UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Climate Change, Extreme Weather,	**)**	
and Electric System Reliability	**)**	**Docket No. AD21-13-000**

COMMENTS OF 350 NEW ORLEANS, CLIMATE + ENERGY PROJECT, NATURAL RESOURCES DEFENSE COUNCIL, ROCKY MOUNTAIN INSTITUTE, SIERRA CLUB, SUSTAINABLE FERC PROJECT AND UNION OF CONCERNED SCIENTISTS

Pursuant to the Federal Energy Regulatory Commission's (Commission) March 15, 2021 Supplemental Notice of Technical Conference and Inviting Comments (Notice),[1] the Public Interest Organizations (PIOs)[2] hereby submit the below comments. We commend the Commission for undertaking this effort, and greatly appreciate the opportunity to submit comments on these important issues. Given the short time frame provided for this initial input on such a wide scope of issues, the PIOs look forward to the opportunity to provide more in-depth comments following the technical conference.

The responses provided to the questions posted in the Notice address the wide range of challenges facing the electricity sector from climate change and extreme weather events. Below is a summary of the key points made within these responses, which we urge the Commission to address in the upcoming technical conference.

- While the electricity sector prepares to address the threats of extreme weather events, it must also continue to decarbonize to reduce the probability of climate change-related weather patterns.

[1] Supplemental Notice of Technical Conference Inviting Comments, Docket No. AD21-13 (Mar. 15, 2021).

[2] 350 New Orleans, Climate + Energy Project, Natural Resources Defense Council, Rocky Mountain Institute, Sierra Club, Sustainable FERC Project, and Union of Concerned Scientists.

- The current resource adequacy paradigm will require a fundamental re-evaluation to address changes in both the resource mix and patterns of demand.

- Transmission planning that holistically addresses the needs of a largely renewable and more geographically distributed resource mix will be a cost-effective means to provide needed resilience and catalyze the decarbonization of the electric grid.

- Particular attention should be paid to those communities that are the most vulnerable to climate change and the impacts on electric grid reliability, many of whom have also been overburdened by the pollution and other negative impacts from the electricity sector.

- Distributed energy resources, especially electric vehicles, along with greater demand-side participation and energy efficiency measures are all key components to providing resilience at a net economic benefit, rather than solely adding costs.

II. RESPONSES TO QUESTIONS

Below are responses to the specific questions posed in the Notice, covering Questions 1 – 11, 14, 15, 17, and 18.

1. What are the most significant near-, medium-, and long-term challenges posed to electric system reliability due to climate change and extreme weather events?

There are a variety of challenges facing the electric system that may result from extreme weather events. First, are the direct reliability threats to each component of the power system:[3]

Fuel:

[3] Adapted from: *Reimagining Grid Resilience*, Exhibit 4, Rocky Mountain Institute, 2020, available at:https://rmi.org/reimagining-grid-resilience-in-the-energy-transition/

- *Traditional/Thermal*: Extreme weather and natural disasters can adversely impact transportation systems and disrupt diesel and coal supply chains. Persistent cold weather can freeze coal piles, cause freeze-offs of natural gas pipelines, and/or result in gas being unavailable for generators because it is prioritized for heating.
- *Renewable*: Renewable resources are by nature variable, but "droughts" of wind, solar or hydroelectric resource across large geographic areas or that last for days or longer time periods are risks that grow in significance as the quantity of renewables increases.

<u>Generation Infrastructure</u>:

- *Traditional/Thermal*: Thermal plants cannot function if there isn't a sufficient supply of cooling water as a result of the rising temperature of surrounding rivers, lakes, and coastal waters. Inadequate winterization in regions that don't frequently experience freezing temperatures can lead to outages at gas, coal and nuclear plants.
- *Renewable*: Blade icing dramatically reduces wind generation output, and snow can cover solar panels. Extreme temperatures and high winds can cause wind turbine cut-outs. Because of their distributed and exposed nature, wind and solar generation are vulnerable to damage by extreme weather (very high winds and lightning) but the impacts may not be as widespread as outages of thermal plants.

<u>Transmission:</u> Transmission lines and towers are susceptible to extreme weather and natural disasters (e.g., high winds and wildfires). These impacts can cascade, such as when high heat combined with strong wind causes or worsens wildfires.

<u>Distribution</u>: Above-ground distribution lines and poles are highly susceptible to damage as they are the most geographically distributed components of the electricity system.

<u>End-users</u>: Extreme weather events can displace end-users, reducing the amount of load to serve but also creating a need to meet customers' basic needs through community centers or other places of refuge.

A second challenge is developing an analytically sound understanding of the risks and uncertainty of future conditions. A key component of improving this analytical capability is to recognize that reliance on historical weather patterns to predict future conditions is becoming less and less valid as climate change accelerates. All entities involved in electric system planning must incorporate research on climate change and its impacts being conducted by federal agencies such as National Oceanic and Atmospheric Administration (NOAA), and other international and academic institutions.

Third, climate change impacts must be mitigated through the rapid transition to a zero-carbon resource mix and an acceleration of electrification. The severity of ongoing and future impacts of climate change will depend on how quickly we are able to reduce greenhouse gas emissions.[4] Reducing market, operations, and planning barriers to decarbonization should therefore be a top priority.

The need to simultaneously analyze and plan for extreme weather events while accelerating decarbonization requires an unprecedented level of sophistication and coordination among different entities to understand both the risks and uncertainties posed by climate change and the opportunities and business case for responsible and well-informed investments in the electricity system. Establishing these connections and coordination frameworks, building the technical skills across the electricity sector and establishing the practices and protocols for responsible decision making, both in terms of system operations and responsible investment decisions, will all be significant challenges going forward.

