Date	Rec Type	Recommendations/ Comments	Name	Organization
1/9/2004	Reliability Standards	Future reliability standards must strike a balance between detailed, rigid requirements, which provide little or no latitude for deviation, and standards, which are objective-based and allow for innovation and invention to achieve intended goals. Each standard should identify its importance on the BPS reliability in terms of the potential short-term (operating time horizon) vs. long-term (planning time horizon) impacts of non-compliance.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Reliability Standards	Core Reliability Standards: comprising a small number of technical standards designed to enable the BPS to withstand and recover from unexpected contingencies. Core Reliability Standards would be prescriptive, include metrics for measuring and reporting accomplishment, and be subject to compliance monitoring. Examples include requirements to observe (N-1) criteria, maintain Operating Reserve requirements, identify and respond to Operating System Limit Violations, etc. The development of these standards need not follow the existing NERC voting process. Rather, they should be promulgated following consultation with industry stakeholders.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	System Operations	Good Utility Practices: comprising processes or objective-based standards designed to prevent the development of adverse conditions that increase the risk of widespread disturbances. These standards have little or no direct, real time impact on the BPS reliability and should be developed through the industry stakeholder process. Examples include vegetation management and the nature, scope and reporting of system planning studies (e.g. PV and QV analysis to determine post-contingency voltages and reactive support requirements; assessment of extreme contingencies to test the robustness of interconnected system, etc.).	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Reliability Standards	The size and number of reliability coordinators and/or control areas are not the factors in determining their effectiveness. However, a single operating entity (“herein referred to the reliability coordinator (RC)”) should be responsible to coordinate all real-time reliability functions over a logical, contiguous, portion of the Bulk Power System. Jurisdictional boundaries should be established based upon electrical interfaces, size and regulatory authority. Transmission owners, generators and customers within prescribed boundaries should be obligated to follow the direction of the reliability authority. Membership requirements regarding reliability issues should be prescribed and non-negotiable.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Communication	The Interim report of the August 14 blackout revealed difficulties in equipment and operator response. These difficulties existed despite the fact that entities were NERC certified. This suggests substantial changes in the current Control Center and Operator certification process.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Reliability Standards	The RC should be licensed by a regulatory agency, through a thorough and comprehensive certification process, which addresses the organization’s accountability and responsibility, its physical facilities, processes and procedures. In particular, control room equipment and operations should be thoroughly examined to ensure that adequate system(s) and current technology are available to its operators.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/9/2004	Training	Operating personnel employed by the reliability authority should be certified based on experience, knowledge, training and test results involving power system simulators. Certification should be based on independent audits conducted without prejudice by competent personnel who are neither employees of any reliability authority nor affiliated with companies that provide consulting services to reliability authorities.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Structure of the Market	“Wide-area” overview should be transferred between RCs. This should also include alarms indicating violations of Core Electric Reliability Standards. Notifications should also be send to regulatory and other agencies/authorities to ensure that the basic reliability safeguards are in place.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Emergency plans	Define “emergency” and the nature of associated critical contingencies, along with different levels of emergency alerts to assist operators in their decision making process. This could be based on a combination of factors such as NERC standards, failure to restore operations within OSL, significant risks of multiple contingencies, failure of equipment, Health and Safety, Environment etc.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Standards development	Develop comprehensive requirements/specifications including benchmarking of control centers to establish minimum requirements for effective and reliable control center infrastructures, systems and minimum tools to address emergency response, operator training and certification related issues.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Structure of the Market	Establish necessary authority which operators of the system (and the reliability coordinators), must have to act in a timely manner during an emergency. As a minimum, operators should be empowered and authorized to promptly load shed to avoid cascading outages, recognizing that preventive actions may sometimes adversely impact electricity market trading. Any entity should be able to declare emergency and it should remain in place until the declaring entity is satisfied that it is acceptable to remove it.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Standards development	Require that adequate and competent human resources be available to assess a full range of credible emergencies to respond to rapidly escalating system emergencies. Real time notification of key contingencies associated with Core Reliability Standards and their anticipate impacts should be communicated among operating personnel (and reliability coordinators).	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Training	Require joint workshops/training of operators from other areas and reliability coordinators. Require that operators responsible for the reliability of the interconnected Bulk Electric System should not be participating in the market functions to avoid distraction and pressures of market functions and commercial operations (Gx dispatch, bidding, FTRs etc).	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Technical operating procedures	Specifically, three important issues for transmission planning need immediate attention: What sources and processes will provide transmission planners with reliable information for “integrated resource planning” on the locations, types, capacities, and in-service dates of new transmission and generation? What entity will be responsible for developing projections of future load growth? What control actions/authority is available to implement the recommendations stemming from integrated planning studies?	Ajay Garg, Mike Penstone	Hydro One Networks Inc.

