UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF TABORS CARAMANIS RUDKEVICH
APRIL 15th, 2021

We welcome the opportunity to provide comments on the issues raised in the Commission's Notice and Supplement Notice of Technical Conference. Our comments reflect the views of Tabors Caramanis Rudkevich (TCR), experts and consultants Paul Centollela, Mark Gildersleeve, Ira Shavel, Alex Rudkevich, and Richard Tabors who were Principal Investigators in the Electric Power Research Institute (EPRI) project that produced the recent EPRI report, Exploring the Impacts of Extreme Events, Natural Gas Fuel and other Contingencies on Resource Adequacy (EPRI Report).[1] A copy of this report can be found in Appendix A to these comments. The TCR team has extensive experience in power market design and pricing, probabilistic analysis, weather forecasting, and utility regulation. Our biographies can be found in Appendix B.

I. Impacts of Climate and Extreme Weather on Electric System Reliability

Our nation's energy systems are confronting a new reality: the increasing frequency, intensity, duration, and geographic scope of extreme weather events. As illustrated by the February service interruptions in ERCOT, MISO South, and SPP, severe weather can lead to the coincident failure of multiple generating units, significant interruptions of gas fuel supplies, and demand well in excess of seasonal forecasts. The February event is an example of a common mode event, one in which there is a common cause underlying the failure of seemingly independent components or systems.

Our current resource adequacy metrics and planning methods systematically understate the probability, depth, and economic, health, and safety costs of high impact events that significantly increase demand and/or reduce the output of multiple resources.

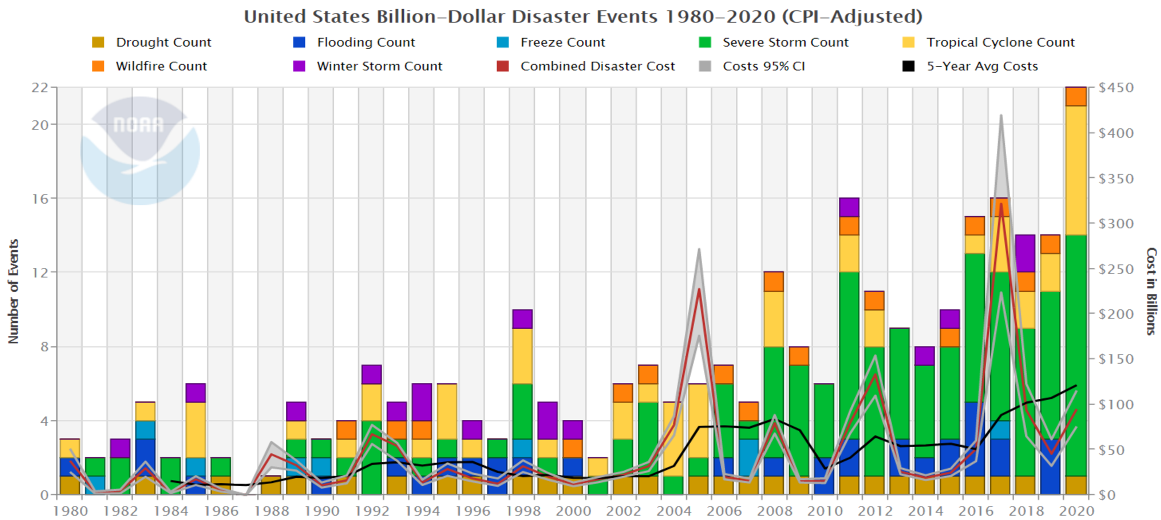
Extreme weather is no longer an infrequent occurrence. The average number of U.S. weather events causing over $1 billion in damages has increased five-fold, from 2.9 per year in the 1980s to 15 such events per year over the last 4 years. The average annual cost of these billion-dollar events has increased from $17.8 billion in the 1980s to $157 billion per year for 2017 – 2019, or 8.6 times the average in the 1980s.[2] Some of the increase in costs may be due to changes in the demographics

1 Centolella, P., M. Gildersleeve, A. Rudkevich, I. Shavel, and R. Tabors (TCR), R.B. Hytowitz, E. Ela, A. Damant, and E. Lannoye (EPRI). 2021. Exploring the Impacts of Extreme Events, Natural Gas Fuel and other Contingencies on Resource Adequacy. Palo Alto, CA: EPRI. The views expressed in these comments are those of the TCR investigators and do not necessarily represent those of EPRI or EPRI personnel who managed or participated in the project leading to this report.

2 NOAA National Centers for Environmental Information (NCEI), "U.S. Billion-Dollar Weather and Climate Disasters," 2021, https://www.ncdc.noaa.gov/billions/

and the wealth of impacted populations. However, after factoring out changes in demographics and property values, we can conservatively estimate that the costs to the U.S. economy of extreme weather events have more than tripled over this period (See: Figure 1).

Figure 1



Source: NOAA U.S. Billion-dollar Weather and Climate Disasters – 2020

Mounting annual damage costs have coincided with more frequent extreme weather events and a much faster increase in their intensity and geographic scope.

It would be prudent to assume that the trend of increasing frequency and severity of extreme weather could accelerate in future. The globe is experiencing conditions outside the range of modern human experience. The National Oceanic and Atmospheric Administration (NOAA) reported that the annual average global atmospheric concentrations of carbon dioxide (CO_2) reached 412.5 parts per million (ppm) in 2020.[3] Earlier this month, NOAA's Mauna Loa Observatory reported a record daily CO_2 concentration of above 421 ppm.[4] Before 1900, long-term atmospheric concentrations of CO_2 had not exceeded 300 ppm in the prior 800,000 years.[5] (See: Figure 2.) Despite international agreements, the rate of increase in atmospheric CO_2 levels is not declining. The average atmospheric concentration of CO_2 has been increasing by approximately 2 ppm per year.[6] (See: Figure 3.) In 2020, concentrations rose by 2.6 ppm. Given the risk and uncertainty associated with the increase of greenhouse gases in the atmosphere, planners should consider extreme weather scenarios that are more severe and costly than those encountered to date.

We will describe extreme weather trends in greater detail in our response to Question 2 in the Commission's Supplemental Notice.

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3 NOAA. 2021. "Despite pandemic shutdowns, carbon dioxide and methane surged in 2020," NOAA Research News (April 7, 2021).

4 Cappucci, M. and J. Samenow. 2021. "Carbon dioxide spikes to critical record, halfway to doubling preindustrial levels," The Washington Post. (April 5, 2021).

5 Ritchie, H. and M. Roser. 2020. CO2 and Greenhouse Gas Emissions. Available at: https://ourworldindata.org/co2-and-other-greenhouse-gas-emissions.

6 NOAA. Earth System Research Laboratories Data. Available at: https://ourworldindata.org/co2-and-other-greenhouse-gas-emissions.

Figure 2

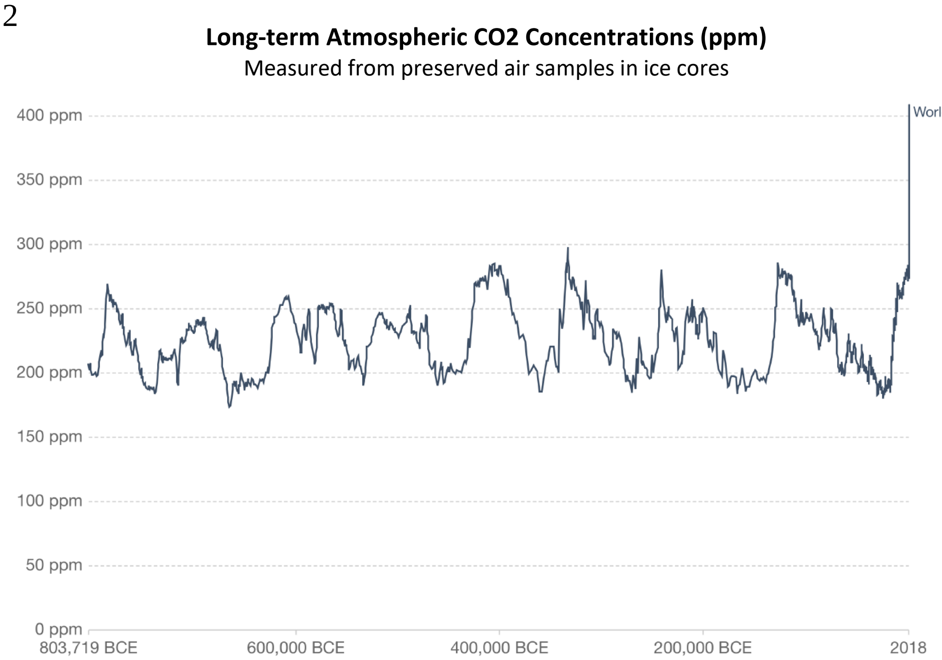
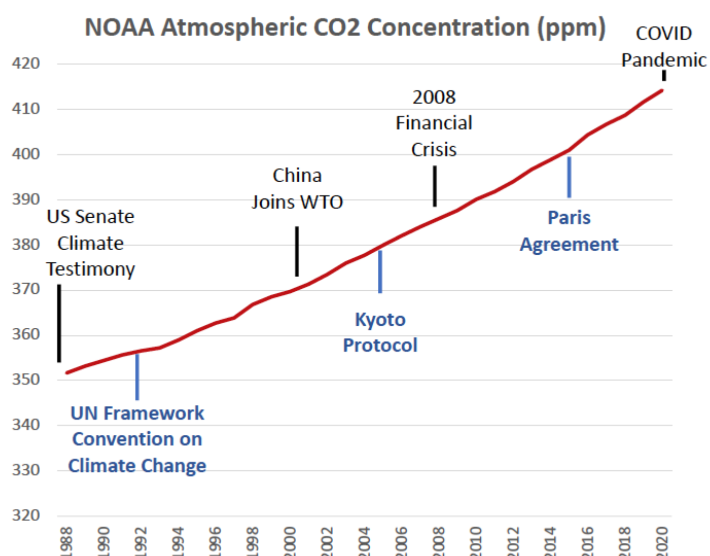