An industry-accepted and robust understanding of “resilience” will be needed to inform decision making and investments. But these decisions must also recognize that investments that would perpetuate significant greenhouse gas emissions from the electricity sector exacerbate the risks of climate change and therefore do not fit the definition of resilience.

Fourth, the planning and investments needed to address extreme weather events must maximize the benefits to consumers while minimizing unnecessary costs. It is important to

[4] See *Fourth National Climate Assessment*, Overview, available at: https://nca2018.globalchange.gov/chapter/1/

realize that most of the US has dispatchable capacity well in excess of reserve margins even without considering the important contributions of wind and solar resources.[5] Unfortunately, the two regions with the lowest capacity relative to peak load are California and Texas, where recent generation-related outages occurred. Therefore, in the near-term, it is essential to ensure that existing resources perform as expected (and as generators are compensated) rather than assuming that more capacity is required.

In determining infrastructure investments, attention must be given to the needs of communities that are the most vulnerable to the impacts of climate change and to the infrastructure needs of these communities to build and maintain resilience to climate change. The US Government Accountability Office (US GAO) recently pointed out that "power outages can disproportionately affect vulnerable populations that rely on continued electricity service to address certain health conditions. In addition, low-income groups are more vulnerable to events such as heat waves, given their limited ability to meet higher energy costs and invest in measures to minimize the impact of outages, such as backup generators."[6]

While evaluating and planning for all of these challenges, it will be essential to reexamine the long-standing resource adequacy paradigm, as discussed further in response to question #6.

2. With respect to extreme weather events (e.g., hurricanes, extreme heat, extreme cold, drought, storm surges and other flooding events, or wildfires), have these issues impacted the electric system, either directly or indirectly, more frequently or seriously than in the past, and if so, how? Will extreme weather events require changes to the way generation, transmission, substation, or other facilities are

[5] *Cutting Carbon While Keeping the Lights On*, Rocky Mountain Institute, 2021, available at: https://rmi.org/insight/cutting-carbon-while-keeping-the-lights-on?utm_source=twitter&utm_medium=social&utm_campaign=report_cc&utm_content=partner.

[6] *Electricity Grid Resilience: Climate Change Is Expected to Have Far-reaching Effects and DOE and FERC Should Take Actions*, US Government Accountability Office, March 2021 at 20, available at: https://www.epw.senate.gov/public/_cache/files/3/4/34c92d5c-373c-41cf-b33d-77546c747c36/C1287CE4AD0183E22111F1CFF1D734C5.gao-report-electricity-grid-resilience.pdf.

designed, built, sited, and operated?

Extreme weather events – especially relating to extreme heat events - are directly and indirectly impacting the electric system at a greater frequency and more significantly than in the past. For example, the US GAO recently provided examples of extreme weather events over the past four years that caused power outages for millions of people,[7] including the extreme cold weather in Texas and other parts of the south in February 2021; an extreme 2019 heat wave in the Northeast; Hurricanes Irma and Maria in Puerto Rico in 2017 – causing the longest blackout in US history; and Hurricane Harvey in Texas in 2017. Moreover, Hurricane Sandy disrupted power to over 8 million customers in 2012.

These more extreme weather patterns will require a new risk analysis and investment framework for how generation, transmission, substation, or other facilities are designed, built, sited, and operated. But such changes must be implemented thoughtfully and informed by the best available science on how the frequency, duration, and intensity of extreme weather events will evolve with climate change and the market, operations, and planning changes needed to mitigate the risks to the system.

3. Climate change has a range of other impacts, such as long-term increases in ambient air or water temperatures that may impact cooling systems, changes in precipitation patterns that may impact such factors as reservoir levels or snowpack, and rising sea levels among others. Will these impacts require changes to the way generation, transmission, substation, or other facilities are designed, built, sited, and operated?

In addition to extreme weather events, climate change will have a significant effect on weather patterns, including ambient air and water temperatures, precipitation patterns, and others that will affect both supply and demand for energy. As weather patterns change, so will the performance of wind, solar, and hydroelectric resources that we will increasingly rely on as we

[7] *Electricity Grid Resilience: Climate Change Is Expected to Have Far-reaching Effects and DOE and FERC Should Take Actions*, US Government Accountability Office, March 2021, available at: https://www.epw.senate.gov/public/_cache/files/3/4/34c92d5c-373c-41cf-b33d-77546c747c36/C1287CE4AD0183E22111F1CFF1D734C5.gao-report-electricity-grid-resilience.pdf

decarbonize the electricity supply. As we build a better understanding of future weather patterns and the technology to predict near and long-term weather in a changing climate, robust methodologies will also be needed to correlate changing weather patterns with planning for and the operation of resources whose performance is dependent on those weather patterns. As stated in response to question #1, all of this will require a much closer level of coordination between electric sector players and the best available science from federal agencies, and international and academic institutions.

4. **What are the electric system reliability challenges associated with "common mode failures" where, due to a climate change or extreme weather event, a large number of facilities critical to electric reliability (e.g., generation resources, transmission lines, substations, and natural gas pipelines) experience outages or significant operational limitations, either simultaneously or in close succession? How do these challenges differ across types of generation resources (e.g., natural gas, coal, hydro, nuclear, solar, wind)? To what extent does geographic diversity (i.e., sharing capacity from many resources across a large footprint) mitigate the risk of common mode failures**?