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/9/2004	VAR/Grid Intergration	The improvement to current modeling process is an ongoing process. Although existing processes for developing system models used for study and analysis are sufficiently accurate, the analysis and assessment process among regions, reliability coordinators and control areas, and member systems vary considerably. For examples, P-V and Q-V analysis coordinated with across system boundary members should be done to determine reactive power requirements under to ensure that a) the interconnected system is not operating at the risk of voltage stability; b) to determine adequate voltage support on all parts of the system, including static and dynamic reactive reserves for system stability.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Investment	Determination of “transmission lines and facilities ratings” should be the sole responsibility of the facility owner. Facility owners should communicate the rating to the reliability authority for intra and inter regional coordination by ensuring that the most limiting element in series establishes the interface rating. There is no reason why this process can not be appropriately applied to establish dynamic ratings.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Vegetation management	There were too many coincident failure of processes, practices, competency, human errors, non-compliance with reliability standards along with operating policies that lead to the August 14 outage. 1)The maintenance issues such as vegetation management and right of way should be the responsibility of the local regulators as part of transmission and distribution license. 2)Industry stakeholders should develop maintenance-related guidelines to establish Good Utility Practices. 3)Private land owners of the right-of-ways should not be allowed to delay Vegetation Management through legal processes.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Investment	We believe that future solutions must not undermine the existing benefits of strongly integrated international grid. New technologies to enhance reliability must not sacrifice transmission capability or operating flexibility needed to enable electricity markets to function and prosper.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	VAR	We recommended that the industry consider migrating to the use of current based differential schemes, where possible. Load current does not affect these types of protections, operating on the basis of Kirchhoff’s first law. Theoretically, currents from both ends of a two terminal line subtract to zero for external line faults, and add up to operate for internal line faults. Current based differential pilot schemes rely heavily on the use of telecommunications. The remote current information is needed for local comparison, to make a trip/no trip decision. Present day’s high- speed reliable digital telecommunications with alternate paths, now provide a reliable communication mechanism to facilitate this migration.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/9/2004	Grid Intergration	The industry, where feasible, should be installing load-independent relays, which are proven to be stable under frequency deviation conditions, at critical locations. Moreover, alarms should be generated when loads approach any of the protective relay characteristics.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	System Operations	The under-frequency protection is designed to detect a decreasing frequency in the power system and to minimize the effect of a major disturbance, and facilitate restoration. The current practices for load-shedding schemes are to balance, within reason, the unbalance between load and generation of an “area.” This coordination and effective load shedding becomes complex for cascading outages such as the one on August 14th and requires greater coordination among Areas and Regions.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	System Operations	Under voltage load shedding can be used to rapidly change the voltage profile and arrest an impending voltage collapse. However, there is a possibility of unnecessary load shedding. Frequency is a much better parameter than voltage, as a system indicator. Voltage deviations can be caused by many normal contingencies where load shedding is not warranted. It should be considered only if other measures that have been applied have failed to achieve the desired result e.g. when adding reactive sources is considered not effective, etc.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Investment	Phase measurement technology permits microsecond time-stamped sampling of electrical parameters such as power, voltage, etc. This technology in concert with the use of high-speed digital communications allows real time monitoring of the power system and control within the time frame of a power system cycle (17ms). The use of this technology monitoring all Area tie lines can provide real-time net power flows and can initiate reactive actions as required while experiencing a disturbance. In comparison, SCADA systems and loading shedding schemes react seconds after a disturbance, not during. This technology can also be applied for Inter-Area and regional applications. Protection IED adoptive capabilities can be used to momentary block distance zone 2 operations that can be susceptible to load.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Technical operating procedures	Provide time synchronization for all protection IEDs, SERs, DFRs RTUs, DSRs, and other devices required for event analysis. Time synchronization should be to a standard time source such as GPS. Provide facilities and processes (automation, and the integration) for the efficient and timely collection of event data. Encourage wider use of Disturbance System Recorders, or otherwise knowing as “Swing Recorders” through established practices. They should be installed at major stations and the information should be made available to Areas, Inter-Areas, and Regions.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	VAR	Consideration should be given to contingency-based load shedding, with trip signals directed to specific areas based on a pre-defined or dynamically determined islanding strategy.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.
1/9/2004	Editorial comment	A new vision and strategy are required to maintain the reliability of the North American bulk power system. The strategy must consider and integrate all factors influencing reliability, balance the need for regulation and innovation, and avoid unnecessary or ill-conceived arbitrary actions.	Ajay Garg, Mike Penstone	Hydro One Networks Inc.

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/9/2003	Training	I am bringing attention to a *Megawatt Daily* article, criticizing the Interim Report for dismissing or downplaying some issues, suggesting that FERC and NERC should shoulder some blame for approving FirstEnergy's training of operators and MISO's operations.	Alex Galatic	personal-not views of his company (Strategic Energy) (should we say his company name?)
12/9/2003	VAR	*Megawatt Daily's* article suggests that the Interim Report "incorrectly dismisses as unimportant heavy power flows to Canada through Ohio and low voltage support to accommodate those flows." I think it is clear from the information provided in the report that the power flows to Canada were not the cause, and neither was the voltage support in Ohio. Ohio never was reported to have a problem with adequate voltage support when I was a Bulk Power Supply engineer. If Ohio suffers from low voltage support now, then the latest ECAR summer reliability assessment should point this out.	Alex Galatic	personal-not views of his company
12/4/2003	Other	It is remarkable that these two blackouts were predictable a long time before they actually occurred. My research, chronological and experimental, recorded by two machines designed by myself, allow me to categorize the cases in this report in two categories: a)"at risk", these are some days during the calendar year, August 14th; b)“no risk" meaning the rest of the days of the calendar year. During this period, power breakdown may still happen, caused by regular defects on the network or by a bad management. This work may provide a few minutes notice of likelihood of blackout and I offer it to the Administration, if they are interested.	Alexandre Laugier	Personal comment
1/16/2004	Editorial comment	FirstEnergy believes that a wide-ranging analysis of regional grid effects on August 14, 2003 is the most effective way of creating a comprehensive list of lessons learned for the benefit of all stakeholders at an efficient cost.	Anthony J. Alexander	FirstEnergy
1/16/2004	Reliability Standards	If Task Force recommendations on grid viability, grid state and grid management, including reactive power and parallel flows, consistent with the recent NERC operating guidelines, address these contributory factors, then it will go a long way toward improving reliability under the current operating conditions. It would also minimize much of the inherent problems of the Interim Report that impact on future reliability.	Anthony J. Alexander	FirstEnergy
1/16/2004	Reliability Standards	The goal for all stakeholders should be to ensure reliable service to native load customers while supporting growing market transactions.	Anthony J. Alexander	FirstEnergy
1/16/2004	Editorial comment	As an overall observation, we believe that the Interim Report should have contained a more detailed explanation of the methodologies and analyses used to reach the underlying conclusions. We also note that in some cases, the reliance on modeling and theories rather than actual data resulted in significant errors and omissions, generally, and specifically respecting events and actions in FirstEnergy’s control area, including our compliance with NERC Operating Policies, our energy management system, our vegetation management practices, and reactive power flows in and around our system.	Anthony J. Alexander	FirstEnergy

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/16/2004	Editorial comment	One important example is the discussion on page 19 of the Interim Report; stating, “based on “modeling,” that FirstEnergy was a net importer of VARs at 15:00 EDT.” Actual data, which we supplied to the Task Force, demonstrates that FirstEnergy was a net exporter of VARs at that time.	Anthony J. Alexander	FirstEnergy
1/16/2004	Editorial comment	Because, the outage is the subject of various legal proceedings, involving FirstEnergy and others, the ability of affected entities to comment in detail at this time is limited. Likewise, entities are limited from commenting because full information is not available to them. But irrespective of these limitations, as we announced following the publication of the Interim Report, FirstEnergy is much more interested in moving forward by helping with the development and implementation of the kinds of recommendations that will truly minimize the risk of future outages of this magnitude.	Anthony J. Alexander	FirstEnergy
1/16/2004	Investment	In developing recommendations in Phase II of the investigation, it is particularly interesting to note Section 6 of the Interim Report, which states that this outage was essentially similar to 7 other major outages between 1965 and 1999. If this is true, then it illustrates, dramatically, that investigators must look hard for the complete answers, given the manner in which the grid is now used.	Anthony J. Alexander	FirstEnergy
1/16/2004	Grid integration	Competitive markets have pushed the grid beyond its design, while, at the same time, as the Interim Report notes at page 67, virtually no major transmission projects have been undertaken in North America. The margins that were built into what once were local grid systems to accommodate changes in local load patterns and reliability have been reduced to allow power transactions over long distances to areas with inadequate supplies of local generation.	Anthony J. Alexander	FirstEnergy
1/16/2004	Structure of market	At FirstEnergy, we believe that recommendations coming out of this investigation must recognize the emergence of competitive markets in recent years and address the ramifications of these new markets on the grid generally. This will require that all stakeholders re-examine the practices, procedures, and tools that have served the industry well for years, but that may no longer be adequate in today’s environment.	Anthony J. Alexander	FirstEnergy
1/16/2004	Communication/ Editorial comment	This re-examination must include communications with and between the reliability coordinator and neighboring utilities. A number of new technologies are emerging that can improve communications, and we need to ensure that such technologies are developed and deployed fully. This point highlights a shortcoming of the Interim Report, which did not note that a review of the transcripts of all operators, including those at AEP, PJM and MISO, reveal significant gaps and problems in how the conditions taking place on the grid were being communicated and addressed between and among the various entities.	Anthony J. Alexander	FirstEnergy
1/16/2004	Analysis	This re-examination must include an analysis by the appropriate parties and agencies of the loop flows around Lake Erie that place a significant burden on the FirstEnergy system.	Anthony J. Alexander	FirstEnergy