Figure 3

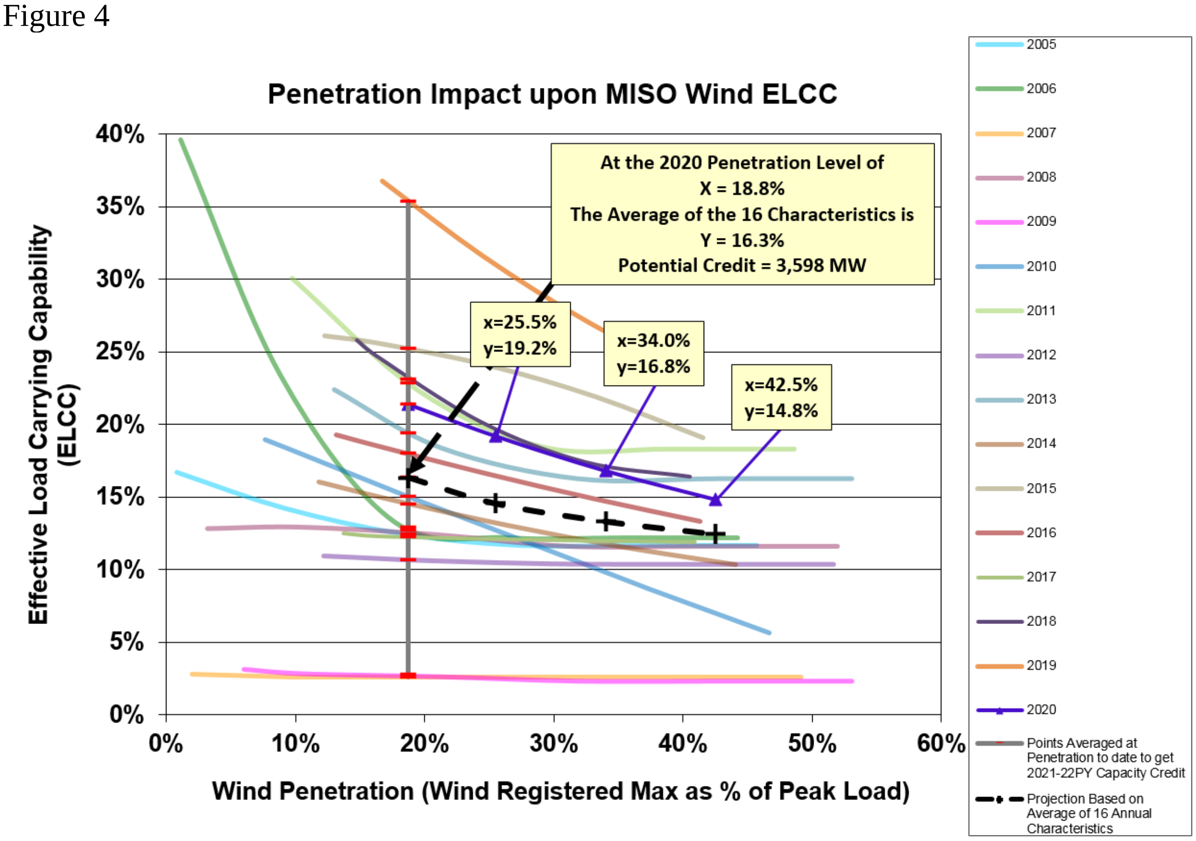


Current resource adequacy metrics and planning practices were not designed for extreme weather events and common mode failures. Conventional metrics, such as Loss of Load Expectation (LOLE), even the setting of the reserve margin, assume that resource outages and derates are independent of one another and uncorrelated. This assumption is no longer valid for either conventional or variable resources. Common mode events involving a combination of extreme weather, gas supply interruptions, coincident reductions in the output of wind or solar resources, cyber-attacks, and transmission failures will lead to simultaneous reductions in the output of multiple resources sometimes in tandem with unanticipated spikes in electric demand.

In the 1940's, the planning reserve margin metric was developed as a proxy for a probabilistic reliability metric measuring the ability of the power system to meet expected demand: a one-day-in ten years ("one–in–ten") Loss of Load Expectation (LOLE). Effective Load Carrying Capability (ELCC) was developed around 1960 as a way to assign a MW capacity value to generating units for the purpose of calculating LOLE. ELCC provides a value of "unforced" or "perfect" capacity that would provide an equivalent contribution to maintaining a target LOLE. Some ISOs, RTOs, and utilities have extended the calculation of ELCC to estimate the MW contribution of variable resources to meeting LOLE targets. Whereas the ELCC of a conventional unit is a well-defined value, the ELCC for a variable renewable facility or a fleet of variable renewable facilities is a function of not only the technology and the target LOLE but also the weather in any given year.

Figure 4 shows the range of ELCC values calculated by MISO for the wind fleet for the planning year 2021-2022.[7] The figure shows the ELCC at an 18.8% penetration based on conditions for each year from 2006 to 2020. Note that the range of values is from approximately 3% to 35%. The factors that varied from year-to-year are the wind fleet itself and the weather conditions. An analysis of the ELCC versus wind penetration shows at best a weak correlation between wind penetration and ELCC. The primary driver of differences across the 16 samples is weather patterns. Thus, each of the 16 values depicted by the intersection of the vertical line at 18.8% and the curves is a potential ELCC outcome for 2020-2021.

Figure 4



In addition, using LOLE as a metric does not address the nature of an event or costs to customers when insufficient resources are available. Neither LOLE nor ELCC helps planners identify the extreme events that planning will need to consider. Furthermore, LOLE fails to reflect locational

7 Planning Year 2021-2022 Wind & Solar Capacity Credit. January 2021. https://cdn.misoenergy.org/2021%20Wind%20&%20Solar%20Capacity%20Credit%20Report503411.pdf

reliability limitations, making it difficult to evaluate the tradeoffs between generation and transmission investments in maintaining system adequacy.

Current resource adequacy metrics and capacity mechanisms are not closely tied to the policy objectives of economic efficiency, customer choice, or reducing customer and societal costs. Resource adequacy targets, such as a one in ten-year LOLE, are based on engineering heuristics and have not been consistently supported by economic analyses of customer and societal costs. Simple pass/fail targets do not distinguish the costs of limited outages from those of widespread long-duration service interruptions. Despite the deployment of advanced meters to more than 70% of U.S. households[8] and development of smart technologies, we continue to rely on administrative capacity mechanisms to set capacity requirements and provide only limited recognition of potentially responsive demand. Additional discussion of resource adequacy metrics can be found in our responses to Supplemental Notice Question 7 and other questions below.

Power generation is in the midst of a significant transformation, which started more than a decade ago with the availability of inexpensive natural gas and improved turbine technology and has been followed by an increase in wind and solar capacity. In 2000, 52% of electricity generation (MWh) came from coal-fired power plants; gas, wind and solar represented 16% of generation. In 2020, gas-fired power plants produced 40% of the nation's electricity, wind and solar produced 12%, and coal's share of the generation mix had fallen to 19%.[9] The share of wind and solar in the resource mix will continue to increase. In 2019, solar, wind, and battery storage projects accounted for over 85% of the projects that had requested full interconnection studies in ISO, RTO, and utility interconnection queues.[10]

The shift to development of wind and solar resources has been driven in large part by a 90% reduction in the unsubsidized levelized cost of utility-scale PV and a 70% drop in the unsubsidized cost of wind from 2009 to 2020. Wind and solar have become cost competitive with fossil fuel generation and, where available, produce energy at a lower cost than gas or coal fired generators.[11] As renewable energy costs continue to decline and government and investors seek to mitigate climate risks, the market share of wind and solar will increase. Twenty-two states, plus the District of Columbia and Puerto Rico, have either pledged to achieve net-zero carbon emissions or set targets to rely on 100% clean or renewable energy by 2050.[12] At least 34 electric utilities, including ten of the twelve largest by market capitalization, have committed to become carbon

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8 Cooper, A. and M. Shuster. 2019. Electric Company Smart Meter Deployments: Foundation for a Smart Grid (2019 Update). Washington, D.C.: The Edison Foundation Institute for Electric Innovation.

9 U. S. EIA. 2021. Net Generation by Energy Source, Data from Form EIA-423.

10 Lawrence Berkeley National Laboratory. 2021. Generation, Storage, and Hybrid Capacity Interconnection Queues. Available at: https://emp.lbl.gov/generation-storage-and-hybrid-capacity.

