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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.

1 Opening Remarks

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

4 David Patton, President, Potomac Economics

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

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

9 Renuka Chatterjee, Executive Director of Systems Operations,
10 Midcontinent ISO

11 Wesley Yeomans, Vice President of Operations, New York ISO

12 Anne Hoskins, Chief Policy Officer, Sunrun, Inc.

13 Mads Ronne Almassalkhi, Assistant Professor at the

14 University of Vermont, and Chief Scientist at PNNL and

15 Co-founder of Packetized Energy.

16

17 Panel 4: Recovery and Restoration

18 Kevin Geraghty, Senior Vice President of Electric

19 Operations, San Diego Gas and Electric

20 Daniel Brooks, Vice President Integrated Grid and Energy
21 Systems

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

24 Michael Bryson, Senior Vice President of Operations, PJM
25 Interconnection

1 Brian Slocum, Vice President of Operations, ITC Holding
2 Jodi Moskowitz, Deputy General Counsel and RTO Strategy
3 Officer at PSEG.

4 Panel 5: Coordination

5 Karen Wayland, Chief Executive Officer, GridWise Alliance
6 Randy Howard, General Manager, Northern California Power
7 Agency

8 Dan Scripps, Chairman, Michigan Public Service Commission
9 Letha Tawney, Commissioner, Oregon Public Utilities
10 Commission

11 Carolyn Barbash, Vice President of Transmission and
12 Development Policy, NV Energy

13 Patricia A. Hoffman, Acting Assistant Secretary, Principal
14 Deputy Assistant Secretary, Office of Electricity, U.S.
15 Department of Energy

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1 P R O C E E D I N G S

2 Opening Remarks

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

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

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

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

1 speak today.

2 This conference is being webcast and transcribed.

3 With those reminders out of the way let's get started with

4 the third panel entitled, "Operating Practices for

5 Addressing Climate Change and Extreme Weather." I'll turn

6 it over to our moderators thank you.

7 Panel 3: Operating Practices for Addressing Climate Change

8 and Extreme Weather

9 MR. WHITMAN: Thank you. I'm Peter Whitman from

10 the Office of Energy Policy and Innovation, and along with

11 my colleague Elizabeth Topping, also from the Policy Office,

12 I'll be serving as moderator.

13 This panel will explore the ways in which

14 existing operating practices, including but not limited to

15 those pertaining to seasonal assessments, outage planning,

16 and coordination, reserve procurement and the insight

17 management unit commitment of dispatch, short-term asset

18 management and emergency operating procedures and they

19 necessitate updated techniques and approaches in light of

20 increasing instances of extreme weather and longer term

21 threats posed by climate change.

22 We will be foregoing opening remarks for this

23 panel and will move directly into a question and answer

24 session. Following this panel we will have a 20 minute

25 break. I'd like to start by introducing our panel three

1 panelists.

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

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

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

25 Once we do so, please turn on your microphone and

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

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

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

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

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

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

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

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

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

25 MR. YEOMANS: Good afternoon, and again thanks

1 for inviting the New York ISO to this panel. The majority
2 of our extreme weather concerns at this point in time, at
3 least the last five or 10 years have been extreme cold
4 weather. We certainly can have heatwaves in New York City,
5 and we expect to have more of those.

6 We experienced the severe Hurricane Sandy which
7 hit New York City and Long Island, New Jersey and
8 Connecticut back in the late 2012, ice storm in the late
9 90's, but for this question from a market structure and
10 rules perspective, I'll really be talking about things that
11 we've done to better prepare for the very cold weather
12 operation with limited pipeline capability.

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

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

1 reliability issues.

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

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

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

25 In the world of regulation service we've

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

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

18 And then from a reliability rules perspective
19 different than market enhancements, we have improved our
20 weekly dual monitoring capability, testing every six months
21 to make sure the dual field units can start annual generator
22 visits to make sure they're ready for hot and cold weather
23 operations and extreme weather, improved our communications
24 with the gas industry, emergency procedure for the gas
25 industry, and we've always even before polar vortex at our

1 oil burn rules that require a certain number of generators
2 to have dual fuel capability.

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

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

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

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

21 Shortage pricing is incredibly important because
22 it not only allows you, allows the RTOs to price and send
23 efficient incentives for things you might foresee coming
24 with some degree of probability, but also maybe even more
25 importantly it helps you price and send incentives to deal

1 with situations that are highly unlikely that you don't see
2 coming, and extreme weather events definitely fall into that
3 category.

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

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

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

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

7 MR. WHITMAN: Interesting, thank you. Renuka?

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

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

21 Specifically with regards to market structures,
22 forward looking actions to improve generation performance,
23 MISO certainly thinks that winterization is a critical
24 element. MISO's footprint we have you know extreme cold in
25 the north, and extreme heat in the south, so we do face both

1 those extreme situations. Specifically for extreme
2 weather events, again we could put in mechanisms such as
3 scarcity pricing that we talked about, or seasonal
4 constructs amortization, but when you get into the actual
5 event we must recognize that you have what you have and try
6 to maintain the liability at that point.

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

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

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

1 want to look instead of the footprint, not outside the
2 footprint to import energy.

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

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

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

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

23 And Hurricane Harvey the average price was for
24 two different zones was \$23.00 and \$37.00 a megawatt hour.
25 And then we contrast that with polar vortex in winter storm

1 events. And so during the 2014 polar vortex NYISO prices
2 were \$180.00 a megawatt hour approximately, and then of
3 course we know this past February with Winter Storm Uri
4 prices were extraordinary high in ERCOT, over \$6,500.00 a
5 megawatt hour.

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

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

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

25 But something that we've been looking at at EPRI

1 is thinking about how we can almost forecast reserves, and
2 the importance of using dynamic reserves. Folks have been
3 thinking about dynamic reserves for renewables, but why
4 can't we then also do that for weather and temperature.

