Wisconsin's Electrical System Response
to the
August 14, 2003, Lake Erie Loop Cascading Electric System Outage

Final Report
to
Governor James Doyle
and the
Wisconsin Legislature

by the
Wisconsin Public Service Commission

May 27, 2004

Introduction

On September 15, 2003, the Public Service Commission (Commission) issued an *Interim Report on Wisconsin's Electrical System Response to the August 14, 2003, Lake Erie Loop Cascading Electric System Outage.* This is the Final Report by the Commission on that event. It contains an overview of the U.S.-Canada Power System Outage Joint Task Force's *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* issued April 2004 (the Joint Task Force Final Report). It also contains an overview of responses subsequent to the August 2003 blackout by the Federal Energy Regulatory Commission (FERC),[1] the North American Electric Reliability Council (NERC),[2] and the Midwest Independent Transmission Operator (MISO).[3] Further, it includes observations as to the Commission's ongoing regulation of Wisconsin electric utilities in light of the August 2003 blackout and the Joint Task Force Final Report.

Summary of US-Canada Power System Outage Joint Task Force Final Report

Blackout Event Summary

At 12:15 p.m. Eastern Daylight Time (EDT), on August 14, 2003, MISO operators detected that one of MISO's system monitoring tools, called its State Estimator,[4] was not producing a correct

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[1] FERC is the independent federal agency that, among other responsibilities, regulates the transmission and wholesale sales of electricity in interstate commerce.
[2] NERC is a not-for-profit company formed by the electric utility industry in 1968, following the 1965 New York electric system blackout, to promote the reliability of the electricity supply in North America through the voluntary use of common planning and operating guidelines.
[3] MISO is the Regional Transmission Organization (RTO), headquartered in Carmel, Indiana, covering all or parts of 11 states in the upper Midwest including Wisconsin, that has oversight responsibilities for a peak demand of over 100,000 MW. It has the responsibility to monitor power flows and to ensure the reliability of the electric generation and transmission throughout that area.
[4] The State Estimator is a computer model that uses real-time voltage information from the electric system to confirm whether the system is operating in a secure state. It also analyzes the system for outages of transmission lines or generating units that could result in loss of load. The State Estimator models system condition every five minutes.

representation of the real-time status of the transmission system. MISO corrected that problem but failed to return the State Estimator to automatic run mode. As a result, MISO was not aware of and could not accurately assess potential system problems that were beginning to develop.

First Energy's (FE) Eastlake 5 generator tripped off line at 1:31 p.m. EDT to protect itself from operator demands that were greater than its output capability. FE's dispatching control room's alarm and event logging failed at 2:14 p.m. EDT and was not restored. As a result, system operators were not made aware of major outages and resulting degradation of system conditions.

Beginning at about 3:06 p.m. EDT, FE's Harding-Chamberlin 345 kV transmission line and two other FE 345 kV lines tripped out of service when they came in contact with trees that had encroached into the required clearance height for the lines. Power flows on those lines were at or below their emergency line ratings at the time of tree contact. MISO and other reliability coordinators called the FE control room to confirm line outage indications. At that time, proactive and significant load shedding in the order of 1,500 MW might have averted further blackouts.

After 3:45 p.m. EDT, several 345 kV lines and 138 kV lines cascaded out of service due to heavy power flows which caused tree contacts from sagging and other problems. The loss of those 138 kV lines led to the tripping of FE's Sammis-Star 345 kV line at 4:06 EDT. This event started the rapid uncontrollable cascading outages of other transmission lines and generators. The lines and generating units were automatically tripped by their protective relay devices to avoid physical damage.

By 4:13 p.m. EDT the cascading had stopped after affecting 50 million people by the loss of 61,800 MW of load in Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey, and the Canadian province of Ontario. Power was not restored to some areas until four days later and some parts of Ontario continued with rolling blackouts for more than a week until full power was restored. The estimated total costs in the United States ranged from $4 billion to $10 billion. In Canada, the gross domestic product was down 0.7%, with 18.9 million work hours lost, and manufacturing shipments in Ontario were down $2.3 billion (Canadian dollars).

Causes of the Blackout and Related Violations of NERC Standards

The Joint Task Force Final Report indicates that four specific groups of causes were identified that contributed to the blackout. These causes generally constitute previously existing institutional weaknesses or failures that will need to be corrected to improve reliability. For instance, lack of reactive power was not the cause itself, but the lack of adherence to industry policies and the management of reactive power and voltage contributed to the cause of the blackout.