The evolution of the US grid as a one-way value chain from primary fuel to end-use consumer has reinforced a "top-down" resilience paradigm that reinforces cascading vulnerabilities and common-mode failure risk within the power system. As a consequence of this design paradigm, a failure of any component of the grid, from fuel delivery to generators to local distribution lines, can result in disruption of service to end-users. It is only possible for consumers and businesses to receive value from the electricity system if all of the components of the power system and the connections between them function properly. Disruption at a sufficient scale of any one component of the power system, or any single critical connection between components, precludes the ability of end-use consumers to use electricity to deliver valuable services.[8]

[8] *Rocky Mountain Institute 2020,* Chapter 2

The grid value chain that was developed over the past century is vulnerable at multiple critical failure points and delivers value to consumers only if none of those failure points are disrupted at a sufficient scale. Current approaches to mitigate grid security risks generally focus on addressing threats within, not across, each component, and thus reinforce cascading vulnerabilities within the grid.

Resource adequacy planning is typically based on statistical models that consider outages of traditional resources as uncorrelated. These models fail, sometimes dramatically, in the face of common mode failures. In a common-mode event, statistical variables that tend to be mostly independent (like the performance of separate generators) become suddenly correlated.

Across the country, many of the most challenging operational days in the last decade resulted from external causes forcing multiple simultaneous outages. The natural gas system has proven to be particularly vulnerable to this phenomenon.

To state the obvious, wind and solar are both dependent on the weather, and so intrinsically have a common factor determining output across many resources. Because common mode performance is a daily fact of life for these resources, planners have long accounted for these factors. Planning for wind and solar is highly empirical—it relies on historical patterns across the resource fleet that capture the effects of correlated low output or outages. Thus, many common mode failures within the wind and solar fleets are likely to already be well handled with existing planning processes. Common modes between renewable and non-renewable resources remain an undermanaged risk, however.

Geographic, resource, and supply diversity can ameliorate the challenge of dealing with common mode failures. The question is what analytical approach should be taken to evaluate the benefits of diversity. To some degree, diversity is represented in existing models: for example, fleet-wide historical data for wind and solar will include diversity benefits, and Regional Transmission Organization and Independent System Operator (RTO/ISO) planners routinely include diversity factors to reflect non-coincident loads within and between RTOs. Other factors remain inadequately explored: for example, impacts of upstream disruptions in the gas supply are still largely analyzed on an *ad hoc* (and, at worst, retroactive) basis.

There are two main ways to address these problems. The first is scenario analysis, where the model stress tests the grid under different possible common mode events. Anticipating the right scenarios in this analysis has become even more difficult with a changing climate. Additionally, given the complexity and opaqueness of this type of modeling, there is a risk that scenario analysis can reflect commercial interest and conscious or unconscious bias.

The second approach is to focus on end-point service. For example, one can imagine multiple failure paths that might cause power interruption to homes during a cold snap. Instead of anticipating every failure path, the focus is on whether more can be done to insulate homes (metaphorically and literally) so that they are more resilient under many scenarios.

5. Are there improvements to coordinated operations and planning between energy systems (e.g., the natural gas and electric power systems) that would help reduce risk factors related to common mode failures? What could those improved steps include?

Robust coordination between natural gas and electric power systems is still in its infancy but has grown as a priority since the 2011 polar vortex and was brought to light in during the power outages in Texas.[9] Efforts to ensure coordination and communication across those two sectors are essential and should be accelerated.

[9] See for example: *To Fix the Power Market, First Fix the Natural Gas Market*, by James Bushnell, UC Berkeley, *Energy Institute Blog*, March 1, 2021, finding that; "Even outside of Texas though, one of the greatest threats to electricity reliability is the reliability of the natural gas system." Available at https://energyathaas.wordpress.com/2021/03/01/to-fix-the-power-market-first-fix-the-natural-gas-market/

One effort that should continue to be utilized is the Department of Energy's energy assurance planning that identifies interdependencies and vulnerabilities of the different energy sectors, and which involves Federal, state, and local governments as well as the private sector.[10]

Additional areas for improved sector coordination are:

- More work needs to be done to improve visibility across the distribution/bulk power interface so that system operators have a better understanding of what opportunities and challenges are present at the distribution level to improve system performance and inform responsible investment strategies.

- Coordination between the electricity and water sectors is also critical. A July 2020 report by the Energy and Policy Institute describes the conflicts and legal disputes over water that have arisen between communities and the utilities that operate coal plants in the West with increasing scarcity of water.[11]

6. How are relevant regulatory authorities (e.g., federal, state, and local regulators), individual utilities (including federal power marketing agencies), and regional planning authorities (e.g., RTOs/ISOs) evaluating and addressing challenges posed to electric system reliability due to climate change and extreme weather events and what potential future actions are they considering? What additional steps should be considered to ensure electric system reliability?

<u>Evaluations</u>: The current understanding of climate change and its impacts – both in terms of extreme weather events and changing day-to-day weather patterns – is significantly behind what is needed to identify and mitigate growing risks. Climate vulnerability assessments are

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[10] *State, Local, Tribal, And Territorial Energy Assurance -2017 Year in Review*, US Department of Energy, available at: https://www.energy.gov/sites/default/files/2018/03/f50/SLTT%20Energy%20Assurance%202017%20Year%20in%20Review.pdf

[11] *Coal and Water Conflicts in the American West*, Energy and Policy Institute, July 2020, available at: https://www.energyandpolicy.org/coal-water/

becoming more commonly performed by water utilities but are relatively new and uncommon in the electric utility or RTO space.[12] However, there is an increasing recognition across all power sector institutions that the evaluation and analytical methodologies need to improve to better characterize the impacts of extreme weather events and climate change, particularly as the power system becomes decarbonized. Currently the most relevant work in this field remains within research institutions and needs to be leveraged and extended across to practitioners. One known exception on the practitioner space is the Northwest Power and Conservation Council (NWPCC), which has explicitly attempted to incorporate climate impacts into its regional power plans, in part driven by the region's reliance on hydropower.[13]

The Department of Energy has played a leading role in such analyses in the past and should take up that leadership role again.[14] Both the Commission and state regulatory authorities must also play a greater role by encouraging or requiring utility and RTO/ISO assessment of risks and identification mitigation strategies. These assessments must consider the best available climate science and take advantage of scenario-based studies that analyze potential climate impacts under different levels of climate change and paces of decarbonization. The cost of action and inaction must be clearly articulated and informed by the most current and robust science, along with an identification of communities that are the most vulnerable to climate impacts and infrastructure that is most critical to mitigating the risks of climate impacts.