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

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

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

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

25 Last summer, excuse me, in California we were

1 called personally by the Commission -- the Public Service
2 Commission here to ask if we could get our customers to
3 participate. As if we could get our customers not to
4 charge. Ask customers to share their power, but we weren't
5 compensated for it.

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

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

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

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

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

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

23 MR. WHITMAN: Thank you. We also have a question
24 later on oriented more towards flexibility demand which
25 might incorporate these questions in the comments that you

1 have. If there's no other, are there any other questions,
2 comments, just starting on this particular on our first
3 question? If there is no one else then we'll go with our
4 next, we'll start with our next question thank you.

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

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

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

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

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

23 So it is very important in predicted tight
24 conditions, or unexpected conditions that we can get
25 transmission. I recall there may be more important don't

1 let it out in the first place for ordinary scheduled
2 maintenance, you know, forced outage is unavoidable, but if
3 there's the ability to move scheduled outages to other low
4 level time periods or less stress conditions we always
5 strive to do that.

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

13 So in a world of transmission infrastructure we
14 can recall it and get it back. And so if we work with the
15 transmission owner and they say they can get it back in 6,
16 10 to 12 hours, or maybe even 20 hours they we can allow
17 some longer term outages, or we'll watch the weather
18 carefully, and we think we have confidence out about two or
19 three days.

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

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

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

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

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

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

25 MS. CHATTERJEE: Thank you. Pretty similar to

1 what Wes mentioned, MISO has the authority to reschedule
2 transmission outages and cancel the generation outages as
3 necessary again. The authority that comes with all the
4 responsibility because ultimately when you defer maintenance
5 you could be perpetuating generation performance problems,
6 so we don't want to necessarily move maintenance down the
7 road all the time.

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

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

23 So in terms of is it sufficient? I don't think
24 it's sufficient. We're trying to do additional things like
25 maximize transmission line ratings, or look at switching

1 options to kind of minimize that risk that we are seeing in
2 the shorter months. We think again moving to some of that
3 seasonal construct other places will allow us to make that
4 risk more transparent so we can actually adequately plan you
5 know.

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

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

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

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

1 weather event can really create a concern.

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

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

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

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

25 MS. HOSKINS: Hello again. So I do want to

1 mention that one of the drivers for why people are
2 installing batteries with their solar system, particularly
3 in California, but also in Puerto Rico is when transmission
4 systems haven't been working. You know when there have been
5 the forced outage, or required outages, intentional outages
6 by PG&E in particular where we are having days, you know, it
7 went for a few days a few years ago, now they're shortening
8 it.

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

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

24 And as long as we can figure out how to
25 compensate those for what they're offering and which I do

1 believe can be seasonally adjusted, it's just something we
2 have to keep into account. We have certainly seen some
3 studies of how that the increase in batteries and storage
4 have resulted in some reductions in the need for
5 transmission build in parts of the country.

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

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

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

20 MS. HOSKINS: Well when I say called I mean
21 physically a phone call to all of us from the CPUC which is
22 the biggest challenge right? I mean we actually don't have
23 the system set up yet to either call or to compensate. I
24 mean we do have some -- the DER program and others through
25 CAISO, but there's just a tremendous amount of work that has

1 to be done and my understanding is that there are some
2 interconnection challenges along with that.

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

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

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

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

1 across the RTOs?

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

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

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

23 That's a case where MISO technically can't deny
24 the outage because it's purely an economic impact, but it's
25 also a case where the system is vulnerable to reliability

1 problems. If another unit has an outage in that pocket, or
2 there's some weather events that creates an additional
3 outage, so I think improved authority would be good across
4 the board. But on the incentive side I did want to say one
5 more thing.

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

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

20 So we've been recommending in New England, New
21 York and MISO that they all approve their accreditation, and
22 have it be based in large part on generators being there.
23 And that would help on outage scheduling because if you know
24 you're going to lose capacity revenues because you're on
25 outage during tight conditions, then it brings your

1 incentives into alignment again with the RTO on outage
2 scheduling.

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

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

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

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

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

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

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

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

25 MR. WHITMAN: Thank you. Finally Anne do you

1 have a follow-up, or is your hand up?

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

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

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

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

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

21 And you know as the country decarbonizes, it will
22 become more reliant, at least in the short and medium terms,
23 on reliability gas supply for that flexible you know,
24 flexible generation to balance out the renewables that are
25 coming online. And those gas generators that will be needed

1 will have lower capacity factors, so that's going to create
2 you know some real misalignment of incentives in terms of
3 contracting for gas supply as generators are more reliant on
4 reliable gas, but also need more flexibility for when that
5 gas is provided.

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

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

23 But what's not required on those Hinshaw in 311
24 pipelines are standards of conduct that separate the
25 transmission and marketing functions, transparency is not

1 required, so there's no electronic bulletin board similar to
2 the ones that are required for interstate pipelines.

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

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

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

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

25 DR. PATTON: Yeah, so unfortunately almost none

1 of the compensation that transmission owners get is
2 market-based, it's all embedded cost recovery through
3 regulated rates. And so if transmission owners can do
4 things to increase the transfer capability on a constraint,
5 they don't benefit from doing that.

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

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

22 So that's an example of one small way that
23 transmission owners in one location are being exposed to
24 market incentives. But I think you know we could definitely
25 brainstorm how to potentially give them access to some

1 market incentives because even when we talk about for
2 instance your transmission incentive ideas and policies and
3 MOPR and so forth, it's all sort of characterized as should
4 we increase or decrease the rate of return that transmission
5 owners receive, which is all back in the sort of embedded
6 costs mindset.

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

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

16 DR. PATTON: Yeah sounds good.

17 MR. WHITMAN: Thank you.

18 COMMISSIONER CHRISTIE: Thank you.

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

23 MS. CHATTERJEE: Thank you. Fuel availability
24 is one I think that has a lot of attention as it is under
25 the electric gas coordination. As of now MISO conducts an

1 annual winter fuel survey assessment that allows us to
2 collect some information on you know fuel availability,
3 specifically with regards to actual gas availability.