11 Lazard. 2020. Lazard's Levelized Cost of Energy Analysis, Version 14.0.

12 The states include California, District of Columbia, Hawaii, Maine, Minnesota, Nevada, New Mexico, New York, Puerto Rico, Vermont, Virginia, and Washington, which have done so by statute, and Arizona, Colorado, Connecticut, Illinois, Louisiana, Maryland, Massachusetts, Michigan, Montana, New Jersey, Rhode Island, and Wisconsin by executive action. See: See: https://www.c2es.org/content/state-climate-policy/.

neutral by 2050.[13] As of the end of 2020, more than 1,500 business had pledged to reach a net-zero emission target.[14]

The Commission should account for expected changes in the generation mix in designing policies to maintain reliable electric service. A significant increase in wind and solar energy output is a likely and reasonable approach to mitigating climate risks. The Commission should facilitate reasonable investment in and, in the absence of an effective national mitigation policy, eliminate barriers to State support of clean and renewable energy. The Commission should not require individual resources to meet continuous performance requirements but should ensure that the electric system as a whole can provide reliable service. At the same time, each resource should be fairly compensated for its contribution to system reliability. This will require specific consideration of technologies and market designs that can balance the variability of low carbon renewable resources, including:

- Flexible price-responsive demand that can shape, shift, and modulate the timing of energy usage to manage ramps and help match short-term changes in the output of variable renewable resources. This will require changes to remove existing barriers and enable flexible demand to participate in wholesale power markets on a continuous basis that is not limited to dispatchable demand reductions from administratively determined baselines.

- Weather-independent balancing resources that can provide power during periods of low renewable resource output. Such resources would extend the system's balancing capacity beyond what can be cost-effectively provided by flexible demand and battery storage. Such resources would have to be able to come online quickly and may operate for a limited number of hours per year. To be certified as weather-independent, they will need the capability to operate in extreme weather. Over time, emerging low carbon technologies may provide a major portion of weather-independent balancing services.

- Expanded transmission, including new transmission lines to connect renewable resources to load centers, support efficient transactions, and diversify risk, and advanced transmission technologies that can enable transmission system optimization and provide flexibility for managing resource and network outages. As extreme events affect increasingly larger geographic areas, system operators may need to obtain power from more distant resources.

- Power markets that economically value contribution of resources to system reliability.

We will discuss the role of these technologies in our recommendations and responses to questions, including Supplemental Notice questions 1, 4, and 12, below.

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13 Electric companies include: AEP, Ameren, APS, Austin Energy, Avangrid, Avista, CMS Energy, ConEd, Dominion Energy, DTE Energy, Duke Energy, Edison International, Entergy, Eversource Energy, First Energy, Green Mountain Power, Hawaii Electric, Idaho Power, Los Angeles Department of Water & Power, Madison Gas & Electric, Mid-American, National Grid, New York Power Authority, NRG, Pinnacle West, Platte River Power Authority, PNM Resources, PSE&G, Puget Sound Energy, Sacramento Municipal Utility District, Sempra Energy, Southern Company, WEC Energy Group, and Xcel Energy. Whieldon, E. and J. Ryser. 2020. "Path to Net Zero: Cracks appearing in natural gas' role as bridge fuel," S&P Global Market Intelligence. (July 28, 2020).

14 Murray, J. and T. Gockelen-Kozlowski. 2020. "Global net-zero commitments double in less than a year," GreenBiz (September 23, 2020). Available at: https://www.greenbiz.com/article/global-net-zero-commitments-double-less-year.

Electric system reliability cannot by maintained through improvements in the bulk power system alone. Later in our comments and in our response to Supplemental Notice Question 17, we will discuss the need for community-based resilience planning and cooperation between Federal and State regulatory authorities.

II. Recommendations

Regulators are facing a more uncertain and complex future. We would encourage the Commission to consider the following actions, which reflect both recommendations in our EPRI report and work in additional areas of our practice:

- **Direct ISOs/RTOs to undertake a Regional Resilience-based Scenario Planning Process that Incorporates High Impact Common Mode Events**

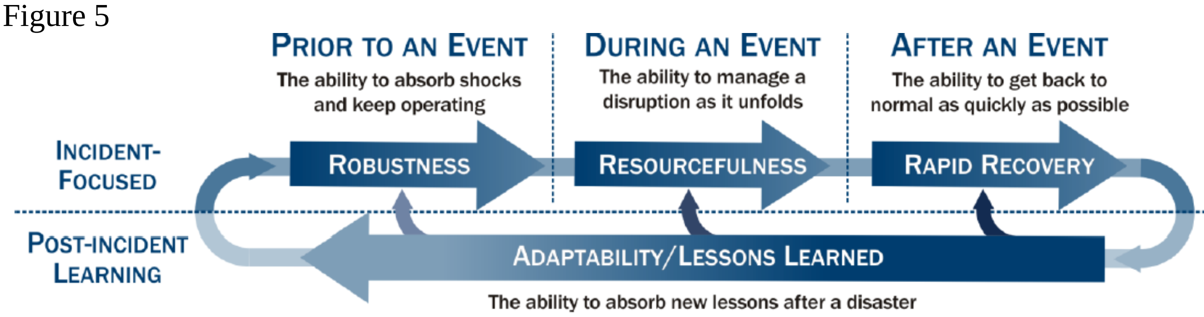
Each ISO/RTO should identify and characterize a set of high impact extreme weather events and other emerging risks (see response to Question 1 below) that could have a significant impact on service reliability in its region. An event may be high impact because its economic and societal costs would be very substantial, even if its probability of occurrence is relatively low. An event that would have moderately high costs and a higher probability of occurrence also may be a high impact event. High impact events will be different for different ISOs/RTOs. Identifying and describing relevant scenarios involving extreme weather and other common mode events is the first step in enhancing resilience-based planning and metrics.

While resilience might be enhanced in some cases by hardening or adding specific assets, effective resilience-based planning requires a broader and more flexible perspective that incorporates capabilities of resourcefulness and adaptability. Resilience-based planning recognizes that high impact events can occur and then evaluates how the system could absorb the impact while maintaining essential operations, manage the resulting disruptions as they occur, recover rapidly, and evaluate and apply lessons learned. Figure 4 provides a high-level overview of a resilience-based framework.[15]

Although the industry has a long history of risk-based planning, risks related to extreme weather events, significant reliance on variable resources, greater sectoral interdependence, and evolving cyber-security threats in many cases were not the risks that planners had in mind when designing existing power systems. System plans were often based on N-1 or, in some cases, N-2 contingencies, meaning that the system could continue to operate given the failure of one or two key components. Such planning did not focus on common mode events involving the coincident failure of multiple generating units and/or other critical systems.

15 National Infrastructure Advisory Council. 2010. A Framework for Establishing Critical Infrastructure Resilience Goals: Final Report and Recommendations.

Figure 5



Conventional planning typically was conducted within a utility, ISO, or RTO, often with limited initial outside input. Planning for emerging risks may require coordination across sector boundaries, including with state and local authorities, fuel supply and telecommunications providers, and communities that can help planners evaluate which facilities have the most critical service continuity requirements, taking into consideration local social and economic justice concerns.

Historically, outages typically occurred in areas of a distribution utility that could be isolated and brought back into service with the mutual assistance of service restoration teams. However, the areas impacted by extreme weather events are becoming far larger, in some events affecting entire regional markets or multi-state regions. The extensive outages in February 2021, for example, impacted virtually all of ERCOT, MISO South, and significant portions of SPP. There reportedly was not enough power available to import from neighboring markets for ERCOT fully use its limited tie lines to other interconnections. Given the increasing scale of extreme weather events, it is appropriate that a planning process for high impact events be developed at regional level.

To enhance scenario planning, FERC also should request that NOAA develop, with industry and public input, a classification system for extreme weather events that impact power systems. Perhaps this could be an extension of NOAA's Climate Extremes Index (CEI).[16] Such a system could provide a standard planning reference; enable analyses of trends and the compounding impact of increases in the frequency, intensity, duration, and spatial coverage of weather events[17]; enable correlation between extreme weather attribute types including duration and spatial coverage with power system outcomes; and support the development of performance baselines for program evaluation. A classification system would include event- and region-specific thresholds, comparable to the regional thresholds in NOAA's Regional Snowfall Index.

As ISOs/RTOs develop and report back to the Commission on their enhanced planning processes, the Commission can utilize their experience to evaluate how NERC planning standards may need to be revised to address the risk of common mode failures.

16 Gleason, K.L., J.H. Lawrimore, D.H. Levinson, T.R. Karl, and D.J. Karoly 2008: A Revised U.S. Climate Extremes Index. J. Climate, 21, 2124-2137

17 Zscheischler, J., Martius, O., Westra, S. et al. A typology of compound weather and climate events. Nat Rev Earth Environ 1, 333–347 (2020). https://doi.org/10.1038/s43017-020-0060-z

- **Direct ISOs/RTOs to perform regional Value of Lost Load (VOLL) studies that include assessments of how customer and societal outage costs may change during widespread and long-duration outages.**

None of the widely used reliability metrics – Planning Reserve Margins, LOLE, Loss of Load Probability, Expected Unserved Energy, Energy Not Supplied, Curtailment indices, or common distribution reliability metrics (SAIFI, SAIDI, CAIDI) – include in their calculation an explicit economic component.

