NATIONAL ACADEMY OF ENGINEERING®

Section 6 – Electric Power/Energy Systems

Workshop

Creating A Sustainable National Electric Infrastructure While Maintaining Reliability and Resiliency of the Grid

Keck Center, 500 5th Street, NW, Room 101, Washington, DC
October 24, 2022

Workshop Planning Committee – Anjan Bose, Vijay Vittal, Jay Giri, Mark Lauby, Chanan Singh, and Murty Bhavaraju

Disclaimer: **The views expressed in this proceedings are those of the authors and not necessarily of the author's organization, the National Academy of Engineering (NAE), or the National Academies of Sciences, Engineering, and Medicine (the National Academies). The perspectives are intended to help inform and stimulate discussion. This publication is not a report of the NAE or the National Academies.**

WORKSHOP REPORT

Creating a Sustainable National Electric Infrastructure While Maintaining Reliability and Resiliency of the Grid

Over the past decade the electric power utilities in the United State of America (USA) have aggressively integrated low- and no-carbon generation resources into the nation's electric grid to achieve renewable portfolio targets set by various state regulators. In recent years, the federal government has also supported this effort through several measures, including tax incentives, research and development funding, and grants. These policy decisions, along with reductions in the cost of inverter and photovoltaic (PV) panel technologies, have made private investments into renewable variable energy resources (VERs) very attractive. For example, proposed projects that are waiting to be implemented in organized markets are currently overwhelmingly variable generation, leaning toward solar resources more than wind. Counter-imposed on this accelerated integration of VERs and with the reduced prices for natural gas, there is a move to shut down coal generation as quickly as possible and replace it with natural gas-fired generation or preferably with wind or solar resources. Customers, thus, are incentivized to install rooftop solar generation and participate in demand side management programs that include both energy efficiency and demand response.

Worldwide trends to slow climate change, along with its resulting impact on weather patterns and environmental conditions, have led countries to adopt decarbonization of the grid as an important priority. While implementation details may differ, electrical storage has been identified as an important component of solutions for addressing variability of renewable generation, even though it alone cannot be counted on for long-duration and widespread extreme weather and environmental conditions. In fact, there is a need for both local resources and transfers of energy across the grid to be provided by low- or no-carbon resources and complement each other. For this to occur, the design of the grid must change to accommodate renewable VERs and electrical storage. This includes integrating potential but unproven technologies, such as small modular nuclear reactors, hydrogen, or fusion energy sources. Coupled with broad electrification across all sectors of end users, these efforts are directed towards driving out carbon-intensity from demand applications and have necessitated coordinated planning of all elements to provide reliable, resilient, safe, and cost-effective electrical energy delivery.

Although the public discussion has mostly centered on changing the generation mix of the grid from mostly fossil-fuel to solar and wind resources, the profound impact that such a change has on the grid's behavior and performance has been discussed mainly among those responsible for the planning and operation of the grid. The non-linear behavior and performance of the grid is a function of the millions of interconnected components that comprise it. The present-day grid has evolved over more than a century and the planning and operation functions have been adapted by engineers over the same timeframe to the evolving changes. If the generation and electrical storage technologies are changed very rapidly as intended, significant attention needs to be paid to identify and study the challenges that will be encountered and to develop new planning and operational processes to represent the behavior and performance of the transforming grid. Electrification of transportation, residential and commercial heating, and other industrial and agricultural sources of carbon will further affect the grid and reliability goals. Enhancing the grid to support higher levels of reliability is essential for the benefits of electrification to be experienced, as society becomes more dependent on electricity for all its energy needs. Optimal integration of renewable VERs requires expanding and modernizing the transmission and distribution (T&D) infrastructure with significant capital and capacity investments.

Presently, ownership of the grid is fragmented and regulated by all the states over which it operates; however, it's planning, and operation is coordinated by the many actors enacting policies, regulations, and standards to ensure grid reliability and resilience. For the near-term, as the present grid transformation takes place, engineers must understand the grid's changing behavior and performance to develop new guidelines for planning and operations. Conversely, for the long-term when the grid is at the intended zero or near zero carbon state, the challenges are expected to be very different. This end point must also be investigated to make the appropriate preparations, thereby requiring further changes in regulations and standards for coordination.

This workshop, held under the auspices of the U.S. National Academy of Engineering, is premised on the belief that adequate attention has not been paid thus far to the technical guidelines and policy issues required to transform the planning and operation of the grid. While the grid is well on its way to being transformed to achieve decarbonization goals, if changes in planning and operations do not keep up with this transformation and its associated increasing uncertainties, the reliability and resilience of the grid could be severely affected. Extreme weather events between 2018 and 2022 that impacted millions of people in California and Texas, serve as timely examples highlighting the inadequacy of traditional planning and operation practices, where uncertainty or unavailability of generation and transmission energy margins impacts the ability of the grid to deliver the energy where it was needed.