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

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

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

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

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

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

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

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

25 So that signals that we could do a lot better at

1 coordinating gas and particularly pipeline capability.
2 Although it doesn't require the same degree of coordination
3 that the delivery of electricity does because the physical
4 characteristics of delivering electricity are far more
5 complicated and rigid than gas. You have a little more
6 control over gas delivery.

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

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

24 Because it's really hard to figure out I think
25 when you're trading on Friday what you're going to need

1 three days later. Okay, that's all my comments.

2 MR. WHITMAN: Great, thank you. Robin?

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

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

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

1 transmission and gas and transmission.

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

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

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

19 MR. YEOMANS: Yeah thanks. I apologize. I don't
20 know how I dropped off, and actually I lost a little time
21 because I thought the problem was the same. But be that as
22 it may yeah, just coming back to what I believe is question
23 three regarding critical gas electric loads and we're all
24 paying attention closely to what happened in ERCOT, what we
25 can learn from that. But quite frankly, in the last five or

1 ten years we have gone to the New York gas company really
2 focused in our states more than once, a couple times, to
3 talk to them about their compressors and motor generated,
4 motor driven compressors versus gas turbine driven
5 compressors.

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

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

23 MR. WHITMAN: Thank you. If there are no other
24 comments I want to ask if the Commissioners have any
25 questions at this time that they would like to ask. If not,

1 we'll go on to our next question.

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

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

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

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

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

1 we're now in fire season again.

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

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

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

24 So you know I'd be happy to you know send some
25 additional information in on that, but that's what I

1 understand is the combination of just a lack of compensation
2 mechanism as well as some sort of technical metering issues
3 that if we could work those out could really make a big
4 difference, and it is going to be critical again this summer
5 we're sure.

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

10 MR. WHITMAN: Thank you. Next Amanda please?

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

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

25 So for instance, you need to have as a retail

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

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

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

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

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

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

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

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

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

25 If we intend to properly compensate a lot of the

1 responses either to intermittent resource output dropping
2 off unexpectedly, or extreme events, or other factors that
3 can threaten reliability, the price we set during the event
4 in real time becomes a critical component of the incentives
5 that you give folks to make the kind of decisions that you
6 want them to make.

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

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

21 And often times the extreme events, or the
22 emergencies happen with only an hour or two notice, or even
23 less than that sometimes. So then you know in a lot of
24 cases we've looked in MISO and the amount of the demand
25 response that they purchased in the capacity market versus

1 the amount they've been able to utilize have been very, very
2 different.

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

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

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

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

21 MR. WHITMAN: Sure.

22 MS. HOSKINS: Oh great, thanks. Yeah, and there
23 are a few things there that I feel like I have to respond to
24 from the demand side. One is that you know when you're
25 working with solar and batteries and aggregating them, which

1 is what we're dealing through virtual power plants, and even
2 through the bid that we made that was accepted in New
3 England ISO a few years ago, is one of the benefits is it's
4 not like typical demand response because we are able to work
5 through the thousand or so units that we've aggregated
6 together, and customers can continue to have access to
7 power.

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

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

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

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

8 There's a very important role for aggregators to
9 make sure that there is the ability to respond to signals,
10 and you know I certainly am hopeful that you know during the
11 2022 process and otherwise that you know people can learn
12 about the opportunities that are out there now with this
13 technology, and we can find a way to make sure that it's
14 really brought into the markets, thanks.

15 MR. WHITMAN: Thank you. Next Renuka?

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

23 So much to Anne's point you know you could design
24 this product for you know it could respond to parties, it
25 could have specific performance expectations and it's a

1 known quantity you get in a known amount of time, so 30
2 minutes, two hours, the entire time.

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

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

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

23 So pushing more demand response into that price
24 sensitive category with the distributed energy resources
25 type products I think is one way. We also should look at

1 how do you improve the demand response that's only available
2 and under emergency condition. You can't eliminate it.
3 Some of it will still be available just because of how the
4 industry works.

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

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

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

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

25 And what we're looking at today is you know

1 terawatts of renewable generation will require gigawatts of
2 flexible energy, or flexible demand. And that flexible
3 demand can really help us respond to certain limited
4 capacity on the transmission system, because distributed
5 energy resources are everywhere.

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

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

19 And I also want to point out that the comment
20 around DR, dynamic demand response today you know, this is
21 not your parent's DR anymore. We're really talking about
22 flexible and nimble resources, which is why I'm super
23 excited to represent you know not just the University of
24 Vermont. I'm not just representing Pacific Northwest
25 National Lab, you know, which has been the first place of

1 transactive energy, but I'm also representing a small
2 startup company in Vermont called Packetized Energy which
3 has a platform for DERs called Nimble, which is really
4 illustrating that DERs today are not the hammer of
5 yesterday.

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

9 MR. WHITMAN: Okay thank you.

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

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

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

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

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

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

20 More often it's going to be the case that we have
21 very specific locations where we're having reliability
22 problems, and congestion that the ability to access those
23 resources will, I agree with you, be extremely valuable, but
24 we're not quite there yet in terms of having enough
25 visibility on where they're located in order to settle with

1 them accurately, which I think is in the best interest of
2 the DERs, and the RTOs.

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

9 But when we start to go short it can be far
10 cheaper than the marginal value of our reserves. So if our
11 prices for example predictably are going to rise from 500 to
12 1,000 to 2,000 to 8,000 dollars, and you have because you
13 can control the DR very specifically and rotate it, you have
14 customers that are willing to respond at let's say 200
15 dollars a megawatt hour, or 300 dollars a megawatt hour.

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

24 And as we head towards a system with more and
25 more intermittent resources and more uncertainty around

1 their output.

