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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

# FERC Reliability Technical Conference

## Panel III: Managing the New Grid

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Good morning Commissioners, staff, and guests. My name is John Moura and I am the Director of Reliability Assessments and System Analysis at the North American Electric Reliability Corporation (NERC). Section 215(g) of the Federal Power Act requires the Electric Reliability Organization (ERO) to conduct periodic assessments of the reliability and adequacy of the bulk power system (BPS) in North America. NERC independently assesses and reports on both the actual performance of the BPS as well as the reliability and adequacy across the planning horizon. It is my privilege to update you today on the key findings and recommendations of our reliability assessments that directly relate to challenges that the electric power industry faces in "managing the new grid."

Between our periodic reliability assessments and the annual *State of Reliability Report*, the data, metrics and analysis provide an excellent perspective for not only what has happened on the system, the outlook for the near-term, but true insight into the challenges that lie ahead. Over the years, NERC has highlighted areas of interest ahead of their impact on reliability, raised awareness of the concerns, provided recommendations, and continued to track and monitor their implementation. Whether it is integration of variable energy, gas and electric system interdependency, regulatory initiatives, or essential reliability services (ERSs), NERC analyzes the topics, forecasts impacts, and makes risk-informed recommendations to mitigate risk impacts advising regulators, policymakers, and stakeholders. Collectively, these activities support a learning environment for maintaining the reliable operation of the BPS.

In addition to NERC's traditional reliability assessments such as the annual *Long-Term Reliability Assessment*, NERC prepares detailed performance analysis of emerging risks based upon specific circumstances and available data. The evaluation of early indicators of risk make a compelling case for action when supported by the data and analysis. As an example, a detailed assessment of the Aliso Canyon experience[1] has driven specific actions to further support BPS reliability that would not have been apparent through a more generalized description of gas dependency concerns. As another example, the Blue Cut Fire report on solar inverter issues[2] identified, analyzed, and addressed a latent risk early in their deployment. To effectively support policies and activities necessary to ensure BPS reliability, the ERO Enterprise remains focused on assessing, and analyzing new BPS risks based upon case specific examples of real and potential impacts associated with the changing resource mix, renewable generation, distributed energy resources, digital controls, fuel dependencies, cyber security, and other emerging challenges. In this way, and by

[1] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20Short-Term%20Special%20Assessment%20Gas%20Electric_Final.pdf
[2] 1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report, Southern California 8/16/2016 Event, June 2017

providing spotlights on these risk, NERC enables the integration of new technologies and resources while maintaining a reliable evolution of the BPS throughout the transformation.

### Findings of Recent Reliability Assessments

The North American BPS is undergoing a rapid and significant transformation with ongoing retirements of fossil-fired and nuclear capacity, as well as growth in new natural gas, wind, and solar resources. This shift is caused by several drivers, such as federal, state, and provincial policies, low natural gas prices, electricity market forces, and integration of both distributed and utility-scale renewable resources. The changing resource mix alters the operating characteristics and constraints of the BPS and these changing characteristics must be well understood and incorporated into planning to assure continued reliability. For example, as more natural gas generation is added to the generation mix, is the natural gas transportation and storage system expanding to accommodate the increasing demand? As more inverter-based resources are integrated into the system, how is the supply of ERSs, provision when required, and delivery of frequency response ensured? These are important questions for NERC, FERC, and the industry as the system continues to rapidly change before the totality of impacts are completely understood.

Recent NERC Reliability Assessments have consistently highlighted several emerging reliability issues related to the changing resource mix and can be summarized in five key points:

- As conventional resources retire, sufficient amounts of ERSs must be maintained.
- Higher reliance on natural gas can expose electric generation to fuel supply and delivery vulnerabilities, particularly during extreme weather conditions. Unless steps are taken to assure fuel availability, continued retirements of conventional generating stations can reduce resilience to fuel supply disruptions and should be considered in planning processes.
- Resource flexibility is needed to supplement and offset the variable characteristics of solar and wind generation.
    - Increasing amounts of distributed energy resources changes how the distribution system interacts with the BPS and transforms the distribution system into an active source for energy and ERSs.
- Because the system was designed with large, central-station generation as the primary source of electricity, significant amounts of new transmission may be needed to support renewable resources located far from load centers.