Extreme weather events or environmental conditions appear to be a distinct trend that is frequently disrupting the electricity supply. Hurricanes, tornadoes, high and low temperature events, high or low winds, droughts, and forest fires are all parts of this trend. The reliability standards that are used today to plan and operate the grid are preventive in nature and have served the desired intent well. These standards are based on synchronous machines with rotating mass that are directly coupled with the grid. However, these machines are being replaced with inverter-based resources (IBRs) such as wind and solar, which are decoupled from the grid, with IBRs and associated controls requiring tuning to address essential reliability services. The relatively recent focus on "resiliency" is an attempt to consider how best to recover from the damage caused by such extreme events that appear to be happening with increased frequency. As fossil-fired units, which generally have long-term fuel storage on site, are being replaced with VERs, whose output is uncertain, can vary over time, and is sensitive to extreme weather and environmental conditions, it is not surprising that a new perspective is needed on how the grid operates. In fact, emphasis is now being placed on energy being delivered (time and megawatts available) as the output varies over time based on weather and environmental conditions, rather than just capacity (megawatts) where fuel was assumed to be available when reliability studies were performed, and the system operated.

The power industry currently uses many best voluntary practices and mandatory reliability standards for recovery, including emergency operation plans, system restoration coordination, black start resources, and other similar efforts. However, these will need modification, and new reliability standards may be required to assure current or higher levels of resiliency in the future as electricity becomes the dominant energy source. Further, state regulators have developed metrics for resiliency, which may also need to be revisited as the impacts from the loss of electricity increase, particularly when it is the sole source of energy.

The Electric Power/Energy Systems Section (Section 6) of the U.S. National Academy of Engineering organized this one-day workshop to discuss the reliability and resiliency of the transforming grid. The 40 invited experts from industry, government, and academia represented planners, operators, regulators, and researchers. The agenda for the workshop and the list of participants are in the Appendix. Some of the detailed discussions were held in three breakout groups – 1) generation adequacy, 2) planning and operations, and 3) resiliency. The final set of conclusions were generally agreed upon by the entire group of participants.

At the culmination of the workshop the attendees agreed on a list of challenges facing the planning and operation of the nation's electric grid, while the grid architecture is being radically transformed by the rapid changes in the generation technologies, infrastructure investments either delayed or not approved, and the nature of the load resulting from electrification of other sectors (e.g., transportation, commercial, industrial) to decrease overall greenhouse gas emissions. These challenges, in technical, regulatory, and policy areas, are listed here, together with some recommendations to manage the challenges so that the reliability, resiliency, efficiency, and the economy of the electricity supply to society is not disrupted.

1. Regulatory Challenges

The four components of the electric power system, generation-transmission-distribution-load, are regulated differently under the jurisdiction of separate entities. Prior to restructuring of the industry in the late 1990s, most generation was owned by vertically integrated electric utilities that were fully regulated by state regulators. In exchange for an assurance of cost recovery, these state regulated utilities had an obligation to serve. The result was that utilities and state regulators ensured investment in all the elements of the power system to ensure reliability, including the energy supply chain (the fuel system) that serves the generators.

Restructuring unbundled the industry in many areas of the country, with the result that a significant portion of the electrical energy production today comes from merchant generation (sited at both the transmission and distribution levels), which has the opportunity to recover its costs from the FERC or state/provincial regulated wholesale markets, but with

no guarantee of cost recovery. Restructuring and wholesale competition has resulted in significant innovation, cost efficiencies, and emission reductions, but it has also had an outcome on how reliability is achieved, as discussed immediately belw.

The operational performance of merchant generation and demand response providers, for example, is now dependent on various factor including the combined efficacy of NERC/regional/state reliability standards and the performance incentives presented through market designs. Therefore, investors in merchant generators and distributed resources may be motivated to limit investments in reliability/resilience to those that are either required due to mandatory standards, or where they believe their costs can be feasibly recovered with suitable profitability through the market. Currently-effective reliability standards that are sufficient for a vertically integrated industry with low penetrations of variable generation are no longer sufficient for a restructured industry that has high penetrations of VERs interconnected at both the transmission and distribution systems. Reliability standards and market designs are evolving to reflect the changing resource mix, through complex stakeholder and regulatory processes at both the federal and state level. However, due to the complexity of those processes, the standards and market designs are relatively slow to respond to the rapidly changing operational dynamics of the electric power system. Consequently, there are a number of reliability needs that are not yet specified in reliability standards, or specified and priced in electricity market designs.

Despite the disaggregated nature of the regulatory system that sets standards and market rules, the physical reality is that the four components of the power system are synchronously interconnected and events on any one of the components impacts all the others. This is especially true when new generation resources (primarily VERs) are increasingly located in the distribution system. Although there is coordination of the interconnection of generation to the transmission and distribution systems and the centralized regional planning of the transmission system, there is currently little holistic coordination or planning across the four power system components to ensure reliability of the system as a whole.