<u>Additional Steps</u>: There are several broad categories of key next steps that should be taken by the electricity sector, especially RTOs/ISOs and utility balancing authorities

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[12] *Climate Change Vulnerability Assessments: Four Case Studies of Water Utility Practices (2011 Final),* US Environmental Protection Agency, available at: https://www.epa.gov/arc-x/water-utility-adaptation-strategies-climate-change

[13] Northwest Power and Conservation Council 7th Plan Appendix M: Climate Change Impacts to Loads and Resources, available at: https://www.nwcouncil.org/sites/default/files/7thplanfinal_appdixm_climchange_1.pdf

[14] A Review of Climate Change Vulnerability Assessments: Current Practices and Lessons Learned from DOE's Partnership for Energy Sector Climate Resilience, May 2016, available at: https://toolkit.climate.gov/reports/review-climate-change-vulnerability-assessments-current-practices-and-lessons-learned-doe%E2%80%99s

A fundamental **rethinking of the long-standing resource adequacy (RA) paradigm is needed.** The current mechanism, in which reliability planning is based on a summer peak demand plus a reserve margin, determined by avoiding a one day in ten-year outage risk, does not meet the needs of a system characterized by increasing variable renewable, storage, and distributed energy resources, while meeting demand that is impacted by extreme weather events and changing weather patterns. These metrics will need to incorporate multiple data points on outage risks (including duration and scope), determine what level of risk is to be avoided, and determine seasonal and intra-day RA reliability needs.[15]

To this point, a recent analysis by Carnegie Mellon University shows the potential benefits of even an incremental shift away from an RA metric based on summer peak demands -- finding that a move from an annual to monthly capacity procurement in PJM could reduce the annual capacity procurement by 16% without increasing the loss of load expectation.[16]

Expanding the regional transmission system and conducting more holistic transmission planning is an essential climate and extreme weather resilience tool. For example, in 2018, the Brattle Group found that by "providing customers access to generation resources with diverse geography, technology, and fuel sources, the transmission network buffers customers against extreme weather events that affect a specific geographic location or some external phenomenon (unavailability of fuel and physical or cyber-attacks) that affect only a portion of the generating units."[17]

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[15] See for example, *Redefining Resource Adequacy for Modern Power Systems*, Energy Systems Integration Group, December 2020, available at: https://www.esig.energy/resources/redefining-resource-adequacy-for-modern-power-systems-derek-stenclik-december-2020/

[16] *Resource adequacy implications of temperature-dependent electric generator availability*, Sinnott Murphy, Luke Lavin, and Jay Apt, Applied Energy, Volume 262, March 15, 2020, available at: https://www.sciencedirect.com/science/article/pii/S0306261919321117

[17] Recognizing the Role of Transmission in Electric System Resilience, The Brattle Group, May 2018, https://brattlefiles.blob.core.windows.net/files/13820_recognizing_the_role_of_transmission_in_electric_system_resilience.pdf

The value of transmission during these extreme weather events should be explicitly taken into account in the calculation of the benefits and costs of new transmission projects. Moreover, transmission can be planned to reduce the need for greater installed capacity and to address the current planned resource mix. As reported by the Americans for a Clean Energy Grid in January, renewable and storage resources made up almost 90 percent of the interconnection queue at the end of 2019.[18] These resources are not dependent upon access to fuel supplies such as natural gas or coal that may be restricted during extreme weather events. A more extensive transmission system will allow better access to such resources, and also ensure that portions of the grid under system stress can import power, especially from the growing renewable resource segment in regions that are not under the same levels of stress.

Electric vehicles (EVs) will also be essential for ensuring resilience, especially under the further development and implementation of bidirectional vehicle-to-grid power, which can provide greater dispatchability of EVs. As transportation electrifies, it will be essential to coordinate vehicle charging other grid demands, including during common mode failures. Coordinated charging can also add resilience by reducing expected demand during shortages or periods of high prices or can be used to flatten peaks. Further incorporation of other distributed energy resources and demand response strategies can be cost-effective resilience tools. Improved building efficiency, smart electrification and demand side management all have significant grid resilience benefits, as documented in a just-released report from the American Council for an Energy Efficient Economy.[19]

7. Are relevant regulatory authorities, individual utilities, or regional planning authorities considering changes to current modeling and planning assumptions used for transmission and resource adequacy planning? For example, is it still reasonable to base planning models on historic weather data and consumption

[18] *Disconnected: The Need for a New Generator Interconnection Policy*, Americans for a Clean Energy Grid, January 2021, available at: https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf

[19] *Demand-Side Solutions to Winter Peaks and Constraints*, ACEEE, April 15, 2021, available at: https://www.aceee.org/research-report/u2101

trends if climate change is expected to result in extreme weather events that are both more frequent and more intense than historical data would suggest? If not, is a different approach to modeling and planning transmission and resource adequacy needs required? How should the benefits and constraints of alternative modeling and planning approaches be assessed?