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/16/2004	Vegetation management/ training	This re-examination must include appropriate industry practices relating to tree trimming, control room operator training und certification, and control center computer systems. In this regard, while the Interim Report of critical of FirstEnergy's vegetation management; the Report does note that FirstEnergy tree trimming practices are aligned with current industry standards. The report does not however take note of the fact that trees in other control areas tripped transmission lines on August 14, even before any events on FirstEnergy's system, with the exception of the Stuart-Atlanta line owned by Dayton Power & Light. With respect to operator training and certification, the interim Report does not mention that all of FirstEnergy's transmission control room operators are NERC-certified.	Anthony J. Alexander	FirstEnergy
1/16/2004	Standards development	Simplify grid coordination and management, in part by requiring that all electrically significant systems be in the same regional transmission organization (RTO), operating under common reliability authorities, or under some other type of common control.	Anthony J. Alexander	FirstEnergy
1/16/2004	Reliability Standards	Expand the wide-area observability and management requirements for reliability authorities and RTOs that include monitoring and alerting control area operators of regional events and conditions that may impact those control areas. This requires an overall conceptual review of the transmission system as a whole, especially as regional conditions transcend individual control area, RTO and reliability authority boundaries.	Anthony J. Alexander	FirstEnergy
1/16/2004	Structure of market	Obligate all generators and market entities using the interconnected transmission grid to provide for the support of the grid through reactive power, voltage control and any other action needed to assure reliability. Reliability must come ahead of market subsidies, such as occur when independent generators are not required to support the grid.	Anthony J. Alexander	FirstEnergy
1/16/2004	Structure of market	Require better monitoring and control of power flows, particularly loop and unscheduled flows. This ultimately requires that all market or wholesale transactions are rendered and managed based on actual flow conditions, rather than scheduled contract paths. It further involves development of improved tools for closer to real-time management of transactions.	Anthony J. Alexander	FirstEnergy
1/16/2004	Reliability Standards	Require expanded regional coordination of reactive supplies, including static and dynamic reactive margins, and effective regional coordination of voltage schedules, including clear authority by reliability authorities and RTOs to direct such reliability actions.	Anthony J. Alexander	FirstEnergy
1/16/2004	Grid integration	Require that transmission system margins that are used by new generators be restored and paid for by such generators, and not be a burden on local utilities or customers.	Anthony J. Alexander	FirstEnergy
1/16/2004	Reliability Standards	Ensure reliability and service over market transaction opportunities by requiring that transmission capacity first be reserved for local customers, with an adequate margin for emergencies and contingencies: i.e., a local service priority, before capacity can be used to support long—distance competitive power transactions.	Anthony J. Alexander	FirstEnergy

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/16/2004	Reliability Standards	Require that mandatory reliability standards applicable to all market participants be put in place with adequate backup arrangements to recognize that equipment, computers, lines and power plants will fail for a variety of reasons.	Anthony J. Alexander	FirstEnergy
1/16/2004	Training	Require clarification of NERC and regional reliability organizations' operating policies and procedures, including those involving the functions, responsibilities and authority of reliability authorities, RTOs and control areas, and ensuring the development of new reliability standards for all such regional and market entities.	Anthony J. Alexander	FirstEnergy
1/16/2004	Structure of market	Require that "control area only" generation satisfy the reliability requirements of the RTO. Require that planning and Improvements to the grid be coordinated, identified, and acted upon in a timely manner. Require that cost recovery rules be changed to allow more timely recovery (during construction and licensing), reasonable returns (higher returns with shorter lives), and automatic pass—through, so as to encourage and compensate for reliability improvements to the grid.	Anthony J. Alexander	FirstEnergy
11/24/2003	Edit	People are interpreting "remote terminals" as "remote terminal units (RTUs)." I doubt that's correct, but clarification and/or a clean-up is in order for the terms, "remote control consoles, remote location consoles, remote EMS terminals, remote control terminals, and remote terminals." Also, once standard terminology is decided upon, an entry should be added to the glossary and to the EMS fact box on page 26 of the Interim Report.	Armin Boschmann	Manitoba Hydro
12/10/2003	Reliability Standards	This report provides more powerful evidence that we need a better long-term national energy policy if we are to ensure the reliability of our grid that consumers deserve. Governor McGreevey has advocated for three steps that would address many of the problems cited in this report: mandatory transmission grid reliability standards; mandatory participation by all utilities in a regional transmission organization (RTO),and increased federal funding for grid investment, with a particular focus on smart grid technologies that will eliminate much of the	C. Dortch Wright on behalf of NJ	On Behalf of New Jersey Governor J.E. McGreevey
12/10/2003	Legislation	It is our hope that Congressional leaders will pursue a separate bill on grid reliability that will avoid the pitfalls of the omnibus bill. This separate reliability bill should include the mandatory reliability standards in the latest omnibus bill, but also increase smart grid investment and	C. Dortch Wright on behalf of NJ	On Behalf of New Jersey Governor J.E. McGreevey
12/11/2003	Standards Development	IT plays a major issue in two of 3 main causes of the blackout cited in the report, including inadequate situational awareness and inadequate reliability. The report does not address these	Carl Hauser	School of Electrical Engineering and
12/11/2003	Systems Operations	The Interim Report notes (p. 30) that beginning between 14:20 and 14:25 EDT FE's remote control terminals in remote substations began failing due to "queuing" and "overloading the terminals' buffers". This is a serious design or implementation flaw in the alarm system	Carl Hauser	School of Electrical Engineering and Computer Science
12/11/2003	System Operations	At 14:41 EDT the FirstEnergy EMS primary server failed for reasons that are speculated to be either stalling of the alarm application or queuing backlog at the remote terminals (p. 30).	Carl Hauser	School of Electrical Engineering and
12/11/2003	System Operations	Failure of the primary and backup EMS servers also took out the AGC function, the strip chart function and ACE function as well as slowing the operators' screen update rate to "a crawl". The design of backup functionality in the system again appears to be inadequate.	Carl Hauser	School of Electrical Engineering and Computer Science