This disaggregation results in significant reliability risks and inefficiencies. In order to mitigate these risks, FERC, NERC, and the state regulators must harmonize their reliability regulations, and market designs across the four components to ensure continued reliability and resilience of the existing and future bulk power system. Further, recent events have illuminated that energy adequacy is one of the most important dimensions of a resilient power system. Given the variability of the weather, a power system with a high penetration of renewable resources requires significant quantities of stable, controllable balancing energy inputs that can be converted to stable sources of balancing electrical energy. The natural gas system is currently the most significant, long duration, balancing energy input into the electric power system, and its importance is likely to grow during the transition, until such time as it can be replaced by other technologies. Also, the reliability of the gas system, particularly the gas distribution system, is dependent on the reliability of the electric system to support compression (i.e., pressure levels) and end uses of gas consumption. The interdependencies between these two energy subsectors are currently not recognized in reliability standards for either subsector. In summary, the regulatory oversight of the electric transmission and distribution systems and the interstate pipeline and distribution gas systems is too compartmentalized, leading to gaps and significant reliability risks.

The compartmentalization of regulatory responsibilities of the different interdependent and interconnected components of the electric infrastructure and energy subsectors was a logical outcome of the structure of the bulk power system until the second decade of the twenty-first century. Since the 1960s, the power system was characterized by large central station generation with onsite energy storage (hydro, coal, and nuclear), interconnected by long distance, high voltage interstate lines. Electrical power was delivered from the transmission system to local distribution networks. The interconnected grid offered significant benefits by reducing the need for reserve capacity to address unit random failures and ramping up to address changes in generation, demand, and frequency support across the interconnections. However, there were also risks that emanated from this interconnection, which needed to be addressed. This realization spurred the formation of NERC in 1968 after the 1965 blackout. NERC developed voluntary criteria for the planning and operations of the bulk power system to ensure continued reliable operation. This trend continued, along with the advent of markets. The Energy Policy Act of 2005 (EPAct 2005) formalized the need for an Electric Reliability Organization (ERO) after the 2003 cascading blackout emanating from the U.S. Midwest. EPAct 2005 authorized FERC to certify one entity as an ERO (in 2006, FERC certified NERC as the ERO) responsible for developing and enforcing mandatory reliability standards that support the reliability and security of the interconnected bulk power system. The federal reliability statute explicitly excludes facilities used in local distribution and prohibits reliability standards for the expansion of generation and transmission capacity. Thus, the states generally retain jurisdiction for transmission, distribution, and generation siting and construction (except for cooperatives and municipals), while the FERC/NERC has jurisdiction over interstate reliability performance.

Compartmentalization of regulatory oversight could pose a significant obstacle to the development of consistent and overarching regulatory policies and standards that would ensure the reliability, economy, and resiliency of the nation's entire electric infrastructure. Such policies and regulatory standards should incorporate a holistic assessment of the nation's electric infrastructure system including generation no matter where it is interconnected, along with transmission, distribution and loads, as well as interdependencies like those experienced with the natural gas subsector.

Reliability of the bulk power transmission system is regulated by FERC and the ERO since the bulk power system cannot be planned without some knowledge of the generation being interconnected. Requirements to track planned generation and generation adequacy, which are generally based on capacity of the unit, vary across regions and states. There is significant concern, after some recent load curtailments, that resource and energy adequacy are not being tracked accurately. Namely, adequacy was historically tracked when the capacity of a unit was considered at full or some derated state output; however, this analysis did not include fuel conditions, but rather random failures of unit components. The transforming grid, on the other hand, has significant uncertainties under long-term, widespread weather and environmental conditions when loss of fuel/energy sources (wind, cloud cover, smoke, and other similar reasons) or too much fuel (e.g., wind cut-off speeds) occur simultaneously over large areas and long durations. At one time, capacity could be counted upon to provide both the energy and essential reliability services needed to sustain a reliable grid. With VERs, however, capacity is necessary, but not sufficient to guarantee that energy and essential reliability services are available to meet consumer requirements, unless alternative energy sources are planned for, and investments are made to take up these deficits. Simply derating wind or solar capacity over time periods ignores the simultaneous impacts of widespread, long duration weather or environmental conditions.

Reliability of the distribution systems is regulated by the state through state regulators. As mentioned above, in the past the distribution system was a passive receiver of power from the grid, and except for demand side management options, it was not considered in the planning and operation of the bulk power system. But, today, generation sources are increasingly being connected at lower voltages. This not only affects distribution planning and design, but with generation being connected to the transmission and distribution systems, the planning of the two can no longer be done separately and must be coordinated to ensure reliable operation of the bulk power system. Of course, the generation activated on the distribution system can help ameliorate the impact of events on the generation-transmission system, and vice versa. Importantly, the regulatory standards for generation, transmission, distribution, and demand must be harmonized to leverage the gains from VERs on the decarbonization generating resources.