As noted in response to question #1, it is certainly not reasonable to solely base planning models on historic weather data and consumption trends given the expectation that climate change will alter traditional weather patterns, and future extreme weather events will be both more frequent and more intense than historical data would suggest. Moreover, technology trends such as electric vehicles and building electrification will change load patterns compared to historical norms. Historical data sets provide useful data sets and should not be fully discarded for future system planning but need to be augmented appropriately.

Modeling should be based on different simulated future climate and load profiles using the latest climate science and multiple deployment scenarios for electrification, along with sample extreme case scenarios to stress test planning and operations models. There is a need for ongoing, verified and consistent coincident modeling sets for all core weather variables that impact the electric system.[20]

Contingency plans should be made for certain potential system failures, noting that the question of which system failures to plan contingencies for is a policy decision. Practically speaking, it is not possible to forecast all possible failure events, and to accurately forecast the likelihood of these events, particularly with a changing climate. Noting these challenges, the Australian Energy Market Operator (AEMO) has begun to explore the impacts of climate change on system operations by adopting a "what-if" scenario approach[18] — what if this extreme

[20] These essential variables include wind (across the rotor plane), insolation (direct and diffuse), temperature at the surface and several levels across the rotor plane, pressure, precipitation, soil moisture, and humidity, at a minimum. Such a data set should be at a resolution of a minimum of 2 km, time resolution of 5 mins, and cover the longest period that can be modeled without resulting in an inadequate set of input fields. The dataset should be expanded every month.

weather event occurs due to climate change, what will happen to power system operations? This does not follow traditional power system resource adequacy modeling that uses conventional risk analysis methods and is based on having probabilistic assessments of different failure events (e.g., a generator outage). However, understanding the impacts of events, even in the absence of an exact risk assessment of that event, can help utilities and RTOs plan for such events, even while the ultimate decision about whether to incur the costs of responding to such events remains an important policy question.

Below are some general guidelines for risk analysis, modeling and planning.

- Risks can be divided into three categories: ordinary conditions, extremes, and high-impact common mode events. High-impact commode mode events necessitate a qualitatively different holistic approach to risk mitigation than normal conditions and extremes. These kinds of events tend to be driven by unusual correlation between typically unrelated failure modes that is driven by factors outside the usual scope of consideration. The risk analysis cannot properly be done without considering linkages with other systems, e.g., the gas market, building codes, and water services. Not only should various holistic risk scenarios be developed and explored, but these linkages should also shape investments in mitigation solutions.[21]

- Decision makers need to make plans for managed failure. In the wholesale electricity markets, this might mean public communication and pricing rules under extended outages in multiple circumstances (not just summer peak). For a transmission and distribution utility, this could entail implementing outages while isolating and protecting critical infrastructure as a whole and at individual customer locations. For customer-facing retail utilities, such plans might include an emergency tariff and/or communication plan to provide for rapid conservation and avoid extended exposure to sky-high prices beyond

[21] *Working Paper_Lessons from Texas Big Freeze*, Eric Gimon, Ph. D, Senior Fellow, Energy Innovation LLC, April 2021, available at: https://www.dropbox.com/s/2kqyip41hhca1pv/Working%20Paper_Lessons%20from%20Texas%20Big%20Freeze_EG.pdf?dl=0

what can reasonably hedged or insured financially.[22]

- A robust risk analysis should be accompanied by efforts to identify those communities – either due to geographic location or historical under-investment – that are most vulnerable to climate impacts. Critical infrastructure to maintain community services and safety should also be identified as priority areas for rapid investment.

8. Are relevant regulatory authorities, individual utilities, or regional planning authorities considering measures to harden facilities against extreme weather events (e.g., winterization requirements for generators, substations, transmission circuits, and interstate natural gas pipelines)? If so, what measures? Should additional measures be considered?

Hardening of facilities can certainly enable the grid to withstand extreme weather events, such as the use of steel to repair hurricane-damaged transmission towers in Florida that will allow the grid to better withstand future hurricanes. But it is important to keep in mind that most consideration of hardening is in reaction to an extreme weather event and is not part of a more holistic approach or in consideration of the variety of risks (and the statistical probability of those risks) posed by climate change.

Examining the practice of grid hardening in the context of emerging extreme weather and climate change threats reveals three key insights:[23]

- **Hardening, like other legacy approaches to grid resilience, is limited to addressing risks within specific components of the grid.** For example, transmission grid hardening approaches do not currently provide resilience value in the case of a downstream disruption, as the transmission network requires an intact distribution grid to ensure power delivery to end-use customer loads. Hardening, while having benefits in certain

[22] *Id.*

[23] *Rocky Mountain Institute* 2020, Chapter 5

cases, is thus limited in its ability to address systemic risks; for example, if a common-mode extreme weather failure disables multiple components across the grid value chain, hardening any single component is insufficient to effectively address the systemic issue.

- **Hardening of critical loads should be prioritized in the event of widespread outage.** Hardening should be undertaken to prioritize delivery of available power to the most vulnerable customers or societally critical needs (e.g., medical equipment).

  But hardening should not be treated as a blanket solution to maintaining functionality within the generation or transmission components of the grid without an ability to prioritize delivery of power during an outage.

- **Hardening has limited value outside of contingency events.** Hardening, like "fuel security" measures and other legacy approaches to reliability and resilience, is akin to buying insurance: such measures are only valuable during tail events, and added costs are incurred by grid asset owners, and ultimately customers, outside of contingency scenarios. Conversely, grid modernization investments and other reliability and resilience strategies focused on enabling emerging technologies to provide value during outages can, as part of the same investment, provide economic value during normal operating conditions. For example, grid modernization investments can improve operating efficiency (e.g., reduce line losses) and capital efficiency (e.g., enhance demand response and other DER integration) within the current grid, with benefits increasing as renewable and DER technologies gain market share.