NERC has determined that several violations of its policies regarding reliability requirements[5] addressing standard operating procedures of control area operators, and reliability coordinators,

[5] The NERC operating policies are based on the premise that all control areas share the benefits of interconnected systems operation through their participation in NERC, and they recognize the need to operate in a manner that will

occurred in the events leading to the blackout. NERC noted, however, that some of these requirements were not clear as to what would constitute adequate compliance. At this time, there are no monetary penalties or other consequences to NERC policy violations.

The four specific categories of causes are listed below along with a brief overview and an indication of the related NERC violations. The Joint Task Force Final Report contains greater detail on the causes and explanations.

Cause 1: Inadequate System Understanding

FE and East Central Area Reliability Coordination Agreement (ECAR)[6] failed to assess and understand the inadequacies of FE's system and the ability to maintain adequate voltages in the area. FE did not operate its system within appropriate voltage criteria.

FE did not conduct rigorous studies of its system and neglected to conduct multiple contingencies or extreme condition assessments. FE did not conduct sufficient voltage analysis for the Ohio control areas and ECAR did not conduct an independent review or analysis of FE voltage criteria. Some of the NERC planning and operational requirements and standards were sufficiently ambiguous that FE interpreted them in such a way as to allow practices that, in fact, were inadequate for reliable system operation.

Cause 2: Inadequate Situational Awareness

FE did not recognize or understand the deteriorating condition of its system prior to the blackout and did not use effective contingency analysis capability on a routine basis. It did not have procedures to ensure its operators were aware of the functional state of their monitoring tools. Further, it did not have additional back-up monitoring tools to understand or visualize the status of their system.

Related NERC violations:

FE's operational monitoring equipment was not adequate to alert FE's operators regarding important deviations in operating conditions and the need for corrective action as required by NERC Policy 4, Section A, Requirement 5.

FE's state estimation and contingency analysis tools were not used to assess system conditions, violating NERC Operating Policy 5, Section C, Requirement 3, and Policy 4, Section A, Requirement 5.

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promote reliability in interconnected operation and not burden other entities within their interconnection. NERC's doctrine for interconnected systems operation consists of standards, requirements, and guides. Together, these form the operating policies.

[6] ECAR is the reliability coordinator responsible for all or parts of nine east-central states including, among others, Ohio, Indiana, lower Michigan, and western Pennsylvania.

Cause 3: Inadequate Tree Trimming

FE failed to manage the tree growth in its transmission rights-of-way. This failure was the common cause of the outage of three FE 345 kV transmission lines and affected several 138 kV lines. FE failed to maintain the equipment ratings through a vegetation management program which is a control area requirement in the NERC policies. However the requirements are not clearly defined in the NERC standards and policies.

Cause 4: Inadequate Reliability Organizations Diagnostic Support

MISO did not have one of the key 345 kV lines in the eastern area incorporated into its state estimator thus preventing MISO from being aware of the problems earlier. MISO was not using real-time data to support real-time “flow-gate” monitoring and this prevented them from determining first contingency security violations. MISO and PJM Interconnection, LLC (PJM) lacked joint procedures on how to deal with security limit violations observed by either MISO or PJM in the other’s respective area due to a contingency near their common interface. MISO was the reliability coordinator for FE on August 14, but FE was not signatory to the MISO Transmission Owners Agreement and was not operating under the MISO tariff, so MISO did not have the full authority over FE as required by NERC Policy 9. American Electric Power and PJM tried to address the escalating transmission power flow problems by curtailing or restricting transmission transactions, but those actions were not sufficient to control the problem.

Related NERC violations:

Following the outage of the Chamberlin-Harding 345 kV, FE operation personnel did not take the necessary actions to return the system to a safe operating state as required by NERC Policy 2, Section A, Standard 1.

FE operations personnel did not adequately communicate its emergency operating conditions to neighboring systems as required by NERC Policy 5, Section A.

MISO did not notify other reliability coordinators of potential system problems as required by NERC Policy 9, Section C, Requirement 2.

MISO was using non-real-time data to support real-time operations, in violation of NERC Policy 9, Appendix D, Section A, Criteria 5.2.

PJM and MISO as reliability coordinators lacked procedures or guidelines between their respective organizations regarding the coordination of actions to address an operating security limit violation observed by one of them in the other’s area due to a contingency near their common boundary, as required by Policy 9, Appendix C. Note Policy 9 lacks specifics on what constitutes coordinated procedures and training.

