

June 5, 2012

Regional Entity Executives

Follow-Up Actions for September 8, 2011 Southwestern Blackout

The [NERC/FERC Joint Staff Inquiry report on the Arizona – Southern California Outages on September 8, 2011](#) contains various findings and recommendations that are specifically applicable to Registered Entities in WECC, including the Reliability Coordinator (RC), Transmission Owners (TOs), Transmission Operators (TOPs), Generation Owners (GOs), Generation Operators (GOPs), Transmission Planners (TPs), Planning Coordinators (PCs), Balancing Authorities (BAs), and Distribution Providers (DPs).

Some of these findings and recommendations may nonetheless be applicable to Registered Entities in the Eastern and Texas Interconnections. Therefore, NERC requests that each Regional Entity provide a status report on the actions by Registered Entities, technical committees, or other work groups within your Regional Entity footprint to address the applicable findings and recommendations from the report. Please identify any action plans with applicable Registered Entities, technical committees, or work groups in your response. Given the timing of the summer peak season, your timely response is necessary.

Attachment I to this letter divides the findings and recommendations into two groups:

Group A — Next-Day and Real-Time Operating Issues

Group B — Longer-Term and Seasonal Planning Issues

For Group A, please provide a preliminary report to NERC within 30 days of receipt of this letter, and a final report with completed and to be completed actions from the applicable registered entities, technical committees, or work groups within 60 days. For Group B, responses should be provided by September 1, 2012. The specific questions associated with the recommendations are included to help guide your assessment and responses. In considering the findings and recommendations, you may think of other questions, and are encouraged to include them in your responses.

I also sent a copy of this letter to the officers of the NERC Planning and Operating Committees and ask that they engage in reviewing the report's findings and recommendations from a North American perspective. Finally, a copy of this letter is being sent to the North American Transmission Forum for their information and consideration.

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Thank you in advance for your cooperation in responding to this important request. If you have any questions or encounter barriers in completing this request, please contact me.

Sincerely,

A handwritten signature in black ink, appearing to read "D. R. Nevius".

David R. Nevius
Senior Vice President, NERC

cc: NERC Planning and Operating Committee Officers
Tom Galloway, President and CEO, North American Transmission Forum

Attachment I — Key Categories of Findings and Recommendations to be Addressed

Group A: Next-Day and Real-Time Operating Issues

Recommendations 1 – 4 address the responsibilities of RCs, TOPs, and BAs in the **next-day planning** timeframe. They stress the importance of accuracy in next-day planning models, including sharing, across the entire RC footprint, generation and transmission outages and transactions that could impact the reliability of the bulk power system (BPS); comprehensiveness of studies with respect to facilities that can impact bulk power system reliability, including sub-100 kV facilities; and the free and unrestricted exchange of next-day operations data and studies between and among operating reliability entities.

1. Do the TOPs in your region update next-day studies to reflect known outages and current system conditions? Are the next-day studies available to neighboring TOPs, including the status of planned outages of generation and transmission, and expected transactions?
2. Have TOPs and RCs completed studies identifying the sub-100 kV facilities that could, under severe or unusual conditions, have significant impacts on BPS reliability and model those facilities in their next-day studies? Are studies performed to evaluate the effect on sub-100 kV facilities when new transmission or generation facilities are added to the system?

Recommendations 11 – 16 cover a broad range of **situational awareness** issues, including: real-time visibility of external systems; adequacy of real-time tools; reliance on post-contingency mitigation measures; communicating the need for backup when Real-Time Contingency Analysis (RTCA) capabilities are lost or impaired; and inconsistencies between real-time and planning models.

1. Do the TOPs and RCs in your area have RTCA tools that provide visibility of external systems?
2. To what extent do TOPs in your region rely on other entities to perform real-time analyses for them?
3. To what extent have the TOPs in your region incorporated the recommendations of the [NERC Real-Time Tools Best Practices Task Force](#)?
4. What steps are taken to ensure consistency between real-time and planning models?
5. To what extent do any of your TOPs rely on post-contingency mitigation measures? If so, how are these measures evaluated to ensure they do not lead to cascading outages under severe or unusual system conditions? Are affected neighbors notified of possible ramifications of these post-contingency measures?

Recommendation 17 addresses the need for consideration, both in advanced studies and in real-time operations, of **sub-100 kV facilities** operated in parallel with the BPS that can have an impact on bulk power system reliability.