2 MR. WHITMAN: Thank you. Robin?

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

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

20 And so of course this is in the early stages,
21 research stage not yet in development. The teams have been
22 working this year, and for the next two years on how can we
23 solve these issues. One of our proposals is
24 really bringing in concepts from the finance and insurance
25 industry into the power industry, and looking at how we can

1 assign risk scores, so that either aggregators or other
2 people who are looking at these different resources can say
3 well I know with some certainty that this resource can
4 provide me what they want, or they would need to be
5 discounted a certain amount.

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

13 MR. WHITMAN: Thank you. Anne next please.

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

24 So I you know, have people take a look at that.
25 But there are also programs in Massachusetts. There's a

1 clean peak program now as well as just the smart incentive.
2 So certainly there have been efforts I think on the part of
3 some states to try to see how can they not only incentivize
4 customers to invest in batteries, but also to make sure that
5 they have asked to participate when needed, but that an
6 additional incentive, or a focus incentive based on location
7 or time.

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

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

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

19 Mr. Patton mentioned a few things about
20 misalignment of market of the incentives for transmission to
21 participate more dynamically, and I also share Commissioner
22 Christie's enthusiasm for learning more about that.
23 Yesterday there was some conversation about the value of
24 increasing transfer capability across interregional
25 transmission, and Ms. Chatterjee, in your pre-comments for

1 this technical conference talked about the value of RTOs as
2 a resilience platform, and the opportunity for improving
3 seams, redispatch and other coordination in a manner that
4 helps to improve reliability and resilience.

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

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

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

22 The transmission system was carrying 40 percent
23 more loading than we had seen, which means the system was
24 capable. We did have a handful of transmission events that
25 we addressed during the February arctic event, but the

1 transmission really supported a lot of power flows going
2 across the system.

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

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

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

24 With regards to you know ISOs an RTOs are market
25 sources non-markets. I'll make a couple of points. First

1 when we are trying to negotiate seams agreements between
2 ISOs and RTOs I think the Commission led the charge many,
3 many years ago I believe in 2004 and 2005 timeframe, that
4 has led to what I would call state of the art coordination
5 between the markets, between PJM, MISO and SPP we have a
6 really advanced mechanism for economic congestion
7 management and support for each other.

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

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

23 Otherwise we are trying to negotiate you know the
24 negotiations to achieve reliability cannot be done without
25 discussions on efficiency and liquidity, and those

1 discussions are taking a really long time. The parallel
2 flow visualization effort that was led by NERC is finally
3 going to give us more transparency to some of the flows on
4 the interregional flows.

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

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

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

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

1 to where we're affecting each other's systems.

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

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

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

24 So maybe making that a mandatory requirement, and
25 so that would be one element of a seams agreement is joint

1 congestion management. The second would be managing imports
2 and exports between neighboring RTOs or non-RTO areas.
3 That's one area where I think there's a disturbing lack of
4 coordination.

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

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

16 MR. WHITMAN: Thank you David. Amanda?

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

25 MR. WHITMAN: Thank you. Commissioner Clements

1 do you have additional comments or questions?

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

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

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

22 And so in those cases, and in our limited
23 jurisdictional reach, are there ways the Commission can
24 nevertheless encourage or incentivize those players to get
25 at some of these concerns? And I would like to hear from

1 market participants as well as others.

2 MR. WHITMAN: Okay.

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

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

17 That said there is no better incentive to be
18 prepared for a storm than very high shortage prices, and
19 exposure to those prices. And in fact what we experienced
20 was that most of the weather issues that we experienced in
21 2021 were not the same weather events -- or weather issues
22 that we experienced in 2011. Why?

23 Because we took you know a lot of actions to make
24 sure that we had address those things that were exposed by
25 our experience in 2011. I expect that you will see us, and

1 others respond to what we learned through the 2021 storm and
2 make changes going forward.

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

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

19 If we know where the capacity on a pipeline is,
20 and we know you know what the prices are then there's the
21 ability to make a market. I think Dr. Patton brought up an
22 important point around the gas trading limitations there.
23 It is insufficient to have to purchase gas for four days
24 going into a major winter event, and in fact we had you
25 know, we saw curtailment to our power plant even on some

1 contracts that we have days before the winter storm even
2 occurred because the gas wasn't going to be available to
3 trade with us during the middle of the storm anyway.

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

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

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

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

25 I think we saw a much bigger problem with public

1 entities than we did with either the competitive retail
2 loads, or the competitive generators. But so I would say
3 rely to the maximum extent on market incentives, then
4 identify the entities that don't have good market
5 incentives. So I mentioned transmission owners a minute ago
6 as being a set of participants you should be concerned
7 about.

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

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

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

25 COMMISSIONER CHRISTIE: Sure. Dr. Patton I'd

1 like to ask you to follow-up a little bit and expand on you
2 said FERC should require RTOs to have seams agreements, and
3 the seams agreement should cover several topics. And I got
4 down congestion and more efficient management imports and
5 exports. Would you elaborate on I think you have some other
6 criteria that you thought should be in the seams agreements?

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

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

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

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

5 COMMISSIONER CHRISTIE: Thank you.

6 DR. PATTON: Uh-huh.

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

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

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

20 You know in our view having a solar battery on
21 someone's house is essentially creating what you might
22 consider a nano grid right? And as we get greater
23 electrification, this is going to really increase both the
24 need for that source of power, that really local source of
25 power, but also the potential as we're able to start

1 connecting these together, as we're starting to see you know
2 the multigrade chargers, other kind of electrification in
3 the home.

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

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

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

23 And you know I heard I think it was Mads earlier
24 talk a little bit about transactive energy and some of those
25 ideas, but really what the idea here would be is you have

1 you know a subset of the homes and businesses in a
2 neighborhood which could actually be fully disconnected from
3 the grid you know, linked to a substation where you would be
4 able to disconnect, not just at the home which we're able to
5 do now in this nano grid, but actually to disconnect a
6 segment of the grid.