Coordination between FERC, NERC, and state regulators is needed to develop reliability regulations for the entire grid. Although there are 50 separate state regulators, the owners of distribution systems generally follow similar best practices and approaches. State regulators already coordinate on various aspects through the National Association of Regulatory Utility Commissioners (NARUC). Coordination processes between FERC, NERC, and NARUC, therefore, is vital to decide which reliability standards are needed to support the planning and operation of the entire grid.

The above compartmentalization of standard setting and regulatory oversight, coupled with the rapid deployment of new technologies, creates new risks. These risks are compounded by the fact that many of the traditional analytical tools that are used to plan, design, and operate the transmission and distribution systems will not be adequate for the decarbonized, decentralized, and digitalized grid that is envisioned. As many of these analytical tools are guided by reliability standards and rules-of-thumb, such as the generation capacity adequacy requirement of one event per 10 years, or the ability to withstand single contingencies (*N*-1), there is greater urgency to develop new regulatory criteria and standards that contribute to a highly reliable and resilient grid.

Although the electric grid, from generation to load, is very closely coupled and cannot operate without coordination, it is not isolated from the rest of the energy supply chain and is intricately dependent on the fuel supply system, including coal and gas supplies, and the temporal availability and sufficiency of water, solar, and wind energy. Recent disruptions, especially in Europe and Asia, have pointed to the need for more attention to the coordination of these fuel supply chains, and the importance of regulatory agencies that oversee the electric grid that can ensure better coordination of these other energy subsectors. Further, new available alternatives must be considered, such as new long-distance high voltage transmission that can carry energy from where it is available to where it is not.

Although the existing reliability standards have served society well, increased incidences of extreme events, especially weather and environmental conditions, require enhanced reliability standards that address the performance of an evolving resource mix and one that can withstand extreme events, while, at the same time, enhance recovery from such events.

The reliability standards for the electric grid have continued to evolve over the decades to keep up with grid developments. In fact, the rapid pace of decarbonizing the grid is transforming the very nature of its architecture for connecting generation, transmission, distribution, and loads, thanks to the use of many new technologies and increasing interdependencies. Based on this, reliability standards must also be modernized quickly to keep up with the changes. Time is of essence. Recognizing a complete synchronization would likely require Congressional action, the present structure of federal and state regulations will also have to change. These critical policy challenges led to the following recommendations from the workshop participants.

Recommendation:

1. Need federal and state regulatory structure coordination and collaboration. This can be achieved by enhanced coordination between state regulatory agencies, NARUC, and FERC.
2. Need regulatory policies that account for interdependent transmission and distribution planning and operation. Reliability standards for the bulk power system and the distribution system should complement each other. Existing reliability metrics in distribution systems like SAIDI or SAIFI measure resilience; however, there are few to no mandatory reliability standards at the distribution level that address the integration of Inverter Based Resources (IBRs) and local energy storage (e.g. distribution connected batteries). Investment decisions based on these metrics and targeted resilience levels may need to be revisited as climate impacts and fuel uncertainties increase.
3. Energy availability must be addressed within the regulatory process.
4. Consideration of extreme events, climate change, and inclusion of resilience is essential in the formulation of new standards.

2. Policy

Many states and other government entities have established policies like the renewable portfolio standards (RPS). Further, recent actions by the US Federal government have provided incentives and rebates to support accelerated interconnection of VERs. These policies often include dates for shutting down or retiring existing conventional generation plants as well as installing new renewable generation. These scheduled retirements should be carefully examined and coordinated to ensure that sufficient amounts of energy and essential reliability services are adequate, and the system reliability and resiliency are

assured at all times. This does not mean there is a need to slow integration of VERs. Rather, sufficient energy reserves will be needed to address uncertainties resulting from VERs availability. These reserves and essential reliability services can be obtained in a number of ways (e.g., transmission additions, short-term ramping capabilities from bulk electric storage systems, demand-side management, and other such means) if the appropriate incentives are created (either through standards or market incentives) and a sufficient amount of time is provided to allow for the market response. Scheduled retirements also need to be coordinated with interconnected neighboring states as transmission circuits, markets, and balancing areas cross state lines.

Individual states have regulatory authority over the investor owned utilities within their boundary and have taken the lead in decarbonizing the grid by mandating the time-lines towards less dependence on fossil fueled generation. In order to provide the same level of reliability, the replacement of fossil-fired generation plants by solar or wind generation necessitates that renewable generation provide the energy and ancillary services that the fossil generation provided. Because the sun shines and the wind blows only part of the time, the capacity of renewable generation and/or adequate transmission infrastructure must be built to support this requirement, and the excess energy generated must be stored/accessed for the times when the solar radiation or wind is absent. Moreover, the renewable generation and storage must have the ability of providing frequency response and voltage control to the same degree of effectiveness as conventional generation.