There are some important caveats to NERC's findings.

1. With sufficient analysis and planning, these challenges are manageable. Numerous engineering analyses (and NERC's independent evaluations) have shown that resources connected to the grid through inverters are capable of providing ERSs, provided that fuel and operational constraints are considered. With prudent planning, market adaptation, and alignment of state and federal policies the BPS can remain highly reliable.

2. Geography is a significant factor in determining solutions that can be applied. For example, certain parts of North America benefit from the natural resources used to support the electricity sector—solar in the southwest and hydro in the northeast. Hydro Quebec's massive energy reserves stored in the form of water enables the province to power nearly all of its electricity demand with hydro generation. For Quebec, a diverse resource mix is not the objective—fuel assurance is. However, most areas of North America do not benefit from the natural resources Quebec benefits from and maintaining a diverse resource portfolio is a wise strategy to assure resource availability and flexibility. Without this diversity, the impact of rare events impacting availability of resources on the power system increases and are more likely the result of a common-mode failure impacting multiple generation or transmission facilities (e.g., extreme and prolonged cold weather event leads to freezing generator components, transmission line icing, fuel delivery disruption, etc.). Areas with limited fuel and/or limited resource diversity may be challenged and should increase their attention to resiliency planning, which requires a strong partnership with state regulators. With natural gas generation primed to continue its growth as the leading choice for new and replacement capacity, important distinctions around fuel security need to be incorporated into reliance and long-term planning at states and with market operators.
3. While the reliability objectives are generally consistent, solutions may be very different depending on the market structure in a given region.

## Accommodating Large Amounts of Distributed Energy Resources

NERC expects significant amounts of distributed energy resources (DER) to be installed in the coming years. By 2022, nearly 30 GW are projected and the trend is expected to increase beyond 2022 (see Figure 2). Increasing amounts of DER can change how the distribution system interacts with the BPS and will transform the distribution system into an active source for energy and ERSs. Attention must be paid to potential reliability impacts, the time frame required to address reliability concerns, coordination of ERSs and system protection considerations for both the transmission and distribution system, and the growing importance of information sharing across the transmission-distribution (T-D) interface.