Joint Task Force Recommendations

The Joint Task Force noted that the blackout had similar characteristics to earlier large, cascading blackouts. Efforts to implement earlier recommendations have not been adequate to prevent very large scale events. The Joint Task Force's recommendations address the inadequacies of responses to earlier blackouts and emphasize comprehensiveness, monitoring, training, and enforcement of reliability standards.

The recommendations presented can be described as having four broad themes. The following is an except from the Joint Task Force Final Report:

1. Government bodies in the U.S. and Canada, regulators, the North American electricity industry, and related organizations should commit themselves to making adherence to high reliability standards paramount in the planning, design, and operation of North America's vast bulk power systems. Market mechanisms should be used where possible, but in circumstances where conflicts between reliability and commercial objective cannot be reconciled, they must be resolved in favor of high reliability.
2. Regulators and consumers should recognize that reliability is not free, and that maintaining it requires ongoing investments and operational expenditures by many parties. Regulated companies will not make such outlays without assurances from regulators that the costs will be recoverable through approved electric rates, and unregulated companies will not make such outlays unless they believe their actions will be profitable.
3. Recommendations have no value unless they are implemented. Accordingly, the Joint Task Force emphasizes strongly that North American governments and industry should commit themselves to working together to put into effect the suite of improvements mapped out below. Success in this area will require particular attention to the mechanisms proposed for performance monitoring, accountability of senior management, and enforcement of compliance with standards.
4. The bulk power systems are among the most critical elements of our economic and social infrastructure. Although the August 14 blackout was not caused by malicious acts, a number of security-related actions are needed to enhance reliability.

The Joint Task Force Final Report contains 46 recommendations categorized as follows: institutional issues related to reliability; support and strengthening NERC's actions of February 10, 2004 (discussed in more detail below); physical and cyber security; and the Canadian nuclear power sector. The list of these recommendations is included in the attached appendix.

FERC, NERC, and MISO Responses

FERC

FERC responded to the August 13, 2003, outage by establishing a new 30-person reliability division to provide support to NERC's efforts and to implement FERC reliability initiatives.

Following the Joint Task Force's April 5, 2004 Final Report, FERC issued an order, dated April 14, 2004, clarifying its reliability policies and objectives with respect to the U.S. power grid. In its order, FERC issued the following directives:

1. That no new ISO or RTO will be allowed to begin operations until it has proven its reliability capabilities;
2. That it will consider the effect on reliability of all future decisions;
3. That it established a task force to report on potential funding mechanisms for NERC and the regional reliability councils to ensure independence from the utilities they monitor; and,
4. That it had initiated drafting of a memorandum of understanding to clarify its appropriate role in NERC oversight and the respective reliability responsibilities of FERC and NERC.

FERC also ordered all transmission providers in the lower 48 states to report on their vegetation management practices, recognizing that failure to maintain adequate vegetation clearances from transmission lines was one of the primary causes of the August 14, 2003, blackout. The reporting mandate follows FERC's release in March of a consultant's report on utility vegetation management, including recommendations on best management practices. In requiring these reports, FERC seeks to minimize the possibility that poor vegetation management practices will be a contributing cause of another regional blackout. Using the reported information, FERC intends to work with the state regulatory commissions to develop appropriate and effective ways to regulate transmission line vegetation management.

Further, FERC emphasized that it supports efforts to make NERC's reliability standards clearer and more enforceable. It also acknowledges there needs to be flexibility to address regional needs but that any regional variations should be consistent with and no less stringent than the NERC standards.

NERC

In cooperation and coordination with the Joint Task Force's investigation, NERC conducted its own investigation and on February 10, 2004, the NERC Board of trustees issued a report of its investigation and directed implementation of the recommended actions summarized as follows:

1. Require FE, MISO and PJM to correct the direct causes of the August 2003 blackout;
2. Strengthen the NERC compliance enforcement program;
3. Initiate control area and reliability coordinator reliability readiness audits;
4. Evaluate vegetation management procedures and results;
5. Establish a program to track implementation of recommendations;

6. Improve operator and reliability coordinator training;
7. Evaluate reactive power and voltage control practices;
8. Improve system protection to slow or limit the spread of future cascading outages;
9. Clarify reliability coordinator and control area functions, responsibilities, capabilities and authorities;
10. Establish guidelines for real-time operating tools;
11. Evaluate lessons learned during system restoration;
12. Install additional time-synchronized recording devices as needed;
13. Reevaluate system design, planning and operating criteria;
14. Improve system modeling data and data exchange practices.