It is essential to consider the high costs of extreme weather and common mode events and to distinguish those impacts from those of limited short-term service interruptions. Doing so will require better estimates of customer and societal costs. Most studies of customer outage costs cover only short duration service interruptions. Some frequently referenced studies are now more than twenty years old and include data from only a subset of regional markets.

ISOs/RTOs are in a position to coordinate the development of regional VOLL or customer outage cost studies and to develop best practices that can then be applied outside the organized markets.

- **Direct ISOs/RTOs to develop Value of Load at Risk reliability metrics**

Current reliability metrics at most identify an expected quantity of unserved energy but say nothing about the economic costs and societal consequences of experiencing major service interruptions. Extreme weather and other common mode events have increased the probability and economic consequences of high impact events. However, none of the industry's standard reliability metrics reflect the costs of such events.

In the two prior recommendations, we encouraged FERC to direct ISOs/RTOs to develop enhanced scenario planning for high impact events and to improve the valuation of customer outage costs. Building on these steps, FERC should direct ISOs/RTOs to use a probabilistic methodology to develop reliability metrics that incorporate economic costs and reflect the expected frequency, duration, depth, and consequences of different outage scenarios.
Value of Load at Risk would be analogous to the Value at Risk metric in finance. It would provide an expected dollar valuation of unserved energy under a given portfolio of resources and responsive demand.

- **Direct ISOs/RTOs to further develop efficient, market-based, probabilistic approaches that consistently value the contributions of variable and weather-independent resources, transmission, and flexible demand**

Common mode events and variable resources broaden the range and distribution of potential reliability events. Reliability is a probabilistic concept which can only be suitably addressed with an evaluation of the entire range of potential outcomes and their probabilities, including the outcome and probabilities of common mode events. Additional data also may be required for such analysis.

Although ISOs/RTOs use certain probabilistic models, the models, methodologies, and uses of probabilistic analysis may differ among system operators. Additionally, it is not clear the extent to which ISOs/RTOs may be considering extreme weather or other common mode events in their applications of probabilistic models. FERC should organize a task force to identify the data requirements and the processes by which the required data can be made available for analysis.

Probabilistic optimization models can be used to identify plans that perform well when taking high impact events into consideration and include efficient levels of weather-independent balancing resources and flexible demand.

TCR is currently developing, with MISO participation and ARPA-E support, a probabilistic modeling platform for Stochastic Nodal Adequacy Pricing (SNAP). SNAP will enable ISOs/RTOs to continuously reflect the risk of supply disruptions in a Marginal Reliability component of nodal hourly prices for resource supply, transmission, and demand. SNAP could augment or replace an Operating Reserve Demand Curve-type structure with a time- and location-specific probabilistic representation of risk. It also could provide regulators an opportunity to observe how consumers value reliability based on their market participation. SNAP is an efficient, market-based approach for consistently determining the reliability value of and compensation for resources – including weather-independent balancing resources, transmission, and changes in demand – including the intelligent management of flexible price-responsive demand. The key attributes of SNAP are that it would be:

- Nodal and Hourly: Time- and Location-specific Marginal Reliability values would be included in nodal and hourly market prices.

- Transparent: SNAP supports the development of a resilient and efficient portfolio of resources. It provides an incentive for resources to have the capability to operate in extreme conditions, without requiring continuous performance of each resource.

- Probabilistic: Built on granular probabilistic weather forecasts, SNAP would provide fair compensation for weather-independent resources in all the hours in which there are scarcity risks, instead of only implementing very high prices when scarcity conditions actually occur. This reduces uncertainty for investors

- Market-based: SNAP Enables Demand Participation. Instead of relying on an administratively determined demand curve, SNAP allows retailers and consumers with flexible demand to submit hourly demand curves reflecting how demand would respond to changing prices.

SNAP provides an opportunity to develop markets that are reliable, efficient, and support the necessary balance of variable renewable resources, weather-independent balancing resources, and flexible demand.

- **Develop a real-time, coordinated market for electricity and natural gas, including data to assess the reliability of gas fuel supplies**

Beginning with a technical conference initiated by a notice of inquiry, FERC should lead the conversation on how to better coordinate the electricity and natural gas markets. The data needed to evaluate the reliability of gas supplies under stressed conditions are not available. Pipelines generally have been unwilling to disclose the data needed to model their operations even under confidentiality agreements comparable to those used to protect Critical Electric Infrastructure Information. Moreover, the data that would be needed to understand why gas supply shortages have occurred are inadequate. U.S. Department of Transportation incident reports have provided the most comprehensive public source for data on pipeline outages, capacity constraints, curtailments, and operations. However, such reports could explain less than twenty percent of the generation lost due to gas supply interruptions in the period from 2012 to 2017.[18]

Unlike the Electric Reliability Organizations that operate under FERC supervision, there are no comparable gas reliability organizations to gather data, analyze and share lessons learned, or develop standards.

Even after FERC Order 809, there is still only limited coordination between gas and power system operations. For example, a gas-fired generating unit looking to operate the next electric market day, which begins at midnight, may need to submit an offer in the Day-Ahead market by 10:30 AM Eastern Time on the prior day. The unit would have lined up gas supply and delivery bilaterally, however, these preliminary arrangements typically would not be backed up by a delivery guarantee. After the Day-Ahead power market clears and becomes a financially binding operating schedule, the generator will have only a short time in which to make delivery nominations with the pipeline for the next gas day. The generator may need to specify fixed or ratable gas supply takes for multi-hour time periods. This process exposes the generator and the electric system operator, who may be relying on gas to balance variable renewable resources, to a wide range of risks. If the gas deliveries needed by the generator are not confirmed by the pipeline, the generator may face significant financial exposure. Even if the generator’s initial delivery schedule is confirmed, the unit may not be in position to respond in real time to changes in electric prices and market conditions, increasing the reliability risk for systems that rely on variable resources.

This is an issue that could be addressed through near real-time coordination between gas and electric system operations. Doing so could also increase gas availability during tight market conditions. TCR principals, working with Los Alamos National Laboratory, developed a Gas-Electric Co-Optimization modeling platform (GECO). GECO combines detailed power system and transient pipeline optimization models. Given a sample of pipeline data, we were able first to calibrate the models to actual pipeline operations. When systems were optimized, the modeling identified a potential to increase gas supplies by 7% to 9% during the highest priced hours of the 2014 Polar Vortex event.[19] This underutilization of the gas system is comparable to what was observed in electricity prior to the development of organized real-time markets.

These are complex cross-sectoral issues. However, unless these concerns are resolved it is difficult to see how the power system, particularly with increasing reliance on variable renewable resources, will be able to rely on natural gas as a reliable weather-independent fuel supply.

- **Remove barriers to and facilitate the participation of Flexible Demand in Wholesale Power Markets**

To maintain reliability, power systems that depend on a high level of variable renewable resources will need to also rely on intelligent systems such as those that manage the thermal inertia in buildings and refrigeration as well as the timing of flexible electric vehicle, agricultural, and

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18 Freeman, G., J. Apt, J. Moura, “What Causes Natural Gas Fuel Shortages at U.S. Power Plants?” Energy Policy, Vol. 147, December 2020.

19 Rudkevich, A., A. Zlotnik, J. Goldis, P. Ruiz, X. Li, A. Beylin, R. Philbrick, R. Tabors, and S. Backhaus. 2018. Transient Simulation and Optimization of Natural Gas Pipeline Operation and Applications to Gas-Electric Coordination. FERC Tech Conference (6/27/2018)

industrial demand. Flexible demand can be shaped, shifted and modulated to balance intraday variability and ramps in wind or solar output.

The potential contribution of cost-effective flexible demand is large. It has been estimated that, in addition to expanding existing demand response programs, U.S. power systems will add more than 120 GW of cost-effective flexible demand by 2030.[20] Heating, cooling, ventilation, and refrigeration – end uses where the management of thermal inertia could provide timing flexibility – account for 37% of all U.S. electricity consumption.[21] A smart thermostat, for example, can shift demand by pre-cooling, reducing peak residential air conditioning demand, in some cases by as much as 35% to 50%.[22] The timing of flexible demand often can be modified over time periods of as much as a few hours with little apparent impact on the energy services that customers enjoy. For example, one study of residential demand response potential found that managing thermal inertia within narrow limits, 1°C for home heating and cooling, 2°C for residential refrigeration, and 3°C in residential water heaters, could shift a majority of residential demand in California.[23] When compared to battery storage, demand flexibility provides a relatively inexpensive way to manage short-term resource variability. The storage medium – thermal inertia, timing, or locational flexibility – already exists. In many instances, sensors, communications, and control systems are also present. As a result, flexible demand can provide significant reliability benefits in many cases at a lower cost than other forms of energy storage.[24]

Within the next few years, an individual utility could have millions of smart thermostats, EVs, intelligent building management systems, and other controllable loads within its service territory. Although it may not be practical to centrally dispatch millions of devices, customers with flexible demand could be enrolled in programs that continuously communicate incremental price incentives. Unfortunately, most existing ISO/RTO programs treat demand response as a resource and require participants to meet dispatch and performance requirements comparable to those applied to supply-side resources. This creates unnecessary barriers to participation.