Although the engineering needed to provide these equivalent essential reliability services from renewable generation is quite well understood, there are certain aspects that have not been taken into account when these policies were established. It is easy to understand that solar energy can be sold into the market at cheaper prices than fossil when the sun is shining. Industry will also have to buy energy and other ancillary services from storage devices when the sun is not shining, and these prices will be much higher. In addition, the energy storage capacity has to be even higher to support a storage capacity buffer to cover periods when VERs cannot produce. Additionally, if the system is experiencing widespread, long duration conditions, additional sources of energy and essential reliability services will be needed to ensure reliability and that resilience is sustained.

The grid is interconnected, and many organizations operate the grid across state lines. Although energy crossing state boundaries can be measured, many essential reliability services are not always part of the organized market, e.g. inertial stability or voltage control are provided by generators but are not specified in market designs, and therefore these services are not priced, and generators are not compensated for these services. This is further complicated by the fact that different policies in neighboring states makes it difficult to engineer and compensate the reliability of the interconnected system.

There are many forms of energy storage, ranging from fuels to electro-chemical storage in batteries, to hydro generation. The market will select the most efficient form of storage, if the storage requirement is specified. While short duration storage is very efficient for handling day-to-day contingencies and fluctuations, long duration energy storage is critical in ensuring that a resilient power system is able to withstand extreme weather and environmental conditions.

These challenges led to the following recommendations from the workshop participants:

Recommendation:

1. Clear specification of reliability standards for the interconnected power system, such that reliability and resilience is maintained even when neighboring states choose not to coordinate their electric energy policies.
2. Coordination of exit and entry of new capacity is much more difficult in areas that have restructured, because the decision to retire and/or build is voluntary, and not controlled by central planning. Capacity accreditation methods should therefore ensure that new entrants are valued in accordance with their ability to deliver energy when required for grid reliability, and market designs should appropriately value the required reliability services, including ensuring grid reliability and energy adequacy.
3. Organization of reliability standards around the planning, operations planning, and operation timeframes to ensure sufficient amount of energy is available to address predetermined scenarios providing a design and operating basis of the grid.
4. Electrification of transportation, heating and other industrial processes will lead to significant load growth. Most power systems will transition to become winter peaking and/or exhibit much more load volatility between seasons, and day-to-day variability as both production and energy storage becomes further decentralized. Much of this growth is caused by inefficient application of heating sources such as resistive strip (baseboard) heating, or inefficient air conditioner/heat pumps, when cold conditions are experienced, especially in areas which traditionally have not seen extreme cold conditions. Further, decarbonization policies, standards and market designs should account for these dynamics. Development of resilience planning and/or incorporation of enhanced resilience requirements in standards, addressing training and messaging (including consumers) and assuring that interdependent infrastructures (gas, water, transportation) are considered.

3. Markets

Generation is deregulated in large portions of the US and in those areas, electricity is bought and sold on electricity markets. Existing energy, capacity and ancillary services markets are run by the Independent System Operators (ISOs) or Regional Transmission Operators (RTOs) and regulated by FERC. The market rules are being enhanced to integrate distributed resources (generation, controllable loads and storage), recognizing their ability to provide energy, energy reductions (demand response), and ancillary services as well as controllable loads and storage. Determining the best technical and regulatory practices is challenging, and this effort is lagging the pace of evolution of the resourced mix.

As generation resources are being connected to the lower voltage distribution systems, the markets design are being improved to allow these distributed energy resources (DER) to bid into the wholesale market (e.g. FERC Order 2222). Similarly, demand side management (DSM) is a major tool for energy efficiency investments and in managing the peak load periods with demand response on both the transmission and distribution systems, and these active load entities are also looking for ways to participate in the market. The present state of the markets can take into account transmission level congestion issues by explicitly modeling the transmission network in the market clearing process. However, it is not clear that the transmission network models can be extended to include distribution feeder models. The congestion issues of the distribution system may remain invisible to the wholesale market or the bulk power system operator, thus potentially creating significant reliability issues on both the transmission and distribution systems.

With the increased penetration of IBRs it is critical to ensure that IBRs can provide essential reliability services to the electric power system. Traditionally, the power grid has relied on the stored mechanical energy in large generators' rotating masses (inertia) and other tools and technologies such as central control coordination to maintain grid stability and balance during moderate disturbances. As more renewable generation using IBRs without inertia are deployed, there will be a growing potential to see a greater imbalance between generation and load. While conventional, synchronous generators have operating reserve margins and "naturally" compensate for the imbalance, IBRs could react faster than conventional generation in balancing load and generation through improved management and coordination with system needs. Smart inverters need to have reserve margins and be controlled at the system level to effectively balance generation and load, requiring coordination and appropriate market mechanisms. This will require the long-term planners and operational planners change the way they interconnect resources. They will need to design and coordinate controls at the three-phase level, managing the growing complexity, and amplifying the need for innovation in control system, and cyber system research.