In summary, while hardening components of critical grid infrastructure is likely to be necessary and must be undertaken, such efforts should be prioritized to critical resources and not distract from other, high-value opportunities to improve resilience and reliability in the context of extreme weather and climate change risks.

For example, a number of utilities are implementing strategies that include using DERs to complement the bulk power system in ensuring adequate electricity delivery, especially to critical facilities (e.g., public safety buildings) and loads (e.g., medical equipment within homes), during contingency events. Although outside the scope of the Commission's jurisdiction, FERC's markets and planning rules should maximally account for the full value of these strategies. Examples of such strategies include:[24]

- **Targeted energy efficiency**: Improving passive efficiency for critical loads reduces the energy and capacity required to serve them during any outage. For example, improved building envelopes and high-efficiency equipment (e.g., LED lighting) for hospitals, emergency responder buildings, centers of refuge, and other similar facilities require less electricity to maintain safe internal temperatures.

- **Demand flexibility**: Demand flexibility strategies to change customers' load shapes through various levers, such as timed heating of water in water heaters, timed cycling of air conditioning compressors, timed or grid-responsive charging of electric vehicles, and smart grid-enabled appliances and products that can be subject to utility control as needed. This strategy allows demand to match the production from available power sources, and therefore maximize the utilization of any power generated and delivered during an outage even if the level of available power (e.g., from weather-driven resources like distributed PV systems) is insufficient to meet an inflexible demand profile.

- **Autonomous energy grids**: As defined by the National Renewable Energy Laboratory (NREL), autonomous energy grids (AEGs) can "self-organize and control themselves using advanced machine learning and simulation to create resilient, reliable, and affordable optimized energy systems."[25] AEGs are a broader concept than individual solar-plus-storage systems or microgrids; rather, they are a set of control and optimization tools that can integrate various DER resources to operate "without operators." When the transmission system is de-energized, AEGs can allow for the operation of portions of the grid in islanded or grid-connected mode, enabling portions of the distribution system and connected DERs, to energize using available distributed

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[24] *Rocky Mountain Institute* 2020, Chapter 5
[25] "Autonomous Energy Grids," NREL, https://www.nrel.gov/grid/autonomous-energy.html

generation and provide power to end-use loads. AEGs can allow people to share available power from DERs across physically intact, but otherwise de-energized, portions of the grid, enabling power delivery from distribution-scale resources during an outage.

These and other strategies that use DERs to complement the bulk power system to improve reliability and resilience have several key resilience benefits:

- **Distributed Resilience Interventions Have Value Across Outage Scenarios.** The interventions noted above are located at the distribution or customer level and are able to mitigate failures that occur in all components of the grid value chain. Compared to the mostly upstream impact of existing interventions like hardening, interventions closer to customers have higher impact across more common modes of grid failure.

- **Distributed Resilience Interventions Can Directly Support Prioritization of Critical Loads**. Customer- and distribution-system-sited resilience interventions can directly support prioritization of critical services during a broader disruption. For example, targeted energy efficiency reduces the critical load required for individual critical customers and loads, thus increasing the total number of critical customers served; demand flexibility approaches can prioritize load-shifting activities so that time-dependent critical services are available even during a broader disruption; and AEG deployment can be targeted and/or configured to preferentially support critical customers and/or services, for example by ensuring those loads are equipped with resilient supply and/or are first in line for power recovery after a disruption.

- **Distributed Approaches to Increase Resilience Can Also Provide Economic Value as the Grid Evolves Toward Higher Shares of Renewable and Distributed Resources**. Each of the distributed resilience interventions described here also has the potential to provide value during normal operating conditions in addition to increasing resilience during contingency events. For example, targeted energy efficiency reduces energy use for critical loads, and thereby reduces electricity supply costs at the facility level on a daily basis. Other interventions provide increasing value as the grid technology mix evolves; for example, advanced inverters can help regulate distribution system voltage and mitigate voltage fluctuations driven by increasing rooftop PV deployment, and thus reduce investment in grid infrastructure that would otherwise be required to integrate distributed generation resources.

Implementation of these strategies requires that coordination between communities, utilities, and regional planners must be more robust to identify solutions and risk mitigation measures that are right-sized and meet specific community needs. Localized, community-based, distribution system and bulk electric system investments must be considered in a holistic manner to identify solutions that have the best risk-mitigation potential while meeting other needs of the system such as electrification, decarbonization, and improved reliability. Jurisdictional issues and maneuvering to protect territory or market shares present hurdles to this level of coordination.

9. How have entities responsible for real-time operations (e.g., utilities, RTOs/ISOs, generator operators) changed their operating practices in light of the challenges posed by climate change and extreme weather events and what potential future actions are they considering? What additional steps should be considered to change operating practices to ensure electric system reliability?

RTOs/ISOs and generator operators in the West have by necessity begun to adjust their operating practices to respond to changing weather and precipitation patterns that affect hydroelectric resource performance, extreme heat that stresses the grid, and wildfires that impact both generation and delivery infrastructure.[26] In the east, however, there has been less attention to the impacts of climate change on the real time operations of resources.

Additional steps to consider are: (1) improved short- and medium-term weather forecasting, along with better coordination between system operators and generators to provide

[26] For example, CAISO's Resource Adequacy Enhancement initiative "will explore reforms needed to the ISO's resource adequacy rules, requirements, and processes to ensure the future reliability and operability of the grid." See https://stakeholdercenter.caiso.com/StakeholderInitiatives/Resource-adequacy-enhancements#phase2

greater responsiveness to those forecasts and ensure resource adequacy; (2) better communications and visibility by system operators into the distribution systems they are connected to and the availability of demand-side resources such as flexible load, demand response, and other resources that can mitigate risk. (Also, see response to question #8).