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

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

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

22 MR. ALMASSALKHI: Thank you Peter. And thank you
23 Anne for raising really good points around DERs. We are
24 ourselves a very small company, but I think when we go back
25 in Texas we saw some of the practices in place around the

1 rolling blackouts of how to manage certain extreme events.

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

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

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

21 NERC has been really flexible recently in
22 thinking about DERs beyond solar and batteries. And really
23 thinking about demand side loads as also being aggregated
24 and being part of distributed energy resources, which we
25 think that Packetized is a really important step forward and

1 we look forward to seeing that DERs taking a more inclusive
2 term, beyond just batteries and solar. Thank you Peter.

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

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

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

20 We receive a lot of stability by being connected
21 to the eastern interconnection. Having said that, we really
22 think the opportunities are to the extent that we can use
23 PN, or if we think there's extreme weather coming and our
24 neighbors are having disturbances, or extreme weather,
25 there's actually a tremendous amount of benefit again to

1 re-dispatching the electric system to back down the power
2 pole, similar to what we do with thunderstorm alert.

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

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

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

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

25 (Break.)

1 Panel 4: Recovery and Restoration

2 MR. AMERKHAIL: All right welcome back everyone.

3 Let's get started with our fourth panel today entitled,

4 "Recovery and Restoration." I'll turn it over to my

5 moderators, thank you.

6 MR. HENSLEY: Thanks Rahim. I'm Jesse Hensley

7 from the Office of Energy Policy and Innovation. And with

8 me I have Pat Shob also from the Office of Energy Policy and

9 Innovation and we'll be serving as co-moderators. As Rahim

10 mentioned this panel will focus on the recovery period

11 following an extreme weather event, including but not

12 limited to topics such as restoration practices and

13 prioritization, mutual assistance agreements, spare parts

14 inventory and sharing.

15 Six panelists and six questions. We're going to

16 forego opening remarks and move directly into a question and

17 answer session. I'd like to start by introducing our

18 panelists. We have Kevin Geraghty, Chief Safety Officer and

19 Senior Vice President Electric Operations from San Diego Gas

20 and Electric;

21 Daniel Brooks, Vice President of Integrated Grid

22 and Energy Systems; and Charles Long, Vice President of

23 Transmission Planning and Strategy, at Entergy; Michael

24 Bryson, Senior Vice President of Operations at PJM, Brian

25 Slocum, Vice President of Operations from ITC Holdings, and

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

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

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

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

23 And question one is what are best practices for
24 restoration, including for determining appropriate
25 prioritization of load restoration, mutual assistance

1 agreements, and spare parts inventory and sharing? And then
2 how should these best practices evolve given the increasing
3 frequency of extreme weather? So Jodi all yours.

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

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

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

22 And then I'll fast-forward until August of last
23 year, August of 2020 where Tropical Storm Isaias hit our
24 service territory. We lost about 575,000 customers in that
25 storm. It was a very quick-moving powerful storm, however

1 within 72 hours 98 percent of our customers had been
2 restored.

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

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

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

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

1 circuits.

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

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

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

23 We also use a tool called ramp up, which enables
24 us to get mutual aid quickly from even outside that region,
25 so we put that in place. That's been helpful. And then

1 third major buck will be communication. And I think that
2 all utilities have seen this over the past decade. The need
3 to how to put in place a multi-dimensional communication and
4 stakeholder engagement plan.

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

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

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

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

1 Michael Bryson.

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

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

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

23 And they're great, but we really having an
24 interconnective system with MISO in New York and Va-Car and
25 TBA, I mean that's really what we're going to lean on in

1 terms of trying to restore the system, and so those are kind
2 of two best practices making sure you're tightly coordinated
3 with your neighbors.

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

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

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

18 We called it a 40 mile wide tornado that was on
19 the ground for a 200 mile stretch. And another way we
20 talked about it was having a category four hurricane hit the
21 corn fields of the Midwest. Just a crazy event for us, and
22 I think it really brings home the point that we're talking
23 about here in this conference, or in this technical
24 conference here where these extreme events seem to be kept
25 happening more often, and then also hitting areas in ways

1 that we've never really seen before.

2 Adam Smith talked about it yesterday too. We had
3 11 billion dollars in damages that were caused not only in
4 our service territory, but our partners in the area as well
5 were part of that damage. And so we certainly learned a lot
6 from that and other events that we've had in the past.

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

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

20 Is making sure we had that standardization so
21 that we can help ourselves out from our other adjacent
22 service territories, and that's exactly what we had to do is
23 take inventory that we had in Michigan, as well as resources
24 from Michigan, and help out there in Iowa. And so I think
25 the other thing is on the supply chain side, we're trying to

1 effectively manage our inventory to make sure that we're
2 able to respond to events like this, but also balance the
3 cost of that inventory.

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

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

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

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

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

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

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

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

23 And while we look to do that as a last resort, we
24 do look to restore those customers as quickly as possible,
25 and I think we've got some best practices that kind of help

1 with that. And I think about it really being three things.
2 And a few you've heard about. Now alter the assets to meet
3 the new challenge they face. You can't wait for retirement.
4 Can't wait for end of life.

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

10 And the one that I would also point to is you
11 have to have world class emergency operations and community
12 engagement. When I think about what differentiates STG&E
13 quite a bit. We have a first of its kind utility
14 meteorological system, so we have more than 20, 220 weather
15 stations across our high fire threat district that provides
16 24/7 real time information on the surroundings our assets
17 are operating in.

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

1 and then spot fires quickly.

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

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

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

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

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

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

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

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

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

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

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

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

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

24 If getting the lights on isn't the top, isn't
25 going to solve the problem, then maybe that's not the top

1 priority. But if you think about how things are going to
2 change in the future, transportation, information,
3 communication, all of those infrastructure sectors are just
4 going to be increasingly dependent on electricity.

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

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

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

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

24 And obviously, doing work to look at how you
25 minimize power to repair the physical damage to the system

1 and I'll save that for the next question that's more focused
2 on that. But looking at how you actually minimize the time
3 to electrically restore service as we get into prioritizing
4 those critical loads, all of those different things.