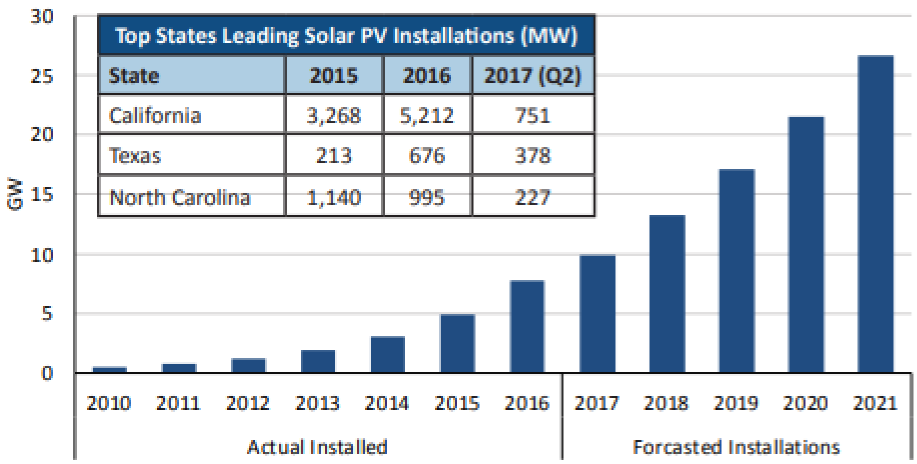


**Figure 2: U.S. Non-Utility PV Cumulative Additions**[3]

Today, the effect of aggregated DER is not fully represented in the BPS models and operating tools. This could result in unanticipated power flows, loss of reactive supply to support the BPS, and increased demand forecast errors. An unexpected loss of aggregated DER could also cause frequency and voltage instability on the BPS at sufficient DER penetrations. Variable output from DER can contribute to ramping and system balancing challenges for system operators who typically do not have control or observability of the DER within the BPS. These issues present challenges for both the operational and planning functions of the BPS. In certain areas, DER are being connected on the distribution system at a rapid pace, sometimes with limited coordination between distribution utilities and BPS planning activities. With the rapid rate of DER installations on distribution systems, it will be necessary for the BPS planning functions to incorporate future DER projections in BPS models, and to ensure operational observability and control is available. These changes will affect not just the flow of power but also the behavior of the system during disturbances. It is important to coordinate the planning, installation, and operation of DER with the BPS.

The NERC Distributed Energy Resources Task Force (DERTF) published a report titled: *Distributed Energy Resources Connection Modeling and Reliability Considerations*, which details the findings of the task force. At a high-level, the conclusions of the report identify the following key areas of focus to ensure reliability:

- **Modeling:** DER are typically netted with load at the distribution bus for operations and planning. The challenge is to understand their variability and interactions with other resources. The electric industry has studied and incorporated the characteristics of conventional resources into the models that are used for planning and operations. To support the reliable integration of DER at higher levels, appropriate modeling methods will be necessary.

- **Ramping and Variability:** Certain types of DER create significant ramps, such as morning and evening solar ramps that are different than historically experienced by the distribution system and the BPS.

[3] GTM U.S. Solar Market Insight – Executive Summary-Q3 2017

Coordination between the BPS and distribution system for planning, installation, and operation of DER resources is a continuing need as the generation resource mix evolves on both transmission and distribution systems

- **Reactive Power:** Currently, most DER are not required to provide reactive support to help control local voltage levels. Modern technologies, including inverters for new rooftop solar PV installations, should have the capability to support voltage and ride-through voltage excursions. Use of these capabilities will be increasingly important to support the reliability of both the transmission and distribution systems.
- **Frequency Ride-Through:** DER are not coordinated with the voltage and frequency ride-through requirements of NERC Standard PRC-024-2. As DER are added to the system, frequency, and voltage ride-through capabilities become important and must be considered both locally and for the BPS. Recent approval of the IEEE Standard 1547-2018 (Revision of 1547-2003)[4] creates harmonized interconnection requirements and offers flexibility in performance requirements for distribution-connected resources.
- **System Protection:** DER are not coordinated with UFLS programs nor are they used to calculate the most severe single contingency and contingency reserve requirements. High levels of DER with inverters can also result in a decline in short circuit current, which can make it more difficult for protection devices to detect and clear system faults. Hence, the implications of DER as part of system protection must be taken into consideration while planning the BPS and distribution systems.
- **Visibility and Control:** Many DER are passive in that they do not follow to a dispatch signal and are generally not visible to the system operator. The lack of visibility and control is not only a challenge for operations, but must also be accounted for in the planning of the BPS At higher penetration levels, DER capabilities related to visibility and control may become increasingly important.
- **Load and Generation Forecasting:** Currently, DER are modeled as load modifiers for most load forecasting tools. However, given the number of DER installation applications and projections of future growth, it may become important to have sufficient information to support forecasting of DER power production separately from load. It will also be important to consider future DER deployment scenarios in the planning of both the distribution systems and the load/generation forecasting systems.
- **Interconnection Requirements:** Interconnection requirements are evolving with increasing DER penetrations, and as a consequence of this, a number of DER classes with very different dynamic behaviors will exist in the BPS. It will be important to know this information, at least in an aggregate way, so that the dynamic characteristics can be modeled correctly for BPS planning.
- **Reliability Standards:** NERC and industry must consider the existing standards, functional model, and related equipment standards in terms of accommodating the growing integration of DER while ensuring prudent planning and Reliable Operation of the BPS. While there are no explicit NERC

[4] IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces: https://standards.ieee.org/findstds/standard/1547-2018.html

requirements to independently model and assess "DER" for purposes of system planning or operations, the transmission operators and transmission planners currently have requirements to accurately model all system components, including "end-use facilities", to address reliability risks.[5] This includes the impact of DER, where material. Current standards (e.g., FAC-001-2, TOP-003-3, IRO-010-2, & MOD-032-1) provide broad authority for system operators and transmission planners to obtain the information needed for models and reliability assessments. This provides the ability to collect pertinent information as related to distribution impacts on the BPS.