To remove such barriers, a 2016 National Academies report on the deployment of clean electric technologies:

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20 Hledik, R., A. Faruqui, T. Lee, and J. Higham. 2019. The National Potential for Load Flexibility: Value and Market Potential through 2030. New York, NY: The Brattle Group.

21 U.S. Energy Information Administration. 2020. Electric Power Annual 2018. Washington, D.C.: U.S. Department of Energy; Schwartz, L. M. Wei, W. Morrow, J. Deason, S. Schiller, G. Leventis, S. Smith, W. Leow, T. Levin, S. Plotkin, Y. Zhou, and J. Teng. 2017. Electricity end uses, energy efficiency, and distributed energy resources baseline: Industrial Sector Chapter. LBNL-1006983. Berkeley, CA: Lawrence Berkeley National Laboratory.

22 Robinson , J., R. Narayanamurthy, B. Clarin, C. Lee and P. Bansal. 2016. "National Study of Potential of Smart thermostats for Energy Efficiency and Demand Response," Proceedings of the 2016 ACEEE Summer Study on Energy Efficiency in Buildings. Washington, D.C.: American Council for an Energy Efficient Economy; Harding, M. and C. Lamarche. 2016. "Empowering Consumers Through Data and Smart Technology: Experimental Evidence on the Consequences of Time-of-Use Electricity Pricing Policies," Journal of Policy Analysis and Management. Vo. 35, No. 4; Herter, K. and Y. Okuneva. 2014. SMUD's Smart Thermostat Pilot – Load Impact Evaluation. Sacramento, CA: Sacramento Municipal Utility District; and Nevada Power Company. 2013. Application of Nevada Power Company d/b/a NV Energy for Approval of its 2014 Annual Demand Side Management Update Report as it relates to the Action Plan of its 2013-2032 Triennial Integrated Resource Plan, Volume 5 – Technical Appendix.

23 Mathieu, J. 2012, Modeling, Analysis, and Control of Demand Response Resources, Lawrence Berkeley National Laboratory, LBNL-5544E.

24 MIT Energy Initiative. 2016. Utility of the Future: An MIT Energy Initiative response to an industry in transition.

- Recommended that electric system operators "consider utilizing their capability to build response curves that reflect predictable price-demand relationships to enable flexible demand that responds to short-term prices and incorporate those curves into the forecasts they use for operations and planning purposes."

- Recognized that in some cases wholesale settlements are "based on utility load shapes not on the actual load patterns of each retail supplier's customers." When this occurs neither the customer nor the retail supplier has any incentive to manage when electricity is used.[25]

- Found that, "The settlement of load in wholesale markets on a 5- or 15-minute interval basis instead of hourly would enable and provide an incentive for a much greater role for automated demand in maintaining reliability, balancing variable resources, and reducing peak demand."

- Noted that "look ahead" price forecasts, such as those published by New York ISO and ERCOT, "could be used to position demand for anticipated system conditions and would be highly beneficial if made available to devices all the time, everywhere they are available, in a standard format, as inexpensively as possible. The Federal Power Act directs FERC to 'facilitate price transparency' and to 'provide for the dissemination on a timely basis of information about [wholesale] prices … to … the public.' FERC is authorized, if necessary, to 'establish an electronic information system for this purpose.'"[26]

FERC should consider the Academies' findings and recommendations and initiate an inquiry on how to better integrate flexible demand capabilities into wholesale power markets.

In addition to completing the development of the demand side of wholesale markets and encouraging the development of ISO/RTO programs that will engage flexible demand and enable flexible demand to continuously respond to anticipated changes in wholesale market prices, the Commission should encourage retail regulatory authorities and utilities to develop rate designs that include a dynamic component reflecting changes in wholesale prices.

25 Wholesale settlements are FERC jurisdictional. In systems with retail competition where customers of multiple suppliers are located on the same circuit, FERC could require wholesale settlements to be based on interval or hourly Advanced Metering Infrastructure (AMI) data where available. In the absence of AMI data, FERC could require wholesale settlements to be based on sensor measurements for a statistical sample of each wholesale customer's actual demands.

26 National Academies of Sciences, Engineering, and Medicine. 2016. The Power of Change: Innovation for Development and Deployment of Increasingly Clean Electric Power Technologies. Washington, D.C: The National Academies Press. See also: Centolella, P. and A. Ott. 2009. Integration of Price Responsive Demand into PJM Wholesale Power Markets and System Operations.

III. Additional Considerations: Reducing Barriers to Innovation

An electric system that relies on variable renewable resources to achieve significant reductions in carbon emissions while supporting the electrification of additional end uses will need reliable, low carbon, weather-independent balancing resources. Today variable renewable resources are being balanced in large part by gas fired generators, which are neither reliable weather-independent resources under stressed conditions nor carbon neutral.

There are classes of emerging technology that could produce competitive, reliable, carbon-neutral, weather-independent resources, including: advanced gas technologies with carbon capture and sequestration and improved gas supply reliability, renewable energy to hydrogen or other fuels, long-duration energy storage, advanced or hot rock geothermal, advanced nuclear and fusion technologies. The commercialization of these technologies will require overcoming barriers that have historically limited and delayed energy innovation. This includes what is often regarded as a commercialization "valley of death" for technologies seeking to move from demonstrations into the early adoption stage.[27]

FERC can convene technical conferences highlighting promising weather-independent resource technologies and may have a role in the innovation ecosystem needed to accelerate the commercialization of technologies that will be critical to the future reliability of the electric system. FERC should consider what may be an appropriate Commission role in Federal energy innovation policy.

27 Ibid.

IV. Responses to Questions in the Supplemental Notice of Technical Conference Inviting Comments

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?*

The most critical challenge for electric system reliability brought on by climate change and extreme weather events is to change the paradigms and analytic tools which have allowed operators to keep the lights on for the past 100 plus years, but which are no longer sufficient in a decarbonizing energy system that must be resilient to the impacts of extreme events. The more specific challenges are, to a large extent, independent of the time frame.

- Climate change is marching inexorably forward and will continue to do so for the remaining lifetimes of all decision makers in the power industry. Remaining focused on only short-run costs could have significant costs. Operational changes must be field-tested and investments must be made in the short-run to mitigate the medium- and long-run economic and social consequences.

- Extreme events can no longer be evaluated as low frequency, implying that they are so infrequent that they cannot be planned for. Reliability can no longer be evaluated based on the assumption that failures are singular independent occurrences, ignoring the potential for common mode failures. Heat waves, wildfires, drought, tropical storms, extreme precipitation, high winds, reductions in wind and solar energy, and cyber/physical attacks that may seek to take advantage of a system weakened by other factors may contribute to common mode events involving the failure of multiple generating units and spikes in demand. Such events can affect multi-state regions with large and diverse populations and have multi-billion dollar economic impacts. The challenge is how to incorporate these events into operations and planning.

- Simultaneously adapting to the impacts of extreme weather, transitioning to low carbon resources including significant variable renewable resources, and accommodating the increasing electrification of transportation, industry, and other end uses requires an evolution from the deterministic view to a stochastic approach to daily operations and to medium-term and the long-term planning and resource adequacy metrics. Scenario-based planning for foreseeable extreme events is needed take on an entirely new dimension in time and complexity.

- The current operational and planning tools and even the needed data to operate those tools are insufficient to the forward-looking, time-based needs of the industry.

    - Today, the electric industry relies on gas fired generation, which is neither carbon neutral nor currently reliable in stressed conditions, to balance variable renewable resources. For natural gas to become a reliable weather-independent balancing resources the data is needed to evaluate gas industry performance and enable near real-time coordination of gas and electric operations and markets.

    - Demand for electricity is increasing with decarbonization while our industry and regulatory structures appear averse to creating the economic incentives to nudge demand downwards in a balancing situation. Flexible demand is needed to enhance reliability and balance high penetrations of variable renewable resources.

Distributed intelligent devices and systems can shape, shift, and modulate a significant portion of electric demand in response to anticipated prices. However, this will require changes in the demand side of wholesale markets, implementing wholesale market programs and pricing designed to elicit continuous responses from flexible demand, and eliminating barriers to demand participation.

    - Variable and weather-independent resources, transmission, and changes in demand based in part on their stochastic time- and location-specific contribution to marginal system reliability will require fair and reasonable compensation.

- Then there are the physical challenges that can only be dealt with in the medium- to long-term that include:

    - Hardening of the power system to cyber-attacks.

    - Weatherizing the power and gas system assets to survive extreme heat and cold to prevent the impacts such as were seen in February 2021 in Texas.

    - Sectionalizing the bulk power system and distribution grid so that blocks of the grid (and certainly critical facilities) can be carved off from the main system and continue to operate during extreme events.

    - Developing an even more extensive, integrated and, critically, flexible transmission grid that can move interregional renewable energy to demand as solar or wind generation fluctuates across the country or as extreme events take out generation or transmission assets.