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/11/2003	Investment	Post-outage it was determined that the “only available course of action to correct the alarm problem was a ‘cold reboot’ of FE’s overall XA21 system.” (p.32) At 15:42 control room operators had decided not to allow IT personnel to perform a cold reboot because they “considered power system conditions precarious, were concerned about the length of time that the reboot might take to complete, and understood that a cold boot would leave them with even less EMS support until it was completed.” (p. 32) Again one questions the design of the EMS: it fails at a time when the power system state is “precarious” and the *only* solution to such a failure is a cold reboot which will render it even less available over an extended period of time.	Carl Hauser	School of Electrical Engineering and Computer Science Washington State University
12/11/2003	Training	When the SE does not reach a solution, the system engineer must diagnose the cause – a time-consuming activity (apparently, diagnosing the Stuart-Atlanta line outage took about 20 minutes (p. 27)). The question here is whether the combined automated and manual system constitutes an adequate analysis framework for reliable operation. The state estimator normally runs every 5 minutes. If it fails, manual diagnosis taking (based on the one data point) 20 minutes is required. Does this give the reliability coordinator adequate time to respond to a contingency?	Carl Hauser	School of Electrical Engineering and Computer Science Washington State University
12/11/2003	Editorial Comment	The INTERIM REPORT does not mention the Interchange Distribution Calculator (IDC) even in the system overview section, yet the MISO phone transcripts indicate that operators at several utilities and MISO were having difficulty performing updates to it on Aug. 14, both earlier in the day and after the outage.	Carl Hauser	School of Electrical Engineering and Computer Science Washington State University
12/11/2003	Editorial Comment	The conversations and published descriptions raise two concerns about the IDC. First, its slow performance was apparently a distraction to the operators during early stages of recovery from the outage. It became difficult to load line status and TLR information into the IDC.	Carl Hauser	School of Electrical Engineering and Computer Science Washington State University
12/11/2003	System Operations	The other concern relates to the IDC design. The operators in the phone transcripts and the description of the IDC interface refer to it as a “web page” and refer to “the internet” being “slow today”. (These conversations are post-outage and so would not be seen as causally related.) Later an operator says “we have no internet connection to access OATI [operator of the IDC]” (MISO 2003 08-14 CH20 Second RC 1722hrs.wav) It is not clear whether the “internet” referred to here is the public internet or a private network, however, there is nothing to discount the former interpretation. If that were the case, it would be a major concern for several reasons, including susceptibility due to power outages and overload due to internet virus and worm activity.	Carl Hauser	School of Electrical Engineering and Computer Science Washington State University

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/11/2003	System Operations / TECH	The IR details the failure of the alarm system at FirstEnergy and the unawareness of the failure by FirstEnergy personnel (pp. 28 ff). In summarizing the causes the IR concludes that the root causes were “FE lacked procedures to ensure that their operators were continually aware of the functional state of the critical monitoring tools” (p. 23, Group 1,C) and “FE lacked procedures to test effectively the functional state of these tools after repairs were made.” (p. 23 Group 1, D). What is missing here is any questioning or analysis of the design of these tools that allowed them to fail as they did.These observations from the IR strongly suggest that a line of inquiry is needed into the reliability characteristics first, of the EMS at FE, second of any other installations of the same product, and third of other EMS products in use in the North American power grid. The IR notes that the FE EMS is scheduled for replacement and was not the latest version available. These facts do not obviate the need to investigate the cause of the EMS failures.	Carl Hauser	School of Electrical Engineering and Computer Science Washington State University
12/11/2003	System Operations	The power grid increasingly relies on IT systems to operate more efficiently and in a more market-oriented fashion. The IR does not delve deeply enough into the IT domain to make	Carl Hauser	School of Electrical Engineering and
12/3/2003	Editorial Comment	As a representative of the Cuyahoga County Board of Commissioners, I served on a Community Advisory Panel created for Cleveland Electric Illuminating Co. (later First Energy). This panel was mandated as part of the Public Utilities Comm. order when the Perry nuclear plant was added to the rate base. The panel included representatives of the intervenors in the rate case, as well as some community representatives. First Energy eliminated this panel, with no consequences forthcoming from the Public Utilities Comm. The company was not happy with the panel because we raised many questions about its customer service. For example, we asked questions about the tree trimming program, a relevant issue in the blackout report, because we had concern about the company's service plan during a time of job and budget cuts. The majority of our panel saw real problems with the company's customer service and its communications with the public. Unfortunately, very little I have read about the company since the panel's demise has changed my view of First Energy.	Carolyn Milter	Cuyahoga County Board of Commissioners, Community Advisory Panel member created for Cleveland Electric Illuminating Co. (later First Energy)
12/1/2003	Edit	Page 6. In the vignette (sidebar) it’s more correct to say that reactive power can be transmitted over only relatively short distances during heavy load conditions.	Carson Taylor	Bonneville Power Administration (BPA)
12/1/2003	Edit	Page 18. A minimum acceptable voltage of 92 percent reduces the robustness and resilience of the power system. Can ANSI C84.1-1995 Range A minimum utilization voltages be met with 92 percent transmission voltage?	Carson Taylor	BPA
12/1/2003	Edit	Page 18, vignette on Independent Power Producers and Reactive Power. NERC Planning Standard III.C.S1 states: All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator. Automatic voltage control mode means that there is no follow-on reactive power or power factor control mode to undo automatic voltage regulator action. Such control contributed to the August 10, 1996 power failure.	Carson Taylor	BPA
12/1/2003	Technical Operating	A recommendation for the final report should be to prioritize control and protection improvements for both generation and transmission. Compared to transmission line additions,	Carson Taylor	BPA

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/1/2003	Safety Net	My recommendation for IPP generator control is that generators must be in automatic voltage control mode at all times, controlling the voltage at the point of interconnection according to the transmission company voltage schedule.	Carson Taylor	BPA
12/1/2003	Edit	Page 19, Eastlake Unit 5 trip (Figure 3.5). Since this is an important plant, upgraded control and protection appears desirable. The Eastlake control apparently is obsolete in two respects: control is tripped to manual and even worse (according to page 12 of the EPRI	Carson Taylor	BPA
12/1/2003	Edit	Page 20. More details should be provided on the power flow simulations. What other data had to be adjusted such as generator reactive power limits? For outage simulations, did some generators have to be modeled in reactive power or power factor control mode? See, for example, NERC Planning Standard II.B.S1 and II.B.M3.	Carson Taylor	BPA
12/1/2003	Edit	Page 33. For Figure 4.5 and subsequent charts, it would be good to describe the measurement characteristic. The charts appear to be continuous recordings, but they probably are from digital SCADA records with 2–4 second sample intervals.	Carson Taylor	BPA
12/1/2003	Edit	Page 40. Re "the 138-kV system collapsed." The word system is greatly overused. Because all parts of the power system (generation, transmission, subtransmission, distribution) must work together, it's best to reserve system for the entire power system. With restructured industry, system engineering is more important than ever.	Carson Taylor	BPA
12/1/2003	Edit	Page 43. More often than not, voltage-sensitive equipment goes off-line because of overly sensitive controls.	Carson Taylor	BPA
12/1/2003	Edit	Page 43, Figure 4.14. Some voltages may have been substantially lower than shown on the chart. At the blackout panel session at the IEEE Power Engineering Society Transmission and Distribution Conference and Exposition, the AEP panelist stated that voltage was approximately 80% just prior to the Canton Central–Cloverdale 138-kV line trip at 15:45:33. If voltages were that low (25 minutes before major cascading), under voltage load shedding certainly comes to mind as a solution. The presentation is publicly available at http://www.ieee.org/portal/index.jsp?pageID=pes_level1&path=pes/subpages/meetingsfolder/td_dallas2003&file=tdpanelsessions2003.xml&xsl=generic.xsl#System%20Blackout%20Roundtable.	Carson Taylor	BPA
12/1/2003	Edit	Page 44. It would be good to document the reasons for the 138-kV line trips (e.g., type of relay). Were there any short circuits? (Protective relays are installed to detect short circuits, not to operate on overload.)	Carson Taylor	BPA
12/1/2003	Edit	Page 49. With regard to the 531 generator unit trips, compliance with NERC Planning Standards should be documented. NERC Planning Standards III.C.S3, III.C.S4, and III.C.G3 were developed specifically to prevent unnecessary trips during breakups. Similar to nuclear plants, reasons for trips of other plants should be detailed. As far as grid interactions, all power plants should meet similar standards.	Carson Taylor	BPA
12/1/2003	Edit	Page 50, vignette on Impedance Relays. This is misleading. Impedance relays can—and should be—applied without zone 3 relays. NERC Planning Standards III.A.G17 states: "application of zone 3 relays with settings overly sensitive to overload or depressed voltage	Carson Taylor	BPA

