about resilience around a critical service isn't happening in the same way in broadband and cell, and other areas of communications.

And where that lacks with meeting to do, for example, public safety power shutoffs because it is simply too unsafe to run the electricity system in some weather conditions, and their response is to ask ratepayers to harden the lines out to the cell tower. And I think we have a real challenge here around who's job is it? Who's pocketbook should the resilience investment come out of?

And someone earlier had raised just as a societal issue, and this is just this FCC question is a very narrow expression about that larger societal issue. Utility ratepayers cannot make the whole societal infrastructure resilient. We can do our pieces, but there needs to be really deep engagement or urgent conversation at least with some of the other critical services sectors about what they're doing to be ready.

Because as much as we want to you know educate that there is going to be a cost benefit to these investments, we're not going to get better reliability than we've had in the past. We're going to get better reliability than we would have if we hadn't adapted to climate change.

We're going to see it at least in the west for some time reduce your liability at a higher cost as we try to absorb the impact of climate change, and that is going to be difficult for customers to understand if we have to also then, trying to build out resilience for the whole essential services sector, because they didn't make the investments, we'll be really, really stuck.

And so at the federal level having those hard conversations would be really welcome from a state regulator perspective, so they're not conversations that I can necessarily move the ball on, but are coming home to roost when the cell tower that supports the first responders in a county goes down, and they can't talk from one side of the county to the other, they sort of end up in my office and I can't help, and that's very frustrating. So I'll end with that specific example on the table as something that would be great to work on.

MS. WHITE: And Mr. Terry?

MR. TERRY: Thank you. I think this is one of the more important questions I thought from a state energy office perspective. We have I think a great foundation of federal coordination to build on with the Department of Energy, your office and also some electricity in the emergency response, and to an extent mitigation space to build from, the collaboration there across agencies and fuel types have been I think having seen it go from very limited two decades ago to what we have now, maybe that perspective that the bar seems maybe better than people think.

I think we have a lot to build on there, though whether that's a resilience council of some kind of not, but I think that's a great starting place. Something Karen Wayland said that really resonated with me. I think we need to pick some actionable high priority areas and then focus in on those, and use that sort of existing foundation that we have in those two sectors.

And one maybe small sliver of that that I think would be a great example, the FEMA brick program which really has an important energy element, and I think in DOE's help with the energy offices and the Commission's, to help utilize those funds that are in the billions of dollars each year now as a result of the Disaster Recovery Reform Act.

That's a very ripe opportunity, and certainly FERC engagement in that process would be welcome and certainly very useful. So I think those are a couple of specific actions that we would call out.

MS. WHITE: Alrighty thank you. Very interesting discussions, and we thank everyone for participating in both the conference and this panel, Alyssa?

MS. MEYERS: We have reached the end of our panel. So yes, and thanks as well and we'll now turn to closing remarks.

MR. AMERKHAIL: Thank you Alyssa and Lodi. Thank you to all of our panelists on both days, and to the rest of the FERC team that put this conference together which includes Jesse Hensley, Alyssa Meyer, Patricia Shab, and Peter Whitman from the Office of Energy Policy and Innovation.

Sam Hile and Dianna Mobely from the Office of Energy Market Regulation, Michael Haddad, and Norman Yokodonovat from the Office of General Counsel. Ena, Louise Netter and Lodi White from the Office of Electric Reliability and Sarah McKinley, Ester Burdenlee, Masume Malda, Phisa McNearn, Ricky Hernandez, Troy Miller, Niam Majad and Karen Williams from the Office of the Ranking Director. That concludes this technical conference on climate change and extreme weather. Thanks to everyone who attended, and we are adjourned.

(Whereupon the conference adjourned at 5:50 p.m.)

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceeding before the FEDERAL ENERGY REGULATORY COMMISSION in the Matter of:

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were held as herein appears, and that this is the original transcript thereof for the file of the Federal Energy Regulatory Commission, and is a full correct transcription of the proceedings.

Larry Flowers

Official Reporter