## Maintaining ERSs on the BPS

ERSs are vital to the reliable operation of the BPS. In addition to the capacity and energy provided by generation resources, certain physical attributes of electric generation are needed to maintain sufficient levels of frequency response, voltage control, and ramping capabilities. Historically, synchronous conventional generators provided most of the system's ERSs. However, as the BPS evolves to a system that has more variable resources, less synchronous resources, and lower inertia, a careful evaluation of ERSs is warranted. Generating resources must be able to respond to significant changes and rate-of-change in system frequency, provide voltage control in coordination with the Transmission Operator, and be able to support large ramping requirements to balance demand and generation. As the overall resource mix changes, all the aspects of the ERSs must still be provided to support reliable operation. The need for ERSs to support the BPS does not relate to technology deployment. Rather, they are fundamental system characteristics required to support Reliable Operation and must be available regardless of the resource mix composition.

Federal, state, and local jurisdictional policy decisions have a direct influence on changes in the resource mix. As resources retire, in addition to replacing lost capacity, it is necessary for policy decisions to recognize the need for ERSs from the current and future mix of resources. Analyses of these emerging changes must be done to allow for effective planning and provide system operators the flexibility to modify real-time operations for reliability of the grid. Policies need to encourage this type of planning and support the necessary flexibility.

a. Trends in ERSs

NERC publishes trends of ERSs in its annual State of Reliability and Long-Term Reliability Assessment reports. Measures of frequency response and ramping are based on work completed by the Essential Reliability Services Working Group.[6] The *State of Reliability* report publishes system performance data, while the *Long-Term Reliability Assessment* is a forward-looking projection. Some measures, such as those evaluating projected frequency response in a future year, require complex analysis and are still being implemented. NERC expects these to be included for the first time in the *2018 Long-Term Reliability Assessment*.

[5] Facility Interconnection Requirements: https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-001-2.pdf, https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-002-2.pdf
[6] https://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx

In NERC's *2018 State of Reliability* report[7], NERC found that three of the four Interconnections trended "improving" during the arresting period, and two of the four trended "improving" during the stabilizing period. No interconnection experienced frequency response performance below its interconnection frequency response obligation (IFRO). NERC closely monitors the Interconnection frequency response metric (IFRO in the stabilizing period, see Figure 1) as the rapidly changing resource mix must continue to provide sufficient amounts of frequency response.[8]