1. What steps are taken to ensure that sub-100 kV facilities that could impact bulk power system reliability are considered in both real-time and advanced studies, especially during severe or unusual system conditions?

Recommendation 18 refers to the identification and recognition of **Interconnection Reliability Operating Limits¹ (IROLs)**, both in day-ahead studies and in real-time operations.

1. What procedures are used to identify IROLs within your region and how are these limits shared and coordinated within the region and with neighboring regions?

Recommendations 19 – 26 address multiple issues related to **protection systems**, including: regular review, analysis, and coordination of special protection systems with and among interconnected systems, especially under adverse system conditions; sensitivity of turbine control systems during extreme events; communicating to neighboring systems and RCs equipment overload relay settings that are below or only marginally above applicable ratings; reflecting overload relay settings in the determination of System Operating Limits (SOLs).

1. Do TOPs share with their respective RC and neighboring TOPs overload relay trip settings on transformers and transmission lines that could impact the reliability of the BPS?
2. Do TOs use overload trip settings below 150 percent of the normal rating or below 115 percent of the highest emergency rating, whichever of these two values is greater? If these conditions exist, do TOPs share their operating procedures for mitigating the problem? Are these operating procedures pre or post contingency and, if post contingency, is there enough time for operators to initiate the procedures based on the time delays associated with the relay settings?
3. How frequently are special protection systems in your region reviewed for their continued necessity and their coordination with other similar systems and within the interconnection? Do these reviews evaluate the consequences of inadvertent operation of special protection systems?
4. What efforts are underway to evaluate the performance of generators under severe or unusual system conditions, especially with regard to the behavior of turbine control systems and underfrequency relay coordination?

Recommendation 27 addresses the need for tools to determine, in advance of contingencies, the **angular separation** following line trips under a wide range of system conditions, as well as the need for plans for reclosing lines with large phase angle differences.

¹ NERC Glossary Definition of IROL: A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Power System.

1. Do TOPs and RCs have the ability to determine, in real time, the standing angles that would result following major transmission line outages?
2. Are there PMUs or PMU-capable digital relays located and streaming data such that post-contingency angles can be seen directly in SCADA/EMS systems?
3. Do RCs have predetermined plans for reducing angles to within synchro-check relay settings to allow prompt reclosing of lines?

Group B: Longer-Term and Seasonal Planning Issues

Recommendations 5 – 8 address the responsibilities of TOPs for **seasonal planning**, especially in terms expanding the scope of their seasonal planning studies to include external facilities and the impact of sub-100 kV facilities, both internal and external to the TOP's system, on bulk power system reliability. The recommendations also stress the importance of sharing information with neighboring TOPs and the RC regarding overload relay trip settings that fall below or near the emergency ratings of their facilities.

1. How are TOPs in your region alerted to planned outages external to their systems?
2. Do seasonal studies evaluate your entire regional footprint whereby TOPs can see the effect on one area from a contingency occurring in another area? If not, how does your seasonal planning process ensure there are no study gaps/seams between parts of the region?
3. In the Eastern Interconnection, how is coordination performed with neighboring regions to ensure the effects of a contingency in one region are known by neighboring regions?
4. In the seasonal study process are appropriate elements, including those below 100 kV that can affect the reliability of the BPS, studied in contingency analysis?
5. Are seasonal studies performed for shoulder periods such as spring and fall when transmission elements and generators may be scheduled out of service for maintenance?

Recommendations 9 – 10 focus on the importance of addressing gaps in the **planning processes** of REs, TPs, and PCs, especially where these gaps result in a lack of consideration for critical system conditions, impact of sub-100 kV facilities, interaction of protection systems, and failure to benchmark models against actual system conditions that occur during unusual system events.

1. Do the near- and long-term planning studies conducted by TPs and PCs evaluate the impacts of major transmission outages under heavy transfer conditions?
2. Do these studies evaluate the impact of such outages on sub-100 kV facilities, especially those operated in parallel with the BPS, to determine whether any potential exists for system cascading?
3. How do the PCs in the Region ensure that near- and long-term planning studies address the interaction of various protection systems, especially special protection systems that are designed to operate post-contingency?

4. Are models benchmarked against real system conditions, especially severe and unusual system conditions?
5. Do system dynamic studies take into account relay and UFLS schemes?