- Achieving a reliable low carbon electric system will require technological innovation including the development of carbon neutral weather-independent balancing resources.

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 designed, built, sited, and operated?*
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?*

Response to Questions 2 and 3:

The last decade has seen heat wave frequency, duration, as well as the length of the heatwave season increase by roughly a third over the prior decade. Looking forward, researchers estimate that impacts of heat wave events – the intensity, duration, increase in cooling degree days, area covered, and population impacted – will likely double within the next thirty years – a 2.5% average annual increase in the impacts of extremely hot weather. A prudent forward-looking projection should assume for most major metropolitan areas that the intensity, area coverage, length of the average heat wave event, and length of heat wave seasons will grow at least 25% in the coming decade.

Higher temperatures, earlier snowmelt, and later onset of the fall rainy season will combine with existing drought conditions to increase the intensity, duration, and impact from wildfires. Experts fear that 2021 is likely to exceed the record 10.127 million acres burned in 2020 due to the higher levels and broader expanse of current drought conditions in the West compared to spring 2020. In the past five years (2016-2020), the acreage burned in wildfires was 20% higher than in the 2011-2015 timeframe, and 117% higher than average acres burned in the 1990's. A prudent forward-looking projection should assume greater intensity, area coverage (+25%), and extended length of the wildfire season in the coming decade (wildfire seasons are evolving to be "year-round"). It should also be noted that California wildfires in 2020 had significant impact both on availability of power (power cut off to avoid fires), and shortage of solar output due to smoke.[28]

Cold snaps such as those seen in the 2014 Polar vortex and the 2021 Texas freeze have become a feature of winter weather in the Eastern and Central US. Some of the empirical research has identified a correlation between these anomalous cold events and the impact of warmer Arctic temperatures on a band strong high-altitude winds known as the polar jet stream. The Arctic has warmed more than twice as fast as the global average, losing much of its reflective sea ice. It is thought that warmer Arctic temperatures may be slowing or blocking the polar jet stream forcing colder air south and impacting weather in the U.S.[29] There is considerable debate within the meteorological research community regarding whether these polar vortex events will occur more frequently in the future.[30] In any event, unseasonable widespread cold snaps like we saw in Texas should be considered in future planning.

There has been a consistent six-decade long trend toward greater rainfall occurring during extreme precipitation events throughout most of the continental U.S. with the exception of the comparatively dry climates in Southwestern states.[31] Warmer air holds more water vapor, leading to more intense storms given the right conditions.

Hurricanes and tropical storms are also maintaining their intensity and producing more rain over larger areas after reaching land. A leading study has found that, "[I]n the late 1960s a typical hurricane lost about 75 percent of its intensity in the first day past landfall, now the corresponding decay is only about 50 percent. …Even when the intensity at landfall remains the same, the slower decay means that regions far inland face increasingly intense winds (accompanied by heavy rainfall). Consequently, the economic toll incurred keeps soaring."[32] While the trend in frequency of landfall tropical storms is inconclusive, lengthening duration of storm intensity suggests that a

28 California ISO, California Public Utilities Commission, and California Energy Commission. 2021. Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave. (January 13, 2021).

29 Francis Jennifer and Skific Natasa. 2015. Evidence linking rapid Arctic warming to mid-latitude weather patterns. Phil.Trans. R. Soc. A.3732014017020140170. http://doi.org/10.1098/rsta.2014.0170

30 Cohen, J., J. Francis, R. Kwok, and J. Overland. 2019. "Divergent consensus on Arctic amplification influence on midlatitude severe winter weather," Nature Climate Change (December 2919).

31 Easterling, D.R., K.E. Kunkel, J.R. Arnold, T. Knutson, A.N. LeGrande, L.R. Leung, R.S. Vose, D.E. Waliser, and M.F. Wehner, 2017: Precipitation change in the United States. In: Climate Science Special Report: Fourth National Climate Assessment, Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 207-230, doi: 10.7930/J0H993CC.

32 Li & Chakraborty. 2020. "Slower decay of landfalling hurricanes in a warming world," Nature, Vol. 587.

prudent approach would assume that landfall tropical events will bring more rain on average, and extend further inland, than the storms we have experienced to date.

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?*

Response:

The report *Exploring the Impacts of Extreme Events, Natural Gas Fuel and other Contingencies on Resource Adequacy.* Prepared by Centolella, Gildersleeve, Rudkevich, Shavel, and Tabors, (EPRI, January 2021) by the authors of these comments focuses precisely on this issue of system reliability given the increased prevalence of common mode failures.

Critically, while in the past geographic diversity allowed for resource sharing, the expanded geographic footprint of many of these extreme weather events today makes it challenging for neighboring regions and states to mitigate the risk. California was unable to import significant power from its neighbors during the heat events of the summer and fall of 2020 because their neighbors were suffering under the same heat wave.

Similarly, the Texas polar vortex event of February 2021 was part of a cold snap that extended across much of the south-central US, and northwards all the way to the upper Midwest, thus limiting how much excess power was available for export to Texas during the event (even presuming there was sufficient transmission capacity between regions). The gas demand from the upper Midwest also placed more stress on the natural gas system in Texas.

With the expansion of the geographic extent of extent and impact of extreme events, the availability of transmission transfer capability increases in importance. Transmission can no longer be seen as a means of transferring energy from a remote, large-scale generator to the urban load. In today's world transmission needs to evolve to be the common carrier of renewable and weather-independent energy between regions. It needs to be the backbone for reliability as well as delivery of power in the evolving energy system. In today's power system, transmission's existing and future role in provision of reliability is both under-appreciated and under-valued.[33]

Advanced transmission technologies such as Dynamic Line Rating, Flow Control, and Topology Optimization, which expand the flexibility of the system allow for rapid reconfiguration of transmission and increase utilization of the existing assets must be seen as critical resources in improving reliability, increasing efficiency, and responding to extreme events.

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33 Van Horn, K, Pfeifenberger, J, Ruiz, P, The Value of Diversifying Uncertain Renewable Generation through the Transmission System, Boston University Institute for Sustainable Energy, September 2020.

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?*

Response:

FERC should require the following improvements to be implemented:

- Advanced natural gas pipeline system control based on transient modeling and optimization of system operations at a regional level. The control system should be based on modern real-time metering and state identification technologies, that provide visibility of locational pressure and flow conditions in real-time.

- Development of granular real-time pricing of natural gas, based on the development of an advanced information and control system and consistent with the physics of natural gas flows and with the engineering constraints of pipeline operation and control.

- Natural gas pricing that is consistent with physics of optimal pipeline operations. This would make it possible to radically improve gas-electric coordination. Pipelines should assess available capacity locationally and in real-time. They should be providing real-time access to that capacity on an economic basis through a transparent and equitable price discovery mechanism. Development of such economic mechanism would enable natural gas and electric networks to exchange economic signals facilitating the improvement of system reliability and reduction of overall system costs.

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?*

NO RESPONSE

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 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?*

Response:

In our review of recent extreme events, such as the February 2021 Texas freeze and the California heatwave in August 2020, the forecasted peak demand was based primarily on a review of the historical record. Based on the trends quantified in response #2, it feels prudent to forward-project weather trends to accommodate the likelihood that future weather will be more extreme than what has been experienced to date.

In addition, our review of the Texas event shows that the "worst case" scenarios used by planners for contingency planning only assumed "pairs" of bad things to happen at once (e.g., extreme peak load and low wind; or extreme peak load and generation failures). No scenario was constructed that included demand spikes, generation failures, gas supply disruptions, and renewable resource shortfalls occurring simultaneously.

The Commission should consider a Technical Conference that focuses on the development and application of probabilistic, forward-looking, short term planning methods that explicitly incorporate the joint probability of common mode events that create extreme social outcomes and economic impacts on consumers.

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?*

Response:

Regional planning authorities should conduct, and relevant regulatory authorities and individual utilities should actively participate in, a regional resilience-based scenario planning process to address extreme weather events with input from fuel supply and telecommunications providers and affected communities. Measures to harden specific facilities may well contribute to the power system's ability to absorb the impacts of extreme weather. However, asset hardening is only one of the responses that should be considered in resilience-based planning. Such plans should also consider how to segment the distribution grid and maintain service to critical facilities, manage the disruptions that will occur during extreme weather events, recover rapidly, and evaluate and apply lessons learned. Decisions to harden specific assets should reflect relevant the risks that are relevant for the region as well as local circumstances and concerns.