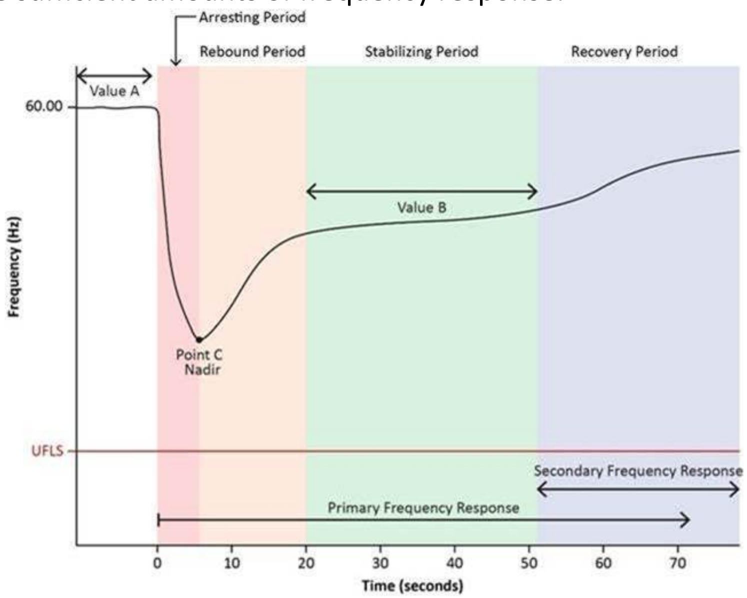


**Figure 1: Visualized Interconnection Frequency Response after the Loss of a Generation Resource**

NERC also emphasizes the importance of maintaining margin between the lowest frequency (nadir) of a loss of generation event (during the arresting period) and the respective interconnection's under frequency load shed (UFLS) set point. UFLS provides a vital BPS safety net; however, BPS operation should occur in such a way to avoid unnecessary UFLS activation.[9] Individual interconnection performance is separated into performance during the arresting period and during the stabilizing period. For the arresting period over the 2013–2017 operating years, the Eastern Interconnection (EI), the Texas Interconnection (TI), and the Québec Interconnection (QI) each had a statistically significant and improving frequency response trend during the arresting period. The Western Interconnection (WI) trend was neither statistically improving nor declining. For the stabilizing period, frequency response over the 2013–2017 operating years indicated that the WI and TI trends experienced statistically significant improvement during the stabilizing period. The EI and QI trends neither statistically improved nor declined.

[7] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_2018_SOR_06202018_Final.pdf
[8] The Essential Reliability Services Task Force Measures Framework Report: http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf
[9] Reliability Standard PRC-006-3 — Automatic Underfrequency Load Shedding can be found at the following location: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-006-3.pdf. In this standard's purpose statement, UFLS is characterized as providing "last resort system preservation measures."

In NERC's *2017 Long-Term Reliability Assessment*, an evaluation of the changing net load patterns identified an increasing need for system flexibility in California. With continued rapid growth of distributed solar, CAISO's three-hour ramping needs are projected to increase to 16 GW by 2020, exceeding earlier projections and reinforcing the need to access more flexible resources. Ramping is related to frequency through balancing during system operations. Changes in the amount of non-dispatchable resources, system constraints, load behaviors, and the generation mix can impact the ramp rates needed to keep the system in balance. For areas with an increasing penetration of non-dispatchable resources, the consideration of system ramping capability is an important component of planning and operations.

The 2017 LTRA identified a potential trend with increasing amounts of reactive power being supplied by nonsynchronous resources such as inverter-based generating resources and transmission-connected dynamic reactive power electronic devices such as static VAR compensators or static synchronous compensators. This trend is resulting from replacement of reactive power support from conventional synchronous resources and classical reactive power sources (e.g., fixed and switched shunts) with inverter based controllers. In the assessment, NERC recommends that the NERC Reliability Standards should be reviewed to ensure they actively account for the performance of emerging technologies that supply reactive power support on the BPS. In 2018, NERC's Planning Committee initiated two actions in response to the recommendations: 1) The Reliability Assessment Subcommittee is tasked to collect projections of reactive resources to understand the magnitude of risk exposure, and; 2) the System Analysis and Modeling Subcommittee is directed to assess Reliability Standards for applicability to transmission-connected reactive controllers, address any potential reliability gaps, and identify potential areas for enhancement.

b. Implementing Solutions to Assure Sufficient ERSs

Operating procedures that recognize potential inertia constraints were recently established in ERCOT and Québec. Due to their smaller size, the ERCOT and Québec Interconnections experience lower system inertia compared to the Eastern and Western Interconnections. Currently, wind amounts to more than 17 percent of installed generation capacity in ERCOT and has served as much as 50 percent of system load during certain periods. In Québec, hydro accounts for over 95 percent of the generation, which generally has lower inertia compared to synchronous generation of the same size (e.g. coal and combined-cycle units). As a result, ERCOT and Québec have both established unique methods to ensure sufficient frequency performance.