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/1/2003	Edit	Page 55 and 56. I think "…due to apparent impedance faults (short circuits)" should be changed to "…due to impedance relay operations on overload and depressed voltage. "Were there really short circuits? Did zone 3 relays operate again?	Carson Taylor	BPA
12/1/2003	Edit	Page 57. What was the mechanism for the Branchburg–Ramapo 500-kV line trip? Zone 3 relays again, or Zone 1 or 2 operation because of swing?	Carson Taylor	BPA
12/1/2003	Edit	Page 59, vignette on Under-frequency Load-Shedding. In a large system, islanding is almost always required for underfrequency load shedding. Failure to shed enough load results in generator tripping and frequency/voltage collapse (blackout).	Carson Taylor	BPA
12/1/2003	Edit	Page 61. Some editing is desirable. For example, the impedance relays that operate are located near the electrical center (swing center). This is the location where zero voltage occurs during an unstable swing. It could be within a generator or generator step-up transformer. This is a form of "voltage collapse," but is angle rather than voltage instability.	Carson Taylor	BPA
12/1/2003	Edit	Page 63. "Voltage collapse" and related terms, are defined by the IEEE/CIGRE Joint Task Force on Stability Terms and Definitions [3,4]. Voltage instability is associated with load response/load restoration following outages. Some industrial (motor) load tripped because of the low voltages. Remaining voltage sensitive load may not have restored because of bulk power delivery on-load tap changing transformers reaching limits—allowing stable operation with depressed voltage (partial voltage collapse). Regarding "lines began to trip out automatically on protection from overloads, rather than from insufficient reactive power," depressed voltage (from insufficient reactive power), probably contributed to operation of impedance relays. Regarding "protection from overloads," I think most if not all protection was installed for short circuits, but operated for overload.	Carson Taylor	BPA

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/1/2003	Edit	Page 64. Compliance with NERC Planning Standards III.C.S3, IIIC.S4, III.C.M4, III.C.M5, IIIC.M6. III.C.M7, IIIC.M9, III.C.G3, IIIC.G.7, and IIIC.G10 is of interest.	Carson Taylor	BPA
12/1/2003	Edit	Page 67–70. The September 23, 2003 blackout in Sweden and Denmark might also be mentioned. The west coast blackouts are better described as California/Southwest blackouts, or western interconnection blackouts (i.e., Vancouver, Seattle, and Portland load centers were not affected).	Carson Taylor	BPA
12/1/2003	Edit	The descriptions of the July 2–3 and August 10, 1996 power failures could be improved. "June 24, 1998: Ontario and U.S. North Central Blackout" is misleading since major load centers in Ontario were not involved. The outage affected the Upper Midwest (mainly the Dakotas, Minnesota, Manitoba, Saskatchewan, western Wisconsin, and northwestern Ontario).	Carson Taylor	BPA
12/1/2003	Edit	Page 71. More details on reactive power derating because of high ambient temperatures should be provided. This is unusual since temperatures were not extreme. Generators controlled to a fixed power factor violate NERC Planning Standards III.C.S1. The last sentence on the page seems unrelated and out-of-place.	Carson Taylor	BPA
12/1/2003	Edit	Page 73. "Abnormal conditions" should be changed to "short circuits."	Carson Taylor	BPA
12/1/2003	Edit	Page 78. Overexcitation should not trip the generator. Overexcitation limiters should reduce field current to continuous capability, overriding voltage control. If the field current reduces below continuous rating because of improved system conditions, return to voltage control should be automatic; see NERC Planning Standard III.C.M6.	Carson Taylor	BPA

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/1/2003	Unclear	Page 80. Regarding Fermi 2, the excitation control and protection appear to be improperly designed. See NERC Planning Standard III.C.M6, etc. What is meant by "The turbine trip was likely the result of multiple generator field protective trips (overexcitation and loss of field)…"? A generator only trips once. Is the overexcitation limiter tripping to manual or reducing field current to continuous capability multiple times? Loss of field (loss of excitation) trips the generator.	Carson Taylor	BPA
12/1/2003	Edit	Page 83. Regarding Perry, out-of-step relays sense low apparent impedance—not ground faults.	Carson Taylor	BPA
12/10/2003	Reliability Standards	NPCC maintains that development of North American-wide reliability standards should represent a floor rather than a ceiling. More stringent regional criteria and rules that acknowledge unique regional needs make for a more robust overall system, especially when operations outside of normal system conditions are encountered. Additional regional reliability requirements provide for extra margin that adds flexibility when extraordinary events occur.	Charles J. Durkin	Northeast Power Coordinating Council (NPCC)
12/10/2003	Reliability Standards	NPCC supports current efforts to provide for enforceable reliability criteria industry-wide. NPCC's reliability criteria are mandatory under the *NPCC Membership Agreement* and enforceable through its Reliability Compliance and Enforcement Program. This program continues to demonstrate its effectiveness in ensuring that NPCC's membership meets the reliability requirements. The program focuses on those criteria and standards that have a direct impact on the reliability of the bulk power system. Compliance with reliability standards in NPCC is attained through a combination of non-monetary sanctions, including formal notification to state and provincial regulatory authorities, and well-designed markets. The NPCC program has clearly demonstrated the effectiveness of using non-monetary sanctions and market mechanisms to achieve reliability objectives.	Charles J. Durkin	NPCC
12/10/2003	Reliability Standards	The Interim Report clearly indicates that the NPCC Region was not the cause of the events, but was engulfed by an unprecedented power tsunami. In fact, the NPCC Region withstood, without advance warning, the initial power surge from the Midwest and remained stable, but was eventually overwhelmed by the cumulative effects of the large onrushing power flows, & severe frequency and load oscillations. These subsequent power swings islanded portions of the NPCC Region from the rest of the eastern interconnection. Our suggestions for improving the reliability of the electric system include: a)Each interconnected system must provide an adequate set of tools, resources & procedures necessary to operate the system according to its design & within conditions known to be reliable through analytic study; b) Each system must be capable of taking local action-to keep local problems from spreading. c)The events of August 14, '03 clearly demonstrate the need for mandatory reliability standards for the electric system, standards that define not only the reliability objective, but also the obligation to provide the capability to achieve that objective.	Charles J. Durkin	NPCC