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

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

21 We've certainly been working with a lot of the
22 utilities and RTO/ISOs on over the last few years and have
23 tools that are being used for that capability. Once you
24 have those black start units, how do you then not determine
25 necessarily the load priorities, but how do you make sure

1 that you are optimally cranking through sequences that get
2 to minimum restoration times for those priority loads?

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

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

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

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

1 something that's really important.

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

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

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

23 So that capability and understanding how to
24 leverage those emerging resources into the restoration plans
25 I think would be very important as we go forward and as our

1 resource mix changes. And I'll stop there. I have some
2 other things on mutual assistance that maybe we'll get to
3 later if there's opportunity.

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

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

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

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

1 communities.

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

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

21 But I will tell you way above and beyond the
22 obvious assets whether it's the structures and the wires,
23 there's so much more to gathering this data, whether it's
24 weather data, camera data, condition data, the satellite
25 information, and we're actually building our own private

1 network to bring all of that data back to our teams to be
2 able to make informed decisions because it's no longer about
3 skating, know the condition and operations of your system,
4 you have to have complete awareness of the environment that
5 it's operating in.

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

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

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

25 MS. MOSKOWITZ: It would help if I took myself

1 off of mute. Okay. Here I am. I wanted to just kind of
2 quickly double back to a point that I touched on in response
3 to question one as it pertains to how we're designing our
4 substations. And I mentioned the extreme flooding
5 conditions that we found ourselves in during super storm
6 Sandy.

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

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

22 And if we had not raised it, we have 5,700
23 customers directly connected to that substation and all of
24 those customers would have lost power and none of them did
25 because of the way that we hardened the substation. So I

1 want to give that as an example of how we sort of
2 proactively incorporated these flood, FEMA design
3 requirements into our stations and that has reaped benefits
4 for our customers.

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

8 MS. MOSKOWITZ: Yes, yes.

9 MR. HENSLEY: Okay.

10 MS. MOSKOWITZ: It was.

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

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

22 Another thing is to make sure you have
23 pre-determined evacuation plans for employees, equipment and
24 materials that are going to be critical to the restoration.
25 You know having your employees or equipment impacted by the

1 events such that they can't engage in the restoration is
2 obviously not somewhere you want to be, so pre-plan that, so
3 you know where you're going to evacuate those people and
4 materials to.

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

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

21 And then Mr. Bryson talked about the value of
22 that one tie on and I completely agree. The first lights
23 that were on at Lake Charles after Laura were actually lit
24 from a tie line. They weren't lit from a black start
25 generator. And even for Laura where we saw winds on the

1 coast of Louisiana at 150 miles an hour, our newest designs
2 and transmission lines didn't survive.

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

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

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

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

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

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

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

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

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

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

25 MR. HENSLEY: Thank you Mr. Chairman. I think in

1 the interest of complements I think there's a lot of
2 interest in three and six, I'm going to turn to those.
3 Question three is should restoration capabilities be
4 improved by encouraging planners, governmental authorities
5 and utilities to require dual fuel capability in all black
6 start units?

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

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

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

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

1 valuable.

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

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

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

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

23 Fuel delivery infrastructure can be improved
24 probably you know more efficiently in some cases to where
25 the infrastructure to deliver the fuel is just more

1 reliable. And then one of the things that we found to be
2 very, very valuable is onsite fuel storage.

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

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

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

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

1 But even given that loose definition of those 150
2 units I talked about, we have about 50 percent that I call
3 fuel secure. The interesting thing is the hurdle to get to
4 100 percent fuel security is about 150 million dollars for
5 the system. And the hurdle to get to just making sure every
6 TO zone is fuel secure is about 20 million.

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

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

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

25 It is not subject to the same type of extreme

1 cold weather variables as other types of generation, where
2 gas supplies can freeze, or coal supplies can freeze, and it
3 also has the benefits of promoting the clean energy future
4 that we all want. But I did want to emphasize we're talking
5 about resilience and fuel security, the important role, the
6 critical role that nuclear is going to play going forward.

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

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

25 MR. HENSLEY: Okay thank you. Kevin Geraghty I

1 believe you're next.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

25 And then obviously, as it evolves, the

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

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

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

17 MR. HENSLEY: Thank you. That's a great point.
18 I think I did see Michael Bryson if you would like to be the
19 last one to weigh in on this question four, then we'll have
20 10 minutes left for our question five, thank you.

21 MR. BRYSON: Yeah thanks Jesse. Just really
22 quick. You know Brian talked about that you know kind of
23 getting feedback from stakeholders and education. I think
24 managing that expectation with stakeholders and states up
25 front is important, particularly because when you look again

1 at that difference between a black start system restoration
2 and an extreme weather event system restoration because
3 those expectations are going to change, and so putting some
4 time in the up front work is really important.

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

7 DR. BROOKS: Hey Jesse just one comment quickly.

8 MR. HENSLEY: Oh sure.

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

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

22 MR. HENSLEY: Thank you. My apologies for
23 missing your hand there. Last question is question five and
24 it looks like we have about eight minutes to answer it.
25 Question five is can innovative mitigation strategies such

1 as controlled sectionalized or islanding employed during the
2 operating day to improve resilience and reduce the loss of
3 the load, also help to ensure more timely restoration of
4 services to loads that are lost in an extreme weather event?

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

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

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

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

24 The thing that we run into oftentimes when we
25 take projects in through the RTL planning process is the TPL

1 standards are seen as this is what you're to plan to. And
2 when we bring a project that says we want to pull a line
3 from a different location, a backup line for resiliency, or
4 even in a routing.

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

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

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

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

1 you may have transformer dependencies.

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

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

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

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

1 able to identify those critical loads.

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

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

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

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

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

1 especially veg management, thank you.