Finally, although FERC regulates the electricity markets and the reliability of the bulk power systems, the reliability and operation of the distribution system is under the authority of the state regulatory agencies. The DER and DSM modules connected to the distribution system in aggregate play a major role in the reliability and operation of the bulk power system but are not required to meet NERC reliability or cyber security standards. Either this gap must be addressed, or the bulk power system will have to carry additional reserves to cover larger contingencies.

These challenges led to the following recommendations from the workshop participants:

Recommendation:

1. The integration of the DER and DSM into the market by using third-party aggregators may provide market benefits but can potentially create reliability, resilience, and security issues for the distribution and the bulk power system. The distribution operator must have some oversight of the market results to guard against distribution level congestion, and potential stability challenges. The distribution operator must have direct visibility of the controls being used by third-party aggregators on distribution level DERs and DSM.
2. Coordination of wholesale and retail rate design along with reliability standards is required.
3. Develop incentives for resilience services with renewables and storage.

4. Develop incentives for renewables that interconnected with contributions to reserve margins. Much like “spinning reserves” or “hot-start reserves,” these resources could be quickly pressed into service when reserves are needed to offset losses of energy in other parts of the system.

4. Long Term Planning

The consequence of restructuring was that no single organization had the responsibility to assure resource and energy adequacy. Without knowing the location of generation, transmission planning by the ISOs and transmission owners (TO), is more challenging. FERC, NERC, the states and the ISOs are trying to address these challenges through improvements to both the planning process and the cost allocation methods for assuring cost recovery for investments needed to both enable and transmit clean energy. However, the transmission planning process is generally lagging the speed of the resource transition. This puts pressure during the operations planning and operations timeframes and there have now been instances of loss of load as a result of generation and transmission inadequacies. Extreme climate changes could also significantly impact power systems in the future. Planning that accounts for extreme climate change is a necessity – this implies creating sufficient resilience through the transmission and distribution planning process and resource/energy adequacy standards and mechanisms.

Building of generation and transmission often requires long lead-times because of the permitting and regulatory processes that vary significantly by location. It is not uncommon for projects to take a decade to complete, or worse, to be abandoned. Many of the processes developed for long-term planning of the grid in regions that have not restructured enable planners to plan both the transmission system and the resource mix simultaneously, e.g. the Southwest Area Transmission (SWAT). However, this type of planning is more challenging in regions that have restructured, since the long-term resource mix evolves organically in response to market and policy incentives and can change quickly with lower investments required for renewable VERs. In restructured regions the transmission planning process is evolving to both respond more quickly to the evolution of the resource mix (e.g., through cluster studies), or to proactively address future needs through investment in transmission to enable future renewable generation (so called “public policy” transmission). The need to ensure energy adequacy, or resiliency, is not yet explicitly considered in the transmission planning process in either structured or restructured regions. This may become necessary as uncertainties grow resulting from interconnection of large amounts of renewable VERS, which are impacted by wide-spread, long-duration weather events.

The long term distribution planning is also facing challenges because more variable generation, especially rooftop solar, is being installed. The anticipated increase in electric vehicles and the conversion of other non-electrical energy consumption (e.g. cooking and heating) can also significantly increase distribution line loading.

Recommendation:

1. Advanced stochastic metrics, such as LOLE and HLOLE and acceptable extreme scenarios are needed to plan the future system to support reliable and resilient operation of the bulk power system.
2. Long-term planning should account for and consider the interconnection between regions and off-shore wind projects.
3. Improve coordination between planning and operation at two critical interfaces; a) transmission and distribution and b) electric power systems and gas (and other fuel) systems.
4. Organize reliability standards around the planning, operations planning, and operations timeframes to ensure sufficient amount of energy and essential reliability services are available to address predetermined scenarios providing a design and operating basis for the grid.

5. Technical Challenges

The rapid transformation of the grid is made possible by the introduction of new technologies associated with renewable VERs, bulk electricity storage systems, and a significant portion of the load projected to include electric transportation. The application of these technologies and electricity substitution for other energy sources in commercial and industrial processes will change the nature of the system. Seamless integration of these new technologies requires solving many technical challenges of planning, design, and operation. Moreover, the grid being a system of systems, the addition of numerous new components changes the system behavior.

As described above, IBRs (generation and storage) can balance load and generation quickly if there is reserve margin available. This approach requires the appropriate grid architecture, including control technology to facilitate the transition from traditional forms of generation to carbon-free generation. Smart inverters need to be controlled at the system level to achieve this goal, which requires new tools, significant changes in existing practices, and appropriate communication infrastructure. Three major technical challenges are mentioned here as these have an impact on policies and regulations.