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/4/2003	Investment	The August 14th, 2003 Blackout exposed serious weaknesses in the Nation’s IT Infrastructure that supports both control area operations and the coordination between regions and Authorities. Our company offers a way to independently consolidate contiguous control areas using a bottom up approach, built on proven technology that increases the level of detail needed for real time communications. This process removes some of the coordination required today. http://electricity.doe.gov//govforums/documents/comments/120403_0001.pdf	Chris Booth	Experienced Consultants LLC
12/4/2003	Structure of the Market	We recommend that the panel endorse: consolidation of contiguous control areas, operations of consolidated control areas by independent entities, consolidation process begins as soon as possible.	Chris Booth	Experienced Consultants LLC
11/28/2003	Emergency Plans	Digitization did not add long period oscillations. The August 14, 2003 Blackout has some similarities to the June 12, 1992 Rush Island event[1]. Large power oscillations occurred due to the reconfiguration of the grid as the result of an insulator failure at the Tyson 345 KV substation. This resulted in an unstable operating point and caused voltage collapse after about 38 minutes.To confirm that the 'digitization' did not add the observed oscillations, we ran FFTs on actual frequency data from the Arbiter 1133A Power Sentinel located in the Western interconnection. These data are measured 20 times per second and have an accuracy of better than 100 µHz. Long-period oscillations also appear on these FFTs, confirming our conjecture that digitization did not add long period oscillations.	Chuck Wells	OSISoft
11/20/2003	VAR/TECH	a) Establish rules and tools similar to WECC where system is required to operate a given distance from the maximum loading point under N-1 and N-2 contingency criteria, allowing operators to intervene when conditions are violated b.Introduce protective devices+C83 such as undervoltage load relays and ULTC tap blocking on the load side to avoid load recovery problems. See http://electricity.doe.gov/govforums/documents/comments/112003_0001.pdf)	Claudio A. Cañizares	University of Waterloo, Ontario Canada
11/20/2003	EDIT/VAR	A couple of issues associated with power system voltage stability that I think are not dealt with properly in the report. Correct definitions for voltage stability and voltage collapse per IEEE CIGRE document soon to be released "Definition and Classification of Power System Stability" See (http://electricity.doe.gov/govforums/documents/comments/112003_0001.pdf) Improve discussion on pg 63.	Claudio A. Cañizares	University of Waterloo, Ontario Canada
1/12/2003	Reliability Standards	1. Reinforce the existing NERC Compliance Enforcement Program to verify and report compliance with existing reliability standards and policies.	David Cook	NERC
1/12/2003	Training	2. Establish a program of Control Area and Reliability Coordinator reliability readiness audits.	David Cook	NERC

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/12/2003	Vegetation Management	3. Establish a program to report bulk transmission line outages caused by vegetation.	David Cook	NERC
1/12/2003	Standards Development	4. Establish a program to track implementation of recommendations.	David Cook	NERC
1/12/2003	System Restoration	5. Review the remediation plans of FirstEnergy, the Midwest Independent System Operator, and PJM, and monitor implementation of those plans.	David Cook	NERC
1/12/2003	Training	6. Clarify NERC operating policies and procedures defining Reliability Coordinator and Control Area functions, responsibilities, and authorities.	David Cook	NERC

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/12/2003	Communication	7. Improve mechanisms for the timely exchange of outage information among Control Areas and Reliability Coordinators.	David Cook	NERC
1/12/2003	Comment	8. Address Issues Remaining in the Functional Model. (Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	Reliability Standards	9. Reassess and accelerate the development of new reliability standards. (Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	Training	10. Complete development of the Reliability Organization certification program. (Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	Training	11. Modify personnel certification criteria to include emergency response training (Proposed Actions Requiring Analysis and Development beyond June 30, 2004) requirements and other qualifications necessary to assure reliable operations. (Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	Legislation	12. Continue to promote enactment of federal legislation enabling mandatory reliability standards. (Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	System Operations	13. Establish guidelines for real-time operating tools. (Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	Emergency Plans	14. Review operations planning and operating criteria. (Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/12/2003	Communication	15. Review operator and reliability coordinator communications. (Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	Prevention	16. Review transmission facility ratings methods and practices. (Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	VAR	17. Review reactive power and voltage control practices. (Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	System Operations	18.Review system design, planning, and study methods and practices.(Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	System Operations	19. Standardize the criteria for system modeling and data exchange methods and practices.(Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	Communication	20. Facilitate the installation of time-synchronized recording devices.(Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	Safety Net	21. Evaluate alternative system protection and automatic remediation schemes. (Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/12/2003	System Operations	22. Establish a reliability performance monitoring function. (Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	Training	23. Review lessons learned from August 14, 2003 regarding system restoration and black start. (Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/12/2003	Editorial Comment	24. August 14 data availability and management. NERC and the Reliability Regions should develop a data management capability to more effectively and efficiently assemble data following a large-scale blackout or disturbance.(Proposed Actions Requiring Analysis and Development beyond June 30, 2004)	David Cook	NERC
1/20/2004	Prevention	Certain NERC operating policies and planning standards were violated by particular parties, and those violations contributed directly to the start of the cascading blackout.The process for monitoring and assuring compliance with NERC and regional reliability standards was shown to be inadequate in its current form for identifying and resolving specific compliance violations before they lead to a cascading blackout.	David Cook	NERC
1/20/2004	Reliability Standards	Reliability coordinators and control areas have adopted differing interpretations of the functions, responsibilities, authorities, and capabilities necessary to operate a reliable power system.	David Cook	NERC
1/20/2004	Technical operating procedures	Lessons learned from prior large-scale blackouts were repeated, including the need for effective vegetation management, operator training, and tools to help operators better visualize system conditions.	David Cook	NERC
1/20/2004	Prevention	In some regions, data used to model loads and generators were inaccurate due to a lack of verification through benchmarking. Planning studies, design assumptions, and facilities ratings were not being consistently shared and were not sufficiently subject to peer review among operating entities and regions.	David Cook	NERC
1/20/2004	Investment	Available system protection technologies were not consistently applied in a manner that could help to slow or stop an uncontrolled cascading failure of the power system	David Cook	NERC
1/20/2004	Reliability Standards	Immediately Correct the Direct Causes of the August 14, 2003 Blackout. NERC shall take firm and immediate action to ensure that these same deficiencies do not recur and thereby place the interconnected power system at unnecessary risk of a similar cascading outage. NERC must assure electricity customers, regulators and others with an interest in reliable delivery of electricity that the power system is being operated in a manner that is safe and reliable, and that the causes of the August 14, 2003 blackout have been cured.	David Cook	NERC
1/20/2004	Comment	FE, MISO, and PJM shall each complete the remedial actions designated in Attachment A for their respective organizations and certify to the NERC Board no later than June 30, 2004 that these specified actions have been completed. Furthermore, each named organization shall	David Cook	NERC