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

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

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

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

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

24 DR. BROOKS: I'll jump in Brian and just say that
25 I agree completely with Jodi. And my comment wasn't

1 intended to say that we need to be looking at how we can you
2 know intentionally island an entire system during a
3 restoration event. I think there's targeted opportunities
4 to increase the resilience of critical loads even with the
5 more macro investments that are required, and that was my
6 comment.

7 MR. HENSLEY: Thanks again. At least on my clock
8 I see that we're about at the 4:20. It seems like a good
9 place to stop. I want to really thank all of the panel four
10 people for participating today. We're going to take about a
11 20 minute break and then reconvene at 4:40 with panel five.

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

16 (Break.)

17 Panel 5: Coordination

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

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

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

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

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

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

25 Welcome panelists. As we begin I'd like to

1 remind you to refrain from any discussion of pending or
2 contested proceedings. If anyone engages in these types of
3 discussions my colleague, Michael Haddad from the Office of
4 the General Counsel will interrupt to ask the speaker to
5 avoid that topic.

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

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

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

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

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

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

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

23 I'd also highlight in some of the myriads of
24 comments that they submitted that this really sort of comes
25 out of Congress's desire to acknowledge the dual roles that

1 both the states and FERC have and as they noted there may
2 not be a better example of issues that should be addressed
3 by a multi-jurisdictional, multi-pronged collaborative
4 approach than those related to climate change and extreme
5 weather events that have an impact on local and general
6 electric systems.

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

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

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

25 I know other states, you know, with a host of

1 recommendations across electric and natural gas coordination
2 of the two and propane and cyber and physical security and
3 emergency response, I know other states Mississippi is in
4 the process of doing something after the February event, and
5 other states have done similar things.

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

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

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

22 It was quite devastating. And the ability to
23 coordinate and put boundaries and activities around how you
24 communicate those PSTS events and how long the durations and
25 the advanced edification as we see PSTS events now expanding

1 throughout the west as a potential tool to address wildfire
2 risk in some of these climate change activities, so it would
3 just be one example of several that I think having FERC in a
4 coordinated role with state-type regulations would be very
5 beneficial.

6 MS. WHITE: Thank you. Commissioner Tawney?

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

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

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

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

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

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

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

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

21 MS. WHITE: Thank you. Mr. Terry?

22 MR. TERRY: Thank you. I also want to commend
23 FERC for raising these issues and the topics today and I
24 think Chair Scripps has said it well. A couple of
25 additional items I would add. I think the visibility issue

1 that was just raised is an important one across multi-state
2 jurisdictions, and really the changing nature of the grid
3 generally.

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

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

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

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

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

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

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

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

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

25 And I think you know, any coordination or best

1 practices in cost recovery of grid hardening, and recovery
2 of such plans could be helpful. You know and then again you
3 know helping with regional transmission expansion which
4 we're going to need for resiliency as we've seen in Texas,
5 to respond to these climate change events.

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

11 MS. WHITE: Thank you and Secretary Hoffman?

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

19 I guess what I wanted to emphasize is really what
20 should be the goals and focus of the coordination as part of
21 the question. And I think we really have to take a
22 risk-based approach with investing and building blocks which
23 was already discussed, the visibility, the data, and the
24 transparency so that we actually could have a coordinated
25 conversation of what infrastructure investments are required

1 to mitigate climate change and security risks facing our
2 nations.

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

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

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

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

25 MS. MEYER: Commissioner Tawney I see your hand.

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

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

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

1 outcome.

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

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

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

1 MS. WHITE: Ms. Barbash?

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

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

15 MS. WHITE: Chair Scripps?

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

24 But being able to then rely on what's been done
25 in the west when we have those events. We're taking the

1 vast and unfortunate expertise that we have with winter
2 weather in Michigan, for when those events strike in Texas
3 and the south where maybe they don't have those, you know,
4 but in terms of how we approach weatherization of lines in
5 the generation assets and the like.

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

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

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

1 MS. WHITE: Thank you. Mr. Terry?

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

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

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

24 So I do think we have to approach risk in a
25 different way, and I guess quickly, one thing we've learned

1 on emergency preparedness and response with the energy
2 offices over the last several decades to state the obvious,
3 those states that have experienced a lot of hurricanes or
4 wildfires I think have a much better feel for how to address
5 and work with this issue across borders within their own
6 states.

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

14 MS. WHITE: Thank you. Ms. Wayland?

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

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

1 within the FERC jurisdiction.

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

4 MS. WHITE: Secretary Hoffman?

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

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

21 MS. WHITE: Mr. Howard?

22 MR. HOWARD: Yeah I want to echo other people's
23 comments. I concur with many of those. What I find is
24 industry in the electric sector is very good at sharing. We
25 share lessons learned quite often, whether they're publicly

1 on the utility, an investor on the utility, or a rural
2 electric, I mean we don't seem to have a lot of boundaries
3 there in sharing information through a lot of our different
4 professional organizations.

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

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

22 You know you have the standards under which we
23 can remove it outside and we're built for these types of
24 activities. And so what we find is more of the standards
25 that are in place today become bigger barriers for us to

1 recover quickly and move on to prepare for the future, and
2 so yeah I'm just challenged sometimes with historical
3 standards that are used, and how we're moving in some of
4 those events in the current climate we are working in.

5 MS. WHITE: Thank you. Commissioner Tawney?

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

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

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

25 MR. SCRIPPS: I guess in the interest of getting

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

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

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

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

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

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

22 And so starting to think about how those new
23 technology applications provide resilience on the
24 distribution grid, you know, that's not FERC jurisdictional,
25 but it certainly gets into the issue of if transmission

1 which is -- and again, that probably goes back to question
2 one, overlap and the need for dialogue on these cross
3 jurisdictional issues.

4 MS. WHITE: Thank you. Secretary Hoffman?

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

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

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

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

6 MS. WHITE: Thank you, Commissioner Tawney.

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

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

23 And I don't have necessarily good answers for
24 that. The utility has made their design efforts, they have
25 hired their experts, and I think regionally when I think

1 about the west there is a way in which this climate impact
2 is going to unfold across the west through the Rockies and
3 the Great Basin, and we need to be talking to each other and
4 tapping national level resources to understand what it is
5 we're even planning to.