5(a). Modeling and Analysis

Renewable VERs have now become an integral component of the generation mix, and by their very nature are inherently variable and uncertain. Understanding and characterizing the nature of this uncertainty, and how it changes existing practices is important for a range of applications in planning, design, and operation. With their continued evolution, extreme events pose a higher level of significant risk to power system reliability, resiliency, and security, as their output is sensitive to weather and environmental conditions. There is a critical need to accurately model scenarios for extreme events and incorporate them into the planning and operations framework. With the large investment in measurement technology more data is available across interconnections. Use of such data for validation and verifications of models is essential.

As power systems continue to evolve due to increased inter-relationships between the supply segment and the delivery grids, it is becoming increasingly important to plan the system holistically by integrating generation resources and T&D. However, there are no tools and process for integrated generation and T&D planning and investment prioritization.

Ideally, new technologies should not be installed for use until verified models are available for simulation studies. Additionally, the installed technologies must perform as modeled in the simulation studies, or adjustments made to harmonize and rationalize any differences. This has become a serious a problem in the transmission system, as transmission planners need to change the way they validate the new generator's impact on reliability to incorporate three-phase electromechanical or electromagnetic transient models, when in the past they only used positive-sequence models. This has resulted in a number of reliability issues when VERs are not riding through common faults creating serious events and near misses. Further, large quantities of distribution level resources can create unintended reliability consequences at both the distribution system and the transmission system, and these consequences are currently not, or at best poorly, considered in the distribution interconnection process.

Recommendation:

1. Develop a modeling framework for consistent and coordinated integrated decision making of states, ISOs, RTOs, distribution operators and market participants. These tools also need to extend simulations to hybrid electromagnetic transients and phasor domain analysis.
2. Tools for static and dynamic modeling all the new technologies like IBRs, storage devices, new electronic controllers, digital protective devices, communications, and other such components are needed.
3. Develop new tools, practices, and processes for integrated resource and T&D planning and investment prioritization.
4. Training is required so planners can use the new and existing modeling tools.

5(b). Power System Reliability – Energy Availability

Energy availability (otherwise know an energy adequacy) is a critical component of power system reliability. Given the large diversity in both the generation and load in the system and their changing characteristics, metrics, and design based scenarios that support the planning of future systems that in turn support the reliable operation of the bulk power system are needed. These metrics and scenarios need to capture size, duration, and frequency of various weather and environmental condition events. Significant attention must also be placed to consider the role of transmission in the reliability analysis process. The impact of active load shaping through implementation of demand response and energy efficiency investments also needs to be considered. A backbone transmission system can help to smooth out the variability of renewable power through diversity with energy transported from locations that have excess to areas that are deficient. The need for such a backbone and sufficient storage facilities should be studied.

The one day in ten years loss of load probability standard suited system planning needs with large rotating machines, which are fairly independent of fuel concerns and resistant to impacts from extreme weather and environmental conditions and coupled with low penetration of VERs. These assumptions are no longer valid with high penetrations of asynchronous VERs and sensitive gas-fired generating plants.

Probabilistic reliability assessments need to be coupled with extreme design based scenarios to ensure that not only those events of high frequency are addressed, but also the "tail" events, which can have severe impacts, even though they may be low probability.

Recommendation:

1. Revisit the efficacy of one day in ten years loss of load probability standard that is based on daily peak loads, which was in turn based on random failures of large capacity units with little or no consideration of fuel availability.
2. Ensure that both capacity and energy are available to support operation including quantity, and location is important with significant penetration of solar and wind generation
3. Probabilistic reliability assessment must account for the uncertainties in generation and demand and should account for the impacts of both the transmission and distribution systems.
4. Implement grid architecture, with communication infrastructure and smart inverter and grid controls for leveraging reserve margins available from IBRs.

5(c). Power System Reliability - ***N*-1 Contingency Analysis**

The *N*-1 contingency analysis has remained the basis of NERC operating and planning standards since the inception of these standards. With the changing generation and load mix, and the higher incidence of extreme weather events and environmental conditions due to climate change, there is a need to revisit this premise for both transmission and generation contingencies. For example, should ***N-1*** include predetermined extreme weather events and environmental conditions?

Recommendation:

1. Given system uncertainty and need for consideration of *N-k* scenarios, the *N-1* contingency criterion needs to be re-evaluated to account for the strong correlation between contingencies and evolving environmental and weather conditions that the system must operate under.
2. The contingency definitions should be extended from individual components to consider loss of distribution feeders, regional solar or wind, and aggregated load components

6. Resiliency

There are currently no universally accepted metrics for resiliency and no quantitative NERC standards on resiliency. The NERC reliability standards both minimize the probability of an outage and ensures that industry is ready to recover from events. However, they do not

specify how and what duration is acceptable as these investment decisions are made at the state regulatory level. Standards are needed to plan and design the grid to be restored within an agreed upon time after an outage caused by an extreme event. Extreme weather and environmental condition events resulting from climate change are increasing in frequency and intensity as evidenced by long-duration extreme temperatures, droughts that impact hydro availability and wind events caused by more powerful hurricanes and tornadoes. Similarly, standards are needed for withstanding a deliberate cyber-attack, which is quite different in nature than a weather or environmental event.