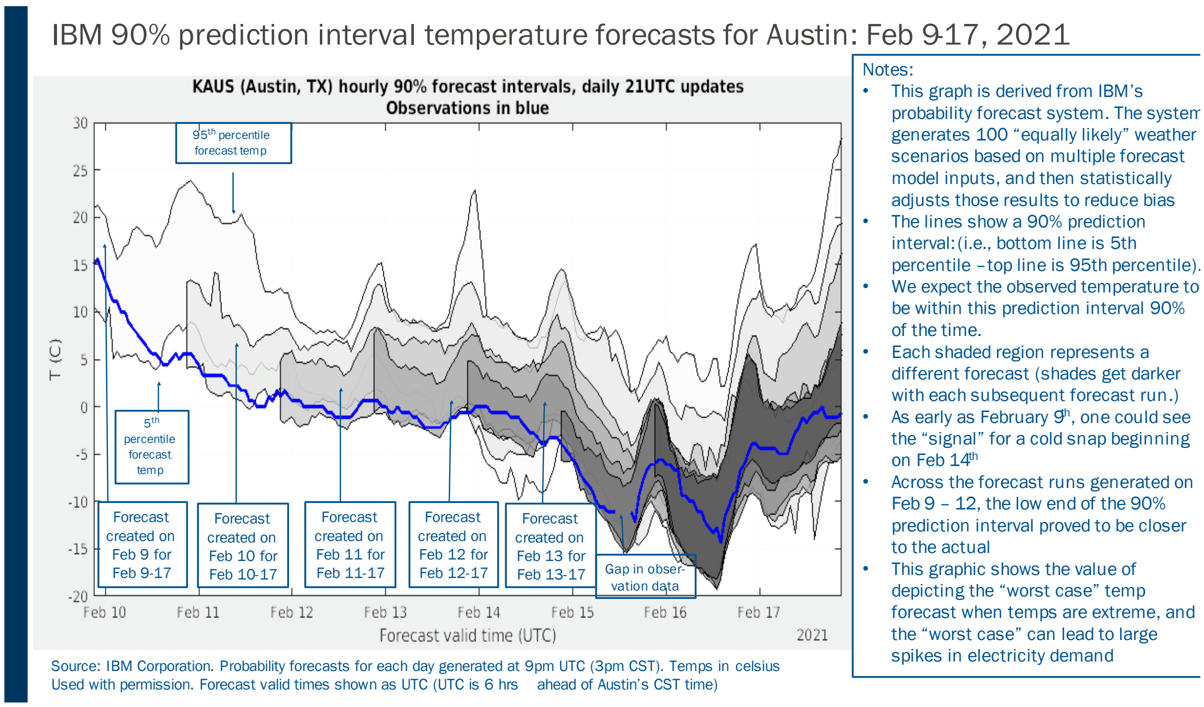
9. *How have entities responsible for real-time operations (e.g., utilities, RTOs/ISOs, generator operators) changed their operating practices in light of the challenges posed by climate change and extreme weather events and what potential future actions are they considering? What additional steps should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

Response:

As we extensively evaluate in *Exploring the Impacts of Extreme Events, Natural Gas Fuel and other Contingencies on Resource Adequacy.* Prepared by Centolella, Gildersleeve, Rudkevich, Shavel, and Tabors, (EPRI, January 2021), operating practices must move from a focus on the mean, the mode or point of central tendency to recognize decision value of understanding the probability distribution in forecasts. From the perspective of the operator there is a material difference in both likely issues and real time operational costs when the probability distribution of forecasted temperature has a limited range versus when the dispersion (as shown in the figure below) shows a wide distribution of potential outcomes. Specifically, real-time operators should consider the use of 1-10 day probabilistic weather forecasts in estimating the entire range of potential demand and supply outcomes for a given time frame. These probabilistic weather forecasts are available for the core weather parameters utilized in load and renewable supply forecasts.

The Texas event is a good example of the value of probabilistic weather forecasts for extreme events. As shown in the Figure 6, the upper and lower gray lines show the 5th and 95th percentile temperature forecasts for the timeframe in question. As can be seen, the actual temperatures (blue line) were fairly close to the 5th percentile forecasts created three to five days ahead of the event. Particularly when the forecasted temps are extreme to begin with for a particular region, these probabilistic forecasts show an outer bound on how "bad" things can get.

Figure 6



The Commission should consider a Technical Conference that focuses on the development and application of probabilistic, forward-looking, short term planning methods that explicitly incorporate the joint probability of common mode events that create extreme social and economic impacts on consumers. The Technical Conference should also recognize, as discussed above, the criticality of widespread impacts of events that are regional or multi-regional in nature. This was seen in February 2021 when the extreme cold even required interruption of consumer loads not only in ERCOT but in MISO and SPP as well.

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?

Response:

Seasonal resource assessments, when they are implemented as is the case at NYISO and ERCOT, provide additional opportunity for identification of conditions of potential inadequacy. These studies do not, however, adequately account for either common mode events or extreme events perceived to have a low probability. In ERCOT, for the winter of 2020/2021, the "Range of Potential Risks" included only 3 sensitivity cases. In specifying these cases, ERCOT planners failed to consider the possibility that extreme peak demand and extreme unit outages might coincide with low wind output. In addition, each of the input sensitivities was based on only a short history of each of the parameters and therefore these scenarios understated the conditions observed in February 2021. Additionally, ERCOT does not appear to have considered how severe weather could impact gas supplies.[34]

NERC publishes Summer and Winter Reliability Assessments for each upcoming season. The November 2020 2020-2021 Winter Reliability Assessment[35] stated the following about ERCOT for the upcoming winter: "ERCOT also expects to have sufficient resources under scenarios that assume low wind output as well as extreme peak load conditions with an associated increase in unit outages and derates due to weather-related natural gas supply disruptions." About MISO NERC noted: "MISO does not anticipate resource availability issues for the upcoming 2020–2021 winter season. Based on prior winter readiness and fuel deliverability surveys, appropriate measures have been taken, making readying units for potential severe winter weather, and fuel deliverability is robust." NERC however did note that "Potential extreme generation resource outages and peak loads that can accompany extreme winter weather may result in reliability risks in MISO, ERCOT, and WECC-NWPP & RMRG areas as well as the Canadian Maritime provinces."

These Seasonal Assessments could be extremely valuable if they looked at a much wider range of system conditions. The NERC Long Term Assessments are richer analyses that rely, at least to some extent, on probabilistic assessments. Nevertheless, NERC's main metric remains primarily the reserve margin, and NERC does not consider scenarios that correspond to extreme events. NERC Assessments that considered high impact low probability scenarios relevant for each region would be a very valuable improvement to the current reports. Interestingly, in the 2020 Long Term Assessment NERC identifies shoulder periods as a particular risk in ERCOT. Historically, it did make sense to look at the winter and summer periods. But with high penetrations of renewables and changing patterns of demand across the year, other periods are likely to emerge as high risk. Thus, it would make sense for NERC to extend its assessments to shoulder periods as well as winter and summer.

Independent of whether resource adequacy assessments are carried out seasonally, there is a more serious consideration as to whether the assessments are carried out sufficiently completely to capture the rapidly changing risk environment. The underlying analytics of these assessments are not of sufficient breadth to capture what may appear to be low probability events that can occur at any time through the year, not only at the summer or winter peak.

A solution to this shortcoming of current methodologies is to significantly expand the range of potential outcomes that are evaluated using advanced stochastic analytic techniques. While utility planners have long suggested that greater stochastic techniques would be useful, only recently has computing and modeling begun to be able to respond. One such development, Stochastic Nodal

34 ERCOT. 2020. Final Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Winter 2020/2021.

35 2020-2021 Winter Reliability Assessment. November 2020. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2020_2021.pdf

Adequacy Pricing platform (SNAP) is under development in cooperation with MISO.[36] SNAP calculates the probability of inadequacy starting from the output of the day ahead market. Stochastic scenarios of potential outcomes are developed based upon detailed probabilistic forecasts of weather that allow for forecast of wind and solar output and consumer demand from a common base.[37] The value of a potential outage is based upon the Value of Lost Load (VOLL). SNAP is built on existing cloud-based software that identifies and values the probability of combinations of outage events, thus analyzing and valuing hundreds of thousands of possible hourly scenario outcomes.[38]

We strongly advocate the adoption of advanced resource adequacy methodologies and technologies that are capable of evaluation of large numbers of stochastically generated scenarios that incorporate and quantify both common mode events and the probability of extreme events.

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?*

Response:

Please see our earlier responses on Scenario planning and SNAP in answers to questions 7 and 10.

12. *Mass public notification systems (e.g., cellphone texts, emails, smart thermostat notifications) are sometimes used in emergencies to solicit voluntary reductions in the demand for electricity. To what extent are such measures used when faced with emergencies related to climate change or extreme weather events, have they been effective in helping to address emergencies, and is there room for improvement?*

Response:

Public appeals to reduce electric demand have often been used during emergencies and in periods when high demand approaches the capacity of available resources. It can be difficult to evaluate the effect of public requests to reduce demand that are made during an emergency and isolate the effects of public notification from that of other coincident policies. However, a recent field experiment conducted in Japan compared text message requests for voluntary reductions in demand to the impact of time-varying rates. Consistent with economic theory, the experiment found that economic incentives had larger and more persistent impacts than notifications and moral suasion alone.

> "First, moral suasion induces short-run reductions in electricity usage, but the effect diminishes quickly over repeated interventions…. The moral suasion group shows a usage reduction of 8 percent initially. However, their usage become statistically indistinguishable from that of the control group over further interventions. Second, we find that economic incentives create much larger and persistent effects. The economic incentive group shows usage reductions of 14 percent for the lowest critical peak price and usage reductions of 17

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36 Stochastic Nodal Adequacy Pricing platform (SNAP) is under development by Tabors Caramanis Rudkevich, Inc with support from DOE ARPA E Grant DE-AR0001279.