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

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

18 MS. WHITE: Thank you. Mr. Howard?

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

24 And using wildfires we had a situation where five
25 of our employees lost their homes, and many more families

1 were evacuated from their homes due to wildfires coming
2 through the areas, and really at that point you can't really
3 on that staff. That staff needs to address the critical
4 needs of their own family in getting their family to a safe
5 location.

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

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

19 MS. WHITE: Thank you. Mr. Terry?

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

25 Florida is a great example. The last major

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

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

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

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

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

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

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

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

24 And then lastly, how is it all being paid for?
25 You know again, it's a multi-jurisdictional asset. We are

1 hardening the distribution grid and the transmission grid,
2 and to the extent that there's multi-beneficiaries, what's
3 the best process for recovery of this?

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

6 MS. WHITE: Thank you and Chair Scripps?

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

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

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

25 MS. WHITE: Okay. Oh sorry.

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

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

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

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

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

23 MS. WHITE: Commissioner Tawney?

24 MS. TAWNEY: Well thank you for the question, and
25 I appreciate that you're listening even as you're on the

1 road. We're all stretched so unbelievably thin as we tackle
2 all these challenges. So I really appreciate the challenge
3 that you have, that FERC staff faces in grappling with all
4 of this.

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

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

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

23 If it take you four years and you're on a four
24 term cycle for your vegetation plan, you've got to determine
25 for where vegetation is going to be, you know, I'm already

1 having a wildfire challenge, you know it can't take four
2 years to absorb a change in what needs to be trimmed, or to
3 adapt to changing tree mortality for example.

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

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

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

25 And we have some of the largest, longest duration

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

5 MS. WHITE: Thank you. Mr. Howard?

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

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

18 MR. WHITE: Chair Scripps?

19 MR. SCRIPPS: I agree with a lot of what
20 Commissioner Tawney said, not surprisingly, but I want to
21 sort of expand on two of the points and then add one. I
22 totally agree. I think if we knew the answer here we would
23 sort of that would be the answer. And so we've got to
24 provide some space for experimentation and innovation, and I
25 think that incentives can play a role in that to figure out

1 what are the right technological fixes that rises to the
2 top when different approaches are tried.

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

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

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

24 By the time we impose a rule on our utilities,
25 you know, that cyberthreat is six generations in the past,

1 and so instead we've used things like DOE C2MT
2 self-assessment tools, and just keep asking questions. And
3 that sort of process based approach as opposed to a
4 standards based approach, particularly in sort of
5 fast-evolving areas I think has you now applicability here
6 to.

7 MS. WHITE: Thank you. Ms. Wayland?

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

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

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

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

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

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

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

20 MS. WHITE: Thanks and Mr. Terry?

21 MR. TERRY: I think it is obviously a great
22 question. I agree with what's been said. I think one of
23 the elements that might be helpful in parallel to this,
24 obviously no regrets items that need to occur on an
25 expedited basis, but I think there's also an educational

1 component for the non-energy state and local leaders,
2 non-energy business community leaders.

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

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

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

21 MS. WAYLAND: Yes there are lots of
22 opportunities, but it turns out not to be so easy to do that
23 kind of cross agency coordination. There are at least 20
24 different agencies that have some oversight into the energy
25 system and even if we just look at the electricity sector

1 it's a large number, you know, everything from Bureau of Rec
2 and how much water do they have in their reservoirs, to the
3 permitting processes that happen across the agencies, the
4 data that's available at NOAA for forecasting and the
5 National Labs.

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

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

18 MS. WHITE: Thanks Mr. Howard?

19 MR. HOWARD: Yes. I'll just touch on one of
20 those types of activities that I think has been successful.
21 I co-chair a wildfire working group in the electricity
22 subsector coordinating council, and I co-chair with a CEO
23 from the investment and the utility and a CEO from the rural
24 electric, and we directly meet with federal agencies to talk
25 about mitigation activities on the front end on how we could

1 mitigate wildfire risk and what parts of the measures need
2 to be changed from the vegetation management to other
3 things, to what do we do when we're in the midst of a
4 wildfire and the coordination or distinction of that fire as
5 quickly as possible to the recovery and the rebuilding at
6 the back end.

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

14 MS. WHITE: Thank you. Chair Scripps?

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

25 And then sort of relatedly, it needs to be

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

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

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

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

1 forward basis.

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

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

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

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

21 It's also very important to have a consistent
22 method for these NEPA processes, so they can't be questioned
23 later -- an expedited process for it in the world we're
24 dealing with now. We can't decide we need transmission and
25 then take 10 years to build it. That's just not an option

1 right now when we're trying to get reliable dispatch of
2 renewables, access to renewables, it can't take that long.

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

10 MS. WHITE: Commissioner Tawney?

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

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

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

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

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

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

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

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

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

18 MS. WHITE: And Mr. Terry?

19 MR. TERRY: Thank you. I think this is one of
20 the more important questions I thought from a state energy
21 office perspective. We have I think a great foundation of
22 federal coordination to build on with the Department of
23 Energy, your office and also some electricity in the
24 emergency response, and to an extent mitigation space to
25 build from, the collaboration there across agencies and fuel

1 types have been I think having seen it go from very limited
2 two decades ago to what we have now, maybe that perspective
3 that the bar seems maybe better than people think.

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

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

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

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

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

1 closing remarks.

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

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

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

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1 CERTIFICATE OF OFFICIAL REPORTER

2

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

6 Name of Proceeding:

7 Technical Conference to Discuss Climate Change,
8 Extreme Weather and Electric System Reliability

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15 Docket No.: AD21-13-000

16 Place: Washington, DC

17 Date: Wednesday, June 2, 2021

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

22

23

24 Larry Flowers

25 Official Reporter