The value of resilience metrics lies in their ability to be benchmarked and compared across industry participants to facilitate continuous improvements. However, there is no "one-size-fits-all" solution for resilience metrics and investments as they are dependent on various factors (regional, functional, regulatory, and business). Although it is not possible to have simple, industry-accepted resilience metrics addressing all-inclusive events affecting resilience, it is important to identify individual parameters and events and associated system-dependent metrics. Those metrics could be then applied based on pre-defined priority weights and factors and by using the pre-defined framework to facilitate the investment decision process.

The previous five sections also address issues that are applicable to resiliency and several of the recommendations above apply to resiliency. However, because policies, regulations, and standards are not yet universally available for enhancing the resiliency of the grid, it is worth separately emphasizing this point.

Recommendation:

1. Grid resiliency standards, based on pre-defined framework and performance expectations, should be developed for all to follow.
2. Resilience plans for the restoration from extreme events, addressing training and messaging (including consumers) and interdependent infrastructures (gas, water, communication, transportation), should be mandated.
3. Overall T&D grid hardening is needed, including telemetry and solutions such as covered conductors, composite poles, tripping the circuit before the conductor hits the ground.
4. Research is needed to advance additional solutions with the transforming grid.

Appendix

NATIONAL ACADEMY OF ENGINEERING®

Creating A Sustainable National Electric Infrastructure
While Maintaining Reliability and Resiliency of the Grid
Workshop
Keck Center, 500 5th Street, NW, Room 101, Washington, DC
October 24, 2022

Final Agenda

8.00 AM – 8.30 AM	Registration with Breakfast	*Pre-function Area*
8.30 AM – 9.30 AM	Welcome Vijay Vittal, Regents Professor, Arizona State University Introduction Anjan Bose, Regents Professor, Washington State University Mark Lauby, Senior Vice President and Chief Engineering, NERC Vijay Vittal Framework of the workshop and breakout groups	*Room 101*
9.30 AM – 12 PM	Breakout group presentations and discussion	*Room 101, 102, 104*
10.30 AM	Break	*Pre-function Area*
10.45 AM	Discussion continues	*Room 101, 102, 104*
Noon – 1 PM	Lunch	*Pre-function Area*
1 – 2 PM	Continue breakout group discussion and finalize priorities and issues to be addressed.	*Room 101, 102, 104*
2 – 3 PM	Report out from breakout groups	*Room 101*
3.00 PM – 3.30 PM	Break	*Room 103*
3 – 5.00 PM	Wrap up discussion from breakout group input. Prioritize identified issues and challenges for inclusion in workshop report.	*Room 101*

Confirmed Attendees to NAE Section 6 Workshop

No.	Name	Affiliation
1	Derek Bandera	MISO
2	Emanuel Bernabeu	PJM
3	Gil Bindewald III	DOE
4	Anjan Bose	WSU
5	Terry Boston	Grid Protection Alliance
6	Robert Bradish	AEP
7	Daniel Brooks	EPRI
8	Jay Caspary	Contractor to DOE
9	Yonghong Chen	MISO
10	Joe H Chow	RPI
11	Jonathan First	FERC
12	Matthew Gardner	Dominion
13	Jay Giri	Independent Consultant
14	Eduardo Ibanez	GE Gas Power
15	Marija Ilic	MIT
16	Ali Ipakchi	OATI
17	Mark Lauby	NERC
18	Chen-Ching Liu	VPI
19	Clyde Loutan	CAISO
20	James Momoh	Howard University
21	Sasan Mokhtari	OATI
22	Rana Mukerji	NYISO
23	Jens Nedrud	Puget Sound Energy
24	Damir Novosel	Quanta
25	David Ortiz	FERC
26	Thomas Overbye	Texas A&M
27	John Pespisa	SCE
28	Michael Rib	Duke Energy
29	Jim Robb	NERC
30	Pedro Arsuaga Santos	GE Renewables
31	Matt Schuerger	Minnesota PUC
32	Chanan Singh	TAMU
33	Branden Sudduth	WECC
34	Richard Tabors	TCR
35	Paul Turner	GSOC
36	Mani Vadari	Modern Grid Solutions
37	Vijay Vittal	ASU
38	Gordon van Welie	ISO - NE
39	Dan Woodfin	ERCOT
40	Nan Xue	Siemens