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/20/2004	Comment	The Technical Steering Committee shall assign a team of experts to be available to assist FE, MISO, and PJM in developing plans that adequately address the issues listed in Attachment A, and other remedial actions for which each entity may seek technical assistance.	David Cook	NERC
1/20/2004	Legislation	In the absence of appropriate U.S. legislation and complementary Canadian actions, NERC continues to suffer from a lack of legally sanctioned authority to enforce compliance with its standards. NERC and the regional reliability councils must assume a greater authority to measure compliance, to more transparently report significant violations that could risk the integrity of the interconnected power system, and to take firm actions to assure violations are corrected.	David Cook	NERC
1/20/2004	Structure of the Market/ Reliability standards	Each regional reliability council shall report monthly to the NERC Board, through the NERC Compliance Program, all violations of NERC Operating Policies and Planning Standards and regional standards that could have a measurable impact on the reliability of the interconnected power systems. Such reports shall confidentially note details regarding the nature and potential reliability impacts of violations and the identity of parties which are found to be non-compliant with NERC and regional standards. The Board, with due consideration of all the facts and circumstances surrounding any significant violation, shall request the offending organization to correct the violation within a specified time. If the Board determines that the offending organization is non-responsive and continues to cause a risk to the reliability of the interconnected power systems, the Board will seek to remedy the violation by requesting any necessary assistance of the appropriate regulatory authorities in the United States and Canada.	David Cook	NERC
1/20/2004	Standards development	The Compliance Enforcement Program shall a) review and update its compliance templates for existing NERC operating policies and planning standards, b) submit any modifications or new templates to the Board for approval no later than March 31, 2004, and c) subsequently issue approved compliance templates to the regional reliability councils for adoption into their compliance monitoring programs.	David Cook	NERC
1/20/2004	Structure of the market	The NERC Compliance Enforcement Program and the regional reliability councils shall establish a program to audit the reliability readiness of all reliability coordinators and control areas, with immediate attention given to addressing the deficiencies identified in the August 14, 2003 blackout. Audits of all control areas and reliability coordinators are to be initially completed within two years, with audits continuing after that on a three-year cycle. The 25 highest priority audits will be completed by June 30, 2004.	David Cook	NERC
1/20/2004	Reliability Standards	NERC will establish a baseline set of audit criteria to which the regions may add regional criteria. The control area requirements will be based on the existing NERC Control Area Certification Procedure. Reliability coordinator audits will include evaluation of reliability plans, procedures, processes, tools, personnel qualifications, and training. In addition to reviewing written documents, the audits will carefully examine the actual practices and preparedness of control areas and reliability coordinators.	David Cook	NERC

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/20/2004	Structure of the market	The reliability regions, with the oversight and participation of NERC, will audit each control area's and reliability coordinator's readiness to meet these audit criteria. All control areas and reliability coordinators will be audited within two years of the program's initiation and every three years thereafter. NERC staff will participate directly on the regional audit teams. FERC and other relevant regulatory agencies will be permitted to participate in the audits on request, subject to the same confidentiality conditions as the other members of the audit teams.	David Cook	NERC
1/20/2004	Vegetation management	NERC will focus initially on measuring performance as indicated by the number of high voltage line trips caused by vegetation rather than develop standards for right-of-way maintenance. This approach has worked well with a similar program initiated in WECC following the 1996 outages in the west. NERC and the regional reliability councils shall jointly initiate a program to report all bulk electric system transmission line forced outages resulting from vegetation contact. The program will use the successful Western Electricity Coordinating Council (WECC) vegetation monitoring program as a model.	David Cook	NERC
1/20/2004	Vegetation management	Each transmission operator will submit an annual report of all vegetation-related forced outages to its respective reliability region. Each region will assemble a detailed annual report of vegetation-related outages in the region to NERC no later than March 31 for the preceding year. Based on the results of these reports, NERC will consider the need for standards related to vegetation management. Each bulk electric transmission operator shall publish its vegetation management procedure so as to be available from its public web site. The procedure shall include at a minimum the frequency of right-of-way trimming and inspection.	David Cook	NERC
1/20/2004	Vegetation management	Each transmission operator will submit an annual report of all vegetation-related forced outages to its respective reliability region. Each region will assemble a detailed annual report of vegetation-related outages in the region to NERC no later than March 31 for the preceding year. Based on the results of these reports, NERC will consider the need for standards related to vegetation management. Each bulk electric transmission operator shall publish its vegetation management procedure so as to be available from its public web site. The procedure shall include at a minimum the frequency of right-of-way trimming and inspection.	David Cook	NERC
1/20/2004	Comment	NERC and each regional reliability council shall establish a program for documenting completion of recommendations resulting from the August 14 blackout and other historical outages, and NERC and regional reports on reliability violations, compliance audits, and system disturbance reports. Regions will report quarterly to NERC on the status of follow-up actions to address recommendations. NERC staff will report both NERC activities and a summary of regional activities to the Board.	David Cook	NERC
1/20/2004	Reliability Standards	Assuring compliance with reliability standards, evaluating the reliability readiness of reliability coordinators and control areas, and assuring recommended actions are achieved will be effective steps in reducing the chances of future large-scale outages. However, it is important for NERC to also facilitate continuous learning by developing tangible feedback from outages, disturbances, near misses, and reliability trends.	David Cook	NERC