In ERCOT, system planners have defined critical inertia levels that must be maintained for the system to operate reliably with current frequency control practices. A series of dynamic simulations were conducted based on cases from ERCOT's Real-Time Transient Security Assessment Tool with inertia conditions ranging from 98 GW to 202 GW to assess how long it takes for frequency to fall from 59.7 Hz to 59.3 Hz after two of the largest units tripped. ERCOT studies show that higher amounts of frequency responsive reserves are needed for low-inertia situations to maintain the security and reliability of the grid. To ensure sufficient response capability is on the system at all times, ERCOT system operators have established a 100 GW/seconds as a critical inertia level that will serve as a constraint within their security constrained economic dispatch management systems. Generation can be curtailed and redispatched to ensure this critical inertia level is maintained.

In comparison to the Québec and ERCOT Interconnections, the Eastern and Western Interconnections are much larger systems with relatively less nonsynchronous generation. For both interconnections, case development and analysis of forward-looking frequency response performance will be completed in 2018 with the results available for the 2018 LTRA. These efforts will lead to future-looking studies for ERSs frequency response measures, which could be repeated every 2–3 years, with 5 year projections (constantly updated with historic data). Both interconnections will provide study reports to NERC with respective study cases. Eastern and Western Interconnections may also develop a procedure manual for this work to be updated in the future on a periodic basis.

Underpinning the work of the industry, NERC's BAL-003-1 Reliability Standard provides the performance expectations of the BPS. The Reliability Standard requires sufficient frequency response from the Balancing Authorities to maintain interconnection frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. The Reliability Standard requires Balancing Authorities to maintain a minimum level of Frequency Response and is measured independently by NERC Staff. Each year, NERC conducts an analysis, calculation, and recommendations for the Interconnection Frequency Response Obligation for each of the four electrical interconnections of North America. This analysis includes a statistical analysis of the historical frequency characteristics, a calculation of adjustment factors from BAL-003-1 frequency response events, an analysis of frequency profiles for each interconnection, and a dynamics analysis validation of the recommended IFRO. While recent evaluations by NERC staff and stakeholders have called for enhancements to the Reliability Standard, the framework for establishing performance expectations based on interconnection-wide engineering studies is highly supported. Under the direction of the Operating Committee, the Resources Subcommittee is actively addressing potential changes to the BAL-003 Reliability Standard to ensure sufficient generator and system performance during frequency excursions. A Standard Authorization Request (SAR) is in place and a project is identified in the Reliability Standards Development Plan for 2018-2020.

In addition to NERC's Reliability Standard, FERC's recent action through Order No. 842 now requires all new generating facilities install, maintain, and operate a functioning governor or equivalent controls as a precondition of interconnection. FERC's changes to the *pro forma* Small and Large Interconnection Agreements provide a turning point for ensuring that all resources are capable of providing frequency response, and ERSs. The FERC order does not impose performance requirements and thus system operators and electricity markets must be able to incentivize or require performance. In wholesale market areas, market products have been created and continue to evolve.

c. August 2016 Blue Cut Fire and October 2017 Canyon Fire events

NERC's *State of Reliability 2017* reported that an unplanned loss of approximately 1,200 MW of solar inverter-based resources occurred in August 2016 in the WI. A joint NERC/WECC task force analyzed that event and produced a report,[10] resulting in a Level 2 NERC Alert to industry issued on June 20, 2017. The analysis revealed two major issues with solar PV inverter-based resources. First, a specific manufacturers' inverters were susceptible to erroneous frequency tripping during transmission faults. The manufacturer devised a solution, and the recommendation advised registered entities to contact the inverter manufacturer and implement the changes. Second, manufacturers' inverters employ an operating characteristic in general during abnormal grid voltages referred to as momentary cessation. During cessation, the inverter ceases to inject current into or draw current from the grid. The recommendation advised registered entities to configure inverters so they will restore output no more than five seconds after cessation is initiated.