10. Are seasonal resource adequacy assessments currently performed, and have they proven effective at identifying actual resource adequacy needs? If they are used, is there a process to improve the assessments to account for a rapidly changing risk environment such as that driven by climate change? If seasonal resource adequacy assessments are performed, are probabilistic methods used to evaluate a wider range of system conditions such as non-peak periods, including shoulder months and low load conditions?

It has become apparent that resource adequacy risks vary by season. The traditional summer peak risk is driven by high load and reduced output at thermal plants. Summer loads and plant performance are well understood, making this problem generally well managed. Emerging winter risk comes from unexpectedly high loads, correlated weather driven outages, and fuel supply risk. Each of these factors have exceed planners' expectations in recent years, driving some of the most dramatic resource adequacy problems. Finally, shoulder season issues tend to come from high levels of planned and maintained outages combined with surprise loads from unexpected weather.

Seasonal resource adequacy assessments are currently performed, usually focused on either or both winter and summer peaks. But these assessments tend to lag in terms of factoring in changing climate and use mostly historical data. Most processes do not look at a wide enough range of conditions.

However, seasonal assessments often feed into resource adequacy frameworks that are based on annual procurement. Given that load, supply, and risks all vary dramatically with the season, this leads to uneconomic outcomes at best, and at worst creates reliability gaps. In order for seasonal assessments to yield benefits, they must be combined with seasonal assessments of resource availability and be used to drive procurement processes that recognize seasonal resources.

Planning simply for the summer peak is no longer adequate to assure year-round resource adequacy. Seasonal resource adequacy assessments, if accompanied by robust and well-informed analysis, can be an improvement over the status quo, particularly if accompanied by other operational practices such as outage coordination and measures to improve visibility across the system. But this should be just the first step in the evolution towards an hourly resource adequacy assessment that incorporates the best available science behind climate change impacts, probability of extreme weather events, and the anticipated performance of variable resources such as wind and solar that will be increasingly relied upon as we decarbonize the grid.

11. Are any changes being considered to the resource outage planning process? For instance, should current practices of scheduling outages in perceived "non-peak" periods be re-evaluated, and should the consideration during planning of the reserve needs during non-peak outage periods be improved?

Coordinated outage scheduling should become common practice among system operators, as the current practice of scheduling large numbers of outages during off-peak seasons has already resulted in challenging operational situations.[27] Such practices not only improve resource adequacy but are better suited to identifying needs on the system and reducing the possibility of uninformed or unnecessary investments that could be avoided with better coordination. Also, as wind and solar are added, periods of tight resource adequacy will move according to the attributes of the variable resource.

Market treatment of planned outages needs improvement. Off-peak planned outages

[27] For example, in 2019, the Commission approved tariff changes in MISO that provided additional incentives for generator owners to schedule planned outages and derates well in advance of the requested start time and to identify times with increased system risk due to correlation of outages and derates. *Order Accepting Tariff Revisions, Subject to Condition*, Midcontinent Independent System Operator, Docket No. ER19-915-000, March 29, 2019, available at: https://cdn.misoenergy.org/2019-03-29%20166%20FERC%20%C2%B6%2061,236%20Docket%20No.%20ER19-915-000332334.pdf

have long been considered simply a fact of life in the industry, and as a result, capacity markets tend to be quite indulgent of them. Resources typically continue to receive capacity payments while on planned outages, and planned outages are not reflected in resources' UCAP values. Non-performance due to planned outages is readily excused. For example, in the "no excuses" PJM Capacity Performance market, the majority of non-performing resources during the one emergency event occurring to date were excused from any penalties.[28]

The assumptions underlying planning and market treatment of planned outages may no longer hold. With increasing alternatives to thermal generation, it is no longer true that all resources need generous allowances for planned outages and continuing to do so may amount to an unintended subsidy for high-maintenance technologies. Outage allowances based on historical weather and load patterns may no longer be appropriate and failing to update them may again subsidize high-maintenance technology at the cost of reduced reliability. Finally, capacity credits and cost allocation should be closely reviewed to ensure that costs resulting from accommodating outage schedules are not improperly socialized.

14. Given the key role blackstart resources play in recovering from large-scale events on the electric system, how is the sufficiency of existing blackstart capability assessed, and has that assessment been adjusted to account for factors associated with climate change or extreme weather events? For example, is the impact of potential common mode failures considered in the development of black start restoration plans (including but not limited to common mode failure impacts on generation resources, transmission lines, substations, and interstate natural gas pipelines)? Should these be addressed?

There were multiple concerns expressed about whether black start service could be

[28] "PAI Settlements", March 2020 report to PJM MIC, Table 5 and Fig 2, pp8-10, available at https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20200415/20200415-item-08b-performance-assessment-event-settlement-paper-october-2019.ashx

provided in ERCOT, which could take many weeks for system restoration to be achieved.[29] Improvement to the procedures and more R&D is required for black start service, especially if batteries will play a role in the provision of this service. Possibilities for the provision of black start will evolve with the energy transition. For example, large batteries used in electrification of sea and land transport could play a role in bringing energy and power to a crisis location, along with a greater use of microgrids and islanding. Any Commission efforts in this area should allow for an evolving process.

15. What actions should the Commission consider to help achieve an electric system that can better withstand, respond to, and recover from climate change and extreme weather events? In particular, are there changes to ratemaking practices or market design that the Commission should consider?