37 Detailed probabilistic weather forecasts are commercially available for SNAP from IBM, The Weather Company.

38 SNAP is built upon the ENELYTIX™ (powered by PSO) cloud-based software system.

percent for the highest critical peak price. Moreover, the effect is much more persistent over repeated interventions…."[39]

Using public notification systems to request demand reductions can produce modest reductions in demand if used infrequently. However, such requests are not a substitute for providing price signals.

The broadcast of notifications that have immediate public safety implications, such as National Weather Service watches and warnings, generally are effective. It could be useful to test whether including messaging on reducing electric demand with the relatively infrequent public notifications of extreme weather could be effective under those conditions.

In addition to encouraging the use of public notification systems to request voluntary demand reductions during emergencies, the Commission should address the communication of pricing information to enhance continuous demand participation. The Commission should consider directing ISOs/RTOs to maintain secure information systems for communicating Day-Ahead prices and Look-Ahead price forecasts in machine readable formats for use by retail supplier- and customer-based systems that could provide customized notifications to consumers and by end use intelligent systems and devices in automating the management of flexible demand.

13. *What measures are being considered to improve recovery times following extreme weather event-related outages? For example, are there potential changes to operating procedures, spare equipment inventory, or mutual assistance networks under consideration? What additional steps should be considered to improve recovery times?*

NO RESPONSE

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?*

NO RESPONSE

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?*

NO RESPONSE

16. *Are there opportunities to improve the Commission-approved NERC Reliability Standards in order to address vulnerabilities to the bulk power system due to climate change or extreme*

39 Ito, K., T. Ida, and M. Tanaka. 2018. "Moral Suasion and Economic Incentives: Field Experimental Evidence from Energy Demand," Economic Policy. Vol. 10, No. 1.

weather events in areas including but not limited to the following: transmission planning, bulk power system operations, bulk power system maintenance, emergency operations, and black start restoration? For example, should the Reliability Standards require transmission owners, operators or others to take additional steps to maintain reliability of the bulk power system in high wildfire or storm surge risk areas? Should the Reliability Standards require the application of new technologies to address vulnerabilities related to extreme weather events, such as to use new technologies to inspect the bulk power system remotely?

Please see response to Question 10.

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?

Response:

We encourage the Commission to work collaboratively with the States in addressing climate change, extreme weather, and maintaining electric reliability. The Commission has a range of available options. For several years starting in 2007, FERC and the National Association of Regulatory Utility Commissioners (NARUC) sponsored a series of collaboratives on smart grid and demand response. Federal law allows FERC to confer and hold joint hearings with State regulatory commissions. 16 U.S.C. §824h(b). This was done, for example, when both FERC and State commissions were considering whether to adopt certain smart grid interoperability standards. Alternatively, FERC could formally convene and refer specific questions to a joint board. 16 U.S.C. §824h(a).

Respectfully submitted April 15, 2021,

Paul Centolella
Mark Gildersleeve
Alex Rudkevich
Ira Shavel
Richard Tabors

APPENDIX A

Follow the link below to download the EPRI report, Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy.

https://www.epri.com/research/products/000000003002019300

APPENDIX B

Tabors Caramanis Rudkevich

Paul Centolella

Paul Centolella is a Senior Consultant in the energy and economics consulting firm Tabors Caramanis Rudkevich and President of Paul Centolella & Associates. With more than 35 years of experience in energy economics, law, and regulation, his work has contributed to the development of environmental cap and trade systems, the design of organized regional power markets, advances in grid modernization and standards development, and the evolution of utility business and regulatory models.

A Commissioner on the Public Utilities Commission of Ohio, Mr. Centolella has served on various national advisory committees including: as Chairman of the National Institute of Standards and Technology's Smart Grid Advisory Committee, on the U.S. Department of Energy's Electricity Advisory Committee where he was Chair of the Smart Grid Subcommittee, the National Academy of Sciences Committee on Determinants of Market Adoption of Advanced Energy Efficiency and Clean Energy Technologies, the Board of the Organization of PJM States where he served as Vice President, the Electric Power Research Institute's Advisory Council including as a member the Council's Executive Committee, the Board of the Smart Grid Interoperability Panel, Americans for a Clean Energy Grid Expert Advisory Counsel, and the MIT's Utility of the Future Advisory Committee. He is currently a member of the National Regulatory Research Institute's Regulatory Training Advisory Board.

Mr. Centolella received his Bachelor's degree with Honors in Economics from Oberlin College and has a J.D. degree from the University of Michigan Law School.

Mark Gildersleeve

Mark Gildersleeve is an economist by training, and currently leads weather impact projects in the energy and transportation sectors. Mr. Gildersleeve served as the President of WSI Corporation, a weather information services company dedicated to enterprise clients, for twenty-eight years from 1991 to 2019. At WSI, and then with subsequent owners (first with The Weather Company, and then with IBM Corporation), Mr. Gildersleeve grew WSI to become the largest private business to business weather enterprise in the U.S. During his tenure, Mr. Gildersleeve led WSI to a leadership position in Media, Aviation, and Energy Trading markets, and he later led WSI's expansion into Insurance, Retail, Ground Transportation, and Government starting in 2016. During his tenure, WSI expanded its range of professional services first into weather forecasting, then into forecasting the impact of weather in different industries on business outcomes, and finishing with the launch of probabilistic weather forecasts.

Prior to WSI, Mark spent thirteen years from 1979 – 1991 in a variety of management positions at the minicomputer company Wang Laboratories ranging across strategy, finance, product management, and marketing. Mark began his career at Charles River Associates working in antitrust litigation. Mr. Gildersleeve received his Bachelor's degree with Honors and Distinction in Economics from Colby College, and has a Masters degree from the University of Chicago with a specialization in industrial organization.

Dr. Alex Rudkevich

Dr. Rudkevich is a partner and co-founder of Tabors Caramanis Rudkevich since 2014 and the President and co-founder of Newton Energy Group, LLC since 2012.

He is an expert in energy economics, regulatory policy, and quantitative analyses of market fundamentals for electric power, natural gas and crude oil production and supply. In the course of his career he designed, directed and managed applied projects and studies involving complex modeling of energy systems with applications to valuation of physical assets; price forecasting policy analyses; and market design.

Prior to forming Newton Energy Group in 2012, he was a vice president with the Energy & Environment practice at Charles River Associates (CRA), Director of Modeling with Tabors Caramanis & Associates (TCA) and held positions in other consulting and academic institutions in the US and Russia. Alex has Ph.D, in Energy Economics and Technology from Melentiev Energy Systems Institute in Irkutsk and M.S. in Applied Mathematics from Gubkin Russian State University of Oil and Gas in Moscow, Russia.

Dr. Ira Shavel

Dr. Shavel is an energy economist with over 40 years of experience in the energy industry, specializing in the economics and operations of electric power systems, generation and transmission investment, and environmental compliance strategy. He has performed work for a wide range of clients, including generation and transmission companies, market operators, natural gas pipelines, energy marketers, industry research groups, as well as federal agencies.

Dr. Shavel has broad experience in the development and use of power system models. He has directed significant assignments for major electric utilities, independent transmission companies, independent power producers, and private equity on matters such as power plant valuation and appraisals, coal plant retirements, fuel and wholesale price forecasting, and the benefits of new transmission lines.

Dr. Shavel has testified before the Federal Energy Regulatory Commission (FERC), state regulatory agencies, US Federal Courts, the Ontario Energy Board, and the Michigan Tax Tribunal.

Dr. Shavel was Principal at the Brattle Group until he retired from Brattle in September 2018. Prior to Brattle, he was a Vice President at Charles River Associates (CRA), a Vice President at Putnam Hayes and Bartlett, and a Vice President at ICF.

Dr. Richard Tabors

Dr. Tabors is President of Tabors Caramanis Rudkevich and Executive Vice President of Newgrid. He is an economist and scientist with 40 years of domestic and international experience in energy planning and pricing. Prior to founding TCR in 2014, Dr. Tabors was vice president and Energy Practice leader at Charles River Associates from 2004 to 2012. He was previously founder and president of Tabors Caramanis & Associates from 1988 until its sale to Charles River

Associates in 2004.

Tabors was co-director of the MIT Energy Initiative's Utility of the Future project. Dr. Tabors has provided expert assistance and testimony in numerous energy sector regulatory and arbitration cases at the federal, state, and provincial levels throughout the United States and Canada. He has provided technical assistance on electricity markets and market development to policy makers, utilities, merchant power developers, and transmission companies in North America, Europe, Latin America, Australia, and the Middle East. Dr. Tabors was a member of the MIT team that developed the theory of spot pricing upon which real-time pricing and locational marginal pricing of electricity and transmissions services are based (Spot Pricing of Electricity, Kluwer Academic Publishers, 1988). Dr. Tabors subsequently led teams addressing the restructuring of power markets in the United Kingdom, throughout the United States, and in Canada. Dr. Tabors has held a variety of research and teaching positions at MIT including assistant director of the Laboratory for Electromagnetic and Electronic Systems, associate director of the Technology and Policy master's program. Dr. Tabors is also a visiting professor of Electrical Engineering at the University of Strathclyde, Glasgow, Scotland, and a member of the U.S. National Academy of Engineering.