The analysis identified the need for further studies to determine impacts of momentary cessation on reliability as well as other inverter issues that impact the stability of the Interconnections. The NERC Operating Committee and Planning Committee created a joint task force, the Inverter-Based Resource Performance Task Force (IRPTF) in June 2017, to perform that work. The task force is producing a guideline for inverter-based resource performance to support BPS reliability.[11]

Another incident occurred in the WI in October 2017. The NERC report[12] on that disturbance was published in February 2018, and it revealed new inverter-based resource performance issues that are being addressed with a follow up to the first NERC Alert: Recommendation to Industry (Loss of Solar Resources during Transmission Disturbances – II).[13] This Recommendation advises entities to do the following:

- Ensure inverters will not trip on transient overvoltage (specific thresholds and guidance are under development).
- Eliminate inverter use of momentary cessation if possible.
- Inject reactive current as necessary to mitigate cases of low voltage.
- In cases for which momentary cessation cannot be eliminated do the following:
  - Reduce the momentary cessation low voltage threshold to the lowest value possible.
  - Reduce the recovery delay to the smallest time period possible.
  - Increase the active power ramp rate to at least 100 percent per second (i.e., return to pre-disturbance active current injection within one second).
- Coordinate facility and inverter controls to not impede restoration from momentary cessation.

[10] The 1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance report can be found at the following location: https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.
[11] The IRPTF can be found at the following location: https://www.nerc.com/comm/PC/Pages/Inverter-Based-Resource-Performance-TaskForce.aspx
[12] The 900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance report can be found at the following location: https://www.nerc.com/pa/rrm/ea/Pages/October-9-2017-Canyon-2-Fire-Disturbance-Report.aspx.
[13] The alert can be found at the following location: https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf

Bringing technical experts together is one of the most effective approaches to remedy this issue, and once corrected enables higher levels of inverter-based resources to be integrated. NERC's IRPTF is actively engaged in addressing inverter performance and is supported by a cross-section of industry stakeholders including manufacturers, generation owners, and transmission planners. The task force builds off of the experience and lessons learned from the ad hoc task force created to investigate the loss of solar PV resources during the Blue Cut Fire event and other fault-induced solar PV resource loss events. The task force is addressing many of the recommendations from the Blue Cut Fire Disturbance Report, including additional system analysis, modeling, and review of inverter behavior under abnormal system conditions. Recommended performance characteristics will be developed along with other recommendations related to inverter-based resource performance, analysis, and modeling. The technical materials are intended to support the utility industry, Generator Owners with inverter-based resources, and equipment manufacturers by clearly articulating recommended performance characteristics, ensuring reliability through detailed system studies, and ensuring dynamic modeling capability and practices that support BPS reliability. The task force will develop a Reliability Guideline to address resource performance by the end of 2018. In addition to the task force work, NERC, North American Transmission Forum (NATF), North American Generator Forum (NAGF), Energy Systems Integration Group (ESIG), and Electric Power Research Institute (EPRI) are conducting webinars to inform industry on desired performance outcomes and inverter settings to achieve them. These have been widely attended and there is significant interest in understanding and mitigating the identified technical challenges.

## Conclusion

As the ERO, NERC has a responsibility, working with industry experts and other stakeholders, to identify new and emerging risks to reliability. NERC continues to examine impacts on the BPS related to the changing resource mix. Reliably integrating high levels of variable resources (wind, solar, and some forms of hydro) into the BPS will require significant changes to traditional methods used for system planning and operation. The amount of variable renewable generation is expected to grow considerably as policy and regulations on greenhouse gas emissions are being developed and implemented by federal authorities and individual states and provinces throughout North America. Power system planners must consider the impacts of variable generation in power system planning and design and develop the necessary practices and methods to maintain long-term BPS reliability. Operators will require new tools and practices, including potential enhancements to NERC reliability standards or guidelines to maintain BPS reliability. As a key element of the ERO's mission, NERC remains keenly focused on identifying emerging risk in order to maintain a proactive posture to ensure that the BPS remains highly reliable.