The Rocky Mountain Institute has established four principles, and associated specific guidance, that can allow the Commission to better align rates and market structures with the emerging risks to and solutions for grid resilience and reliability in the context of extreme weather and climate change:[30]

- **Address, Don't Ignore, Linear Dependence**: Effective resilience approaches should acknowledge and address the linear dependencies that lead to common points of failure, seek to remove the dependencies by creating redundancy below common points of failure, or both. The Commission can pursue rules that focus on incentivize outage prevention and restoration investments as far "downstream" and as close to end-use customers as practical, rather than placing too much emphasis on fuel security, and prioritize scalable resilience solutions that can serve critical loads and services under a

[29] For example, see *Lessons from the 2021 Texas Electricity Crisis*, Working Paper, Peter Cramton, University of Cologne, March 2021: Unlike the systems to the West or East, which can jump-start their production using the Hoover Dam, Niagara Falls, or Direct Current ties of neighboring grids, Texas has no such option. 'Black start' in Texas would be a delicate and lengthy process that would have to start from zero. It would take many weeks to execute." Available at: http://www.cramton.umd.edu/papers2020-2024/cramton-lessons-from-the-2021-texas-electricity-crisis.pdf.

[30] *Rocky Mountain Institute 2020*, Chapter 6.

wide range of outage scenarios.

- **Leverage the Market, Don't Fight It.** Accounting for technological change, in contrast to planning for a static resource mix, can provide a more comprehensive foundation for market design and other strategies to improve resilience. Where markets are helping drive deployment of assets that could improve customer resilience, such as DERs, the policy should be to always allow, and preferably encourage their installation such that these technologies can deliver their potential resilience value.

- **Prioritize Critical Loads**. Rather than focusing on maintaining functionality within each segment of the grid, effective resilience solutions should consider load prioritization to maintain critical services as much as possible and enable targeted restoration plans. The Commission can focus on rates and market structures that incentivize achieving resilience of critical loads (based on economic, health, and safety criteria) to disruption, and avoid a blanket approach that could be costly and less effective.

- **Maximize Economic Value from Resilience Investments**. Resilience investments are not generally justified by cost-effectiveness (because blackouts are costly but historically rare), but there is still societal value in achieving a balance between resilience for as many customers as possible and ensuring manageable costs. It follows that the lower the net cost of a resilience-enabling investment, the more scalable it is in a world with limited capital available for grid investment. To lower the net cost of resilience- and reliability-improving technologies, the Commission can continue to push for widespread, standardized, and seamless integration of DERs into wholesale power markets, so that these resources can earn appropriate revenues for providing economic, reliability, and resilience value to customers and the broader grid.

With regard to the issue of wholesale market design, there are several potential options to consider:

- **Scarcity Pricing/Prudency Requirements.** The potential of high scarcity prices during extreme weather events can lead to investments in mitigating technologies, which can be one tool for improving resilience. While noting that such a pricing mechanism is itself not sufficient to address the preparations needed for extreme weather events, two elements to making this a more effective tool are awareness and accountability. Awareness means that all market participants have a good understanding of the possible price impacts during times of scarcity. Accountability means that all market participants are able to deliver on their commitments during these extreme events such that the scarcity pricing does not only lead to high prices without a benefit to the system. For a regulator this may mean imposing some stricter prudency standards and insurance requirements, which may in turn trigger useful investments.

ERCOT's experience with a three-day maximum pricing event will need to inform scarcity pricing design and demonstrates that a circuit breaker will be needed. The current scarcity pricing framework created a $52 billion gross transfer from customers to generators with no obvious benefits.[31] But at the same time, some scarcity pricing designs may not be sufficient to provide the needed incentives.

- **Non-Performance Penalties/Resource Adequacy Reform.** Another approach is to incentivize investments to mitigate the risk during extreme weather events through stricter performance requirements with penalties and rewards when accredited capacity is not available during times of system stress. One drawback is that such penalties are often tied to the sale or accreditation of capacity "products" as commodities, which prevents consideration of the full range of solutions to extreme events, especially options with multiple benefit streams like weatherization that do not impact capacity availability. As noted previously, revising resource adequacy to incorporate reliability criteria outside of capacity available for peak load allows load-serving entities and grid operators to find creative approaches to reliability needs.

- **Separate Expenditures.** While this is not necessarily a market-based approach, a new

[31] Gimon 2021.

category of revenue collection could be created for market participants (similar to transmission access charges) which funds solutions aimed at mitigating extreme weather events.

17. Where climate change and extreme weather events may implicate both federal and state issues, should the Commission consider conferring with the states, as permitted under FPA section 209(b), to collaborate on such issues?

Yes. Given that multiple restructured and regulated states have been taking actions to address climate change, and that such actions have in some RTOs/ISOs come into conflict with market rules, especially in the capacity markets, greater communications and collaboration between the Commission and the states would be beneficial in developing strategies to both mitigate climate change and to address the reliability impacts of extreme weather. Unfortunately, the Commission has rarely used the provision of section 209(b) for convening state-federal panels,[32] which can provide benefits from establishing a forum for greater collaboration on policies with the potential to minimize future federal-state conflicts. We support greater the Commission's use of this mechanism to promote meaningful on-going collaboration with states on a range of resource adequacy issues, including those relating to extreme weather and climate change events.

III. CONCLUSION

For the foregoing reasons, 350 New Orleans, Climate + Energy Project, Natural Resources Defense Council, Rocky Mountain Institute, Sierra Club, Sustainable FERC Project, and Union of Concerned Scientists respectfully request that the Commission consider these comments.

Respectfully submitted,

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[32] *Moving Forward: Approaches for State-Federal Cooperation in a Decarbonizing Electricity Sector*, Travis Kavulla, NRG Energy, January 2021, available at: https://www.nrg.com/assets/documents/white-papers/moving-forward-approaches-for-state-federal-cooperation-in-a-decarbonizing-electricity-sector.pdf

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