NERC recognizes that the actions being taken to improve grid reliability have implications for electricity markets and market participants. Accordingly, NERC has directed its Market committee to help with the implementation of the above-stated actions and to work with the North American Energy Standards Board (NAESB)[7] on any necessary business practices.

By April 16, 2004, shortly after release of the Joint Task Force's Final Report, NERC reported that it had made substantial progress toward its February 10, 2004, action items. Milestones NERC has accomplished include, among others:

- Completed eleven on-site audits of control areas and reliability coordinators including FE, MISO, and PJM;
- Reviewed detailed plans from FE, MISO, and PJM for correcting the direct causes of the blackout;
- Approved guidelines for reporting and disclosure of violations of its reliability standards;
- Initiated implementation of its plan to accelerate adoption of new measurable reliability standards;
- Formed teams of technical experts to evaluate voltage control and reactive power practices, improve grid protection (relay) systems, improve operator training, improve system modeling data, and reevaluate system design, planning and operating criteria.

NERC continues to pursue completion of its February 10, 2004, action items and to work in coordination and cooperation with FERC to accomplish the recommendations of the Joint Task Force.

MISO

MISO, whose oversight responsibilities include the Wisconsin transmission system, has made significant improvements toward ensuring grid reliability in its area since the August 2003 blackout, and progress toward completing NERC's February 10, 2004, recommendations. On March 9, 2004, it released its reliability plan for completion of NERC's February 10, 2004, recommendations. On March 24, 2004, the NERC Operating Committee approved MISO's Reliability Plan.

[7] The NAESB serves as an independent industry forum for the development and promotion of standards which will lead to a seamless marketplace for wholesale and retail natural gas and electricity, as recognized by its customers, business community, participants, and regulatory entities.

Reliability enhancements that MISO has implemented subsequent to the blackout include:

- Full operation as of December 31, 2003, of its State Estimator, a comprehensive model of its transmission network, which monitors and measures on a real time basis the status of all transmission lines and generating plants in the region. This provides control room operators with comprehensive information on the condition of the grid, potential problems as they arise, and the ability to take necessary action to maintain reliability;
- Implementation of control room visualization tools covering greater detail and a larger geographic area providing real time values of megawatt and reactive power levels, voltage profiles and outage indications;
- Substantially upgraded alarming systems with improved identification of the significance of alarms;
- Improved communications and information sharing with PJM and other neighboring reliability organizations;
- Increased training including improvements and additions to training organization and staffing levels, and development of improved training plans and curriculum. All MISO Reliability Coordinators have undergone further training designed to provide them with the information needed to identify and manage abnormal operating conditions.

MISO continues to work toward completion of NERC's February 10, 2004, corrective actions in accordance with its Reliability Plan. By June 30, 2004, it is scheduled to implement a number of additional actions including, among others:

- Implementation of the first phase of the voltage and reactive power management plan;
- Collection of information as to its members' load shedding ability;
- Reduction of its contingency analysis run time to less than five minutes;
- Improvement of its multiple contingency analysis to comply with NERC standard;
- Establishment of a process to review and document Reliability Coordinator directives issued to control areas.

Wisconsin System Response and Current Status

As indicated in the Commission's Interim Report, the Wisconsin generation and transmission system withstood the August 14, 2003, blackout with only minor affects. A temporary increase in system frequency occurred system-wide at the time of the event. Minor voltage level variations also occurred. The one generating unit that tripped off line at that time, Edgewater Unit 4 in Sheboygan, experienced higher than normal furnace back-pressure due to ash buildup on the air heater. This operational problem has since been addressed. No loss of customer service occurred as a result of the blackout.

Wisconsin electric utilities, including the retail service providers as well as American Transmission Company (ATC), continue to focus on the need to improve system reliability. They maintain close coordination under MISO's oversight to monitor and control the operation of the electric grid in Wisconsin and have expressed strong support for the recommendations in the Joint Task Force's Final Report.

Generation

Under a Commission requirement, Wisconsin electric utilities must have generating capacity, either owned or under their control, to be able to supply the projected system peak demand plus a planning reserve margin of 18 percent.