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/20/2004	Reliability Standards	NERC shall establish a reliability performance monitoring function to evaluate and report bulk electric system reliability performance. Such a function would assess large-scale outages and near misses to determine root causes and lessons learned, similar to the August 14, 2003 blackout investigation. This function would incorporate the current Disturbance Analysis WG and expand that work to provide more proactive feedback to the NERC Board regarding reliability performance. This program would also gather and analyze reliability performance statistics to inform the Board of reliability trends and develop procedures and capabilities to initiate investigations in the event of future large-scale outages or disturbances. Such procedures and capabilities would be shared among NERC and regional councils for use as needed, with NERC and regional council investigation roles clearly defined in advance.	David Cook	NERC
1/20/2004	Reliability Standards	All reliability coordinators and control areas shall provide all real-time system operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel. An initial five days of training and drills are to be completed prior to June 30, 2004. Training records are to be available during reliability readiness audits.	David Cook	NERC
1/20/2004	Training	In the longer term, the NERC Operator Certification Governing Board, which is independent of the NERC Board, should explore expanding the NERC certification requirements of system operating personnel to include minimum training and continuing education requirements, such as emergency training using realistic simulations. The current NERC certification examination, which is limited to testing knowledge of the NERC Operating Policies, is by itself an inadequate demonstration of competency to operate a reliable electric system.	David Cook	NERC
1/20/2004	Prevention	The Planning Committee shall evaluate the effectiveness of existing reactive power and voltage control standards and practices, including static and dynamic reactive power reserves. The evaluation will focus on assuring the bulk electric system does not approach unstable voltage conditions and that systems do not adversely impact voltage profiles or reactive supply of other systems.	David Cook	NERC
1/20/2004	Emergency plans	The investigators believe that two measures could have been taken to slow or stop the uncontrolled cascade on August 14. First, beginning with the Sammis-Star line trip at 16:05:57, most of the line trips during the cascade phase were the result of the operation of a zone 3 relay for a perceived overload or power swing on the protected line. If used, zone 3 relays typically act as an overreaching backup to the zone 1 and 2 relays and should not operate on a line overload. Under extreme conditions of low voltages and large power swings as seen on August 14, however, the zone 3 relay operations can serve to unnecessarily propagate the outage to a wider area.	David Cook	NERC

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/20/2004	Emergency plans	All transmission operators shall, no later than June 30, 2004, evaluate zone 3 relay settings on all transmission lines operating at 230 kV and above and ensure each zone 3 setting has at least a 50% load margin above the emergency rating of the line, assuming .85 per unit voltage and a line phase angle of 30 degrees. If these criteria cannot be met, transmission operators should either replace the relay with a digital relay with such capability or mitigate the overreach of the zone 3 relay. The overall objective is to ensure that zone 3 relays do not trip on load under extreme emergency conditions.	David Cook	NERC
1/20/2004	Comment	A second key finding with regard to system protection was that if an automatic under-voltage load shedding scheme had been in place in the Cleveland-Akron area, there is a high probability the outage could have been limited to that area.	David Cook	NERC
1/20/2004	System Operations	Each regional reliability council shall complete an evaluation of the feasibility and benefits of installing under-voltage load shedding capability in load centers within the region which could become unstable as a result of being deficient in reactive power following credible multiple-contingency events. The regions are complete the evaluation and report the results to NERC within one year. The regions are requested to promote the installation of under-voltage load shedding capabilities within their areas, as determined by study to be effective in preventing an uncontrolled cascade of the power system.	David Cook	NERC
1/20/2004	Prevention	The Planning Committee shall evaluate Planning Standard III and propose within one year specific revisions to the criteria to adequately address the issue of slowing or limiting the propagation of a cascade. The Board directs the Planning Committee to evaluate the lessons from August 14, 2003 regarding relay protection design and application and offer additional recommendations for improvement.	David Cook	NERC
1/20/2004	System Operations	The Operating Committee shall complete the following by June 30, 2004: Evaluate and revise the operating policies and procedures to ensure reliability coordinator and control area functions, responsibilities, and authorities are completely and unambiguously defined. Evaluate and improve the tools and procedures for operator and reliability coordinator communications during emergencies. Evaluate and improve the tools and procedures for the timely exchange of outage information among control areas and reliability coordinators.	David Cook	NERC
1/20/2004	System Operations	The Operating Committee shall within one year evaluate the real-time operating tools necessary for reliable operation and reliability coordination, including backup capabilities. The Operating Committee is directed to report both minimum acceptable capabilities for critical reliability functions and a guide of best practices.	David Cook	NERC
1/20/2004	Prevention	The Planning Committee shall, working jointly with NPCC, ECAR, and PJM, review the black start and system restoration performance following the outage of August 14, and to make recommendations for improvement by December 31, 2004.	David Cook	NERC

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/20/2004	Reliability Standards	The reliability regions, coordinated through the NERC Planning Committee, shall define regional criteria for the application of synchronized recording devices in power plants and substations, such as phasor measurement units and digital fault recorders. Regions are requested to facilitate the installation of an appropriate number, type and location of devices within the region to allow accurate recording of future system disturbances and to facilitate benchmarking of simulation studies by comparison to actual disturbances.	David Cook	NERC
1/20/2004	System Operations	The Operating Committee shall evaluate operations planning and operating criteria and recommend revisions within one year.	David Cook	NERC
1/20/2004	Prevention	The Planning Committee within two years shall reevaluate system design, planning, and study criteria, methods and practices, to reevaluate transmission facility ratings methods and practices, and to recommend revisions.	David Cook	NERC
1/20/2004	Reliability Standards	The reliability regions shall establish criteria and procedures for benchmarking of power flow models and dynamic simulations with actual system performance to ensure accurate and reliable models, and ensure such benchmarking occurs in the region.	David Cook	NERC
1/20/2004	Legislation	Promote enactment of federal legislation enabling mandatory reliability standards. NERC will continue to promote enactment of reliability legislation. NERC will continue preparing for a smooth transition from the current voluntary approach to setting and enforcing mandatory reliability standards.	David Cook	NERC
1/20/2004	Reliability Standards	Develop new reliability standards. NERC will continue developing new reliability standards, and revise emerging standards or initiate new standards as necessary to address all reliability lessons learned. Reliability standards will be stated with sufficient detail to ensure that, if followed, the standards would be effective in preventing future cascading outages. New reliability standards will be available for adoption as soon as possible, with a target of completion by December 2006, and will include a plan for the smooth transition from existing operating policies and planning standards. NERC will seek opportunities to accelerate the adoption of reliability standards.	David Cook	NERC
1/20/2004	Technical operating procedures	Complete development of the Reliability Organization certification program. NERC will complete the development and adoption of certification criteria for reliability functions identified in the Functional Model, including Reliability Authorities, Balancing Authorities, Interchange Authorities, and Transmission Operators. NERC will register all entities providing these reliability functions by December 2004 and initially certify all registered reliability entities by December 2006.	David Cook	NERC

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/20/2004	Mandate	FirstEnergy shall complete the following corrective actions by June 30, 2004. Unless otherwise stated, the requirements apply to FE's northern Ohio system. The investigation team found that FE was not operating on August 14 within NERC planning and operating criteria with respect to its voltage profile and reactive power supply margin in the Cleveland-Akron area. FE shall, consistent with or as part of the FERC-ordered study, determine the minimum location-specific voltages at all 345 kV and 138 kV buses and all generating stations. FE shall determine the minimum dynamic reactive reserves that must be maintained in local areas to ensure that these minimum voltages are met following studied contingencies. FE shall determine voltage and reactive criteria and procedures to enable operators to understand and operate to these criteria. When the FERC-ordered study is completed, FE is to adopt the planning and operating criteria determined as a result of that study and update the operating criteria and procedures for its system operators.	David Cook	NERC
1/20/2004	Mandate	FE shall inspect all reactive resources and assure that all are fully operational. FE shall verify that all installed capacitors have no blown fuses and that at least