Wisconsin utilities have sufficient generating capacity to meet that requirement for 2004 and have confirmed capacity at this time to maintain a planning reserve margin of over 15 percent for 2005, decreasing to about 9 percent for 2010. It is normal to complete commitments for the remaining reserve margin requirements closer to the year of need through a combination of new generation construction and new contracts.

The Commission has approved about 2,000 MW of new generation that is currently under construction, including 600 MW at Beloit and 50 MW at Kaukauna, expected to be on line before this summer. The Commission has also approved an additional 2,500 MW of generation not yet under construction but expected to be in service by 2008 to 2010. Further, another 1,030 MW of proposed generation is pending Commission approval. This additional generation capacity will serve to improve system reliability in that it will provide greater ability within the state to withstand unexpected outages of generating plants and transmission lines.

Transmission

The Wisconsin electric transmission system continues to be highly constrained and only marginally adequate as to its ability to transport power into and within the state. The Commission recognizes the need to increase the import capability into Wisconsin and, in 2003, reauthorized construction of the 210-mile Arrowhead to Weston 345 kV transmission line in northwestern Wisconsin. This project is expected to be completed in 2008.

The Commission has also recently approved several transmission line projects proposed by ATC to interconnect new generation to the grid and to improve the capacity and reliability of the transmission grid in localized areas throughout Wisconsin. Further, ATC’s long-range plans call for about $2.8 billion in capital expenditures over the next 10 years to address existing limitations and expected load growth within its footprint, and to improve transmission system transfer capability and access for importing power from neighboring activities and accommodating transactions between utilities. Many of the projects proposed by ATC will serve to improve system reliability.

A primary factor in the August 2003 blackout was determined to be inadequate tree trimming on FE’s transmission system. In Wisconsin, electric utilities are required under Wis. Admin. Code ch. PSC 114 to comply with the line clearance standards in the National Electric Safety Code. Further, they are required under Wis. Admin. Code ch. PSC 113 to conduct inspections of their transmission and distribution lines, and related rights-of-way, every three to eight years to identify natural hazards including inadequate tree clearances. (In the case of higher voltage transmission lines, the typical practice is to make visual inspections every year.) Upon identifying a potential hazard, utilities are required to take action to eliminate the hazard.

Utilities are required to file reports annually with the Commission indicating reliability performance results, and actions taken or to be taken to remedy any conditions responsible for unacceptable performance.

Utilities are also required to file preventative maintenance plans covering appropriate inspection, maintenance, and replacement cycles for generation, distribution, and transmission facilities. Every two years, utilities are required to file a report showing compliance with their preventative maintenance plans.

Ongoing Reliability Issues

The Commission supports the findings and recommendations of the Joint Task Force's Final Report, particularly the need for enforceable reliability standards at the federal level. Although the August 2003 blackout had only minor affects on the Wisconsin electric system, there are no guarantees that a similar outage could not happen in Wisconsin. Utilities in Wisconsin recognize that possibility and are moving in the right direction to improve the system's ability to operate reliably and to minimize the possibility of large-scale outages.

At this time, the Commission sees no need for a separate proceeding to address Wisconsin electric utility efforts in response to the Joint Task Force's Final Report, and FERC's and NERC's directives. Wisconsin utilities are supportive of those actions and appear to be making good progress toward meeting their obligations in that regard. The Commission will continue to oversee the actions of the Wisconsin utilities to ensure they work in cooperation with MISO to aggressively pursue the implementation of those recommendations and directives.

The Commission continues to be concerned about MISO's December 2004 scheduled implementation of a market-based transmission pricing plan within the MISO footprint. In comments filed with FERC earlier this month, the Commission raised serious concerns that MISO's market pricing plan was not ready for implementation and that it presented significant reliability and economic risks for Wisconsin. The Commission will continue to address its concerns with MISO and FERC to ensure that Wisconsin consumers are held harmless from these risks.

Increased reliability will not occur quickly nor without cost. Reliability will continue to be a primary consideration in the Commission's regulatory decisions. In the short term, the Commission will be addressing reliability in the context of proposed generation and transmission projects on a case by case basis. As indicated above, two proposed generation projects and several transmission projects are pending at this time and many more transmission projects are expected over the next several years. At least in part to recognize the importance of expeditious review of construction applications in the interest of reliability, 2003 Wis. Act 89 was enacted to streamline the Commission's review process in coordination with the Department of Natural Resources permitting processes. Some of the benefits of Act 89 have already been achieved; more are pending.

For the longer term, the Commission will continue to address the energy needs of Wisconsin in the context of the biennial Strategic Energy Assessment (SEA). A draft SEA was issued in April

2004. Public informational meetings are in progress and a public hearing is scheduled for June 2004. The Commission will be issuing a final SEA later this year. The current SEA will provide an outlook evaluating the adequacy and reliability of Wisconsin's current and future electrical supply through 2010. Longer term reliability issues identified through the SEA analyses will be addressed appropriately.

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Appendix

August 14, 2003, Lake Erie Loop Cascading Electric System Outage

Overview of Joint Task Force Recommendations

Group I. Institutional Issues Related to Reliability

1. Make reliability standards mandatory and enforceable, with penalties for noncompliance.
2. Develop a regulator-approved funding mechanism for NERC and the regional reliability councils, to ensure their independence from the parties they oversee.
3. Strengthen the institutional framework for reliability management in North America.
4. Clarify that prudent expenditures and investments for bulk system reliability (including investments in new technologies) will be recoverable through transmission rates.
5. Track implementation of recommended actions to improve reliability.
6. FERC should not approve the operation of new RTOs or ISOs until they have met minimum functional requirements.
7. Require any entity operating as part of the bulk power system to be a member of a regional reliability council if it operates within the council's footprint.
8. Shield operators who initiate load shedding pursuant to approved guidelines from liability or retaliation.
9. Integrate a "reliability impact" consideration into the regulatory decision-making process.
10. Establish an independent source of reliability performance information.
11. Establish requirements for collection and reporting of data needed for post-blackout analyses.
12. Commission an independent study of the relationships among industry restructuring, competition, and reliability.
13. DOE should expand its research programs on reliability-related tools and technologies.
14. Establish a standing framework for the conduct of future blackout and disturbance investigations.

Group II. Support and Strengthen NERC's Actions of February 10, 2004

15. Correct the direct causes of the August 14, 2003 blackout.
16. Establish enforceable standards for maintenance of electrical clearances in right-of-way areas.
17. Strengthen the NERC Compliance Enforcement Program.
18. Support and strengthen NERC's Reliability Readiness Audit Program.
19. Improve near-term and long-term training and certification requirements for operators, reliability coordinators, and operator support staff.
20. Establish clear definitions for *normal*, *alert* and *emergency* operational system conditions. Clarify roles, responsibilities, and authorities of reliability coordinators and control areas under each condition.
21. Make more effective and wider use of system protection measures.
22. Evaluate and adopt better real-time tools for operators and reliability coordinators.
23. Strengthen reactive power and voltage control practices in all NERC regions.
24. Improve quality of system modeling data and data exchange practices.
25. NERC should reevaluate its existing reliability standards development process and accelerate

the adoption of enforceable standards.

26. Tighten communications protocols, especially for communications during alerts and emergencies. Upgrade communication system hardware where appropriate.
27. Develop enforceable standards for transmission line ratings.
28. Require use of time-synchronized data recorders.
29. Evaluate and disseminate lessons learned during system restoration.
30. Clarify criteria for identification of operationally critical facilities, and improve dissemination of updated information on unplanned outages.
31. Clarify that the transmission loading relief (TLR) process should not be used in situations involving an actual violation of an Operating Security Limit. Streamline the TLR process.

Group III. Physical and Cyber Security of North American Bulk Power Systems

32. Implement NERC IT standards.
33. Develop and deploy IT management procedures.
34. Develop corporate-level IT security governance and strategies.
35. Implement controls to manage system health, network monitoring, and incident management.
36. Initiate U.S.-Canada risk management study.
37. Improve IT forensic and diagnostic capabilities.
38. Assess IT risk and vulnerability at scheduled intervals.
39. Develop capability to detect wireless and remote wireline intrusion and surveillance.
40. Control access to operationally sensitive equipment.
41. NERC should provide guidance on employee background checks.
42. Confirm NERC ES-ISAC as the central point for sharing security information and analysis.
43. Establish clear authority for physical and cyber security.
44. Develop procedures to prevent or mitigate inappropriate disclosure of information.

Group IV. Canadian Nuclear Power Sector

45. The Task Force recommends that the Canadian Nuclear Safety Commission request Ontario Power Generation and Bruce Power to review operating procedures and operator training associated with the use of adjuster rods.
46. The Task Force recommends that the Canadian Nuclear Safety Commission purchase and install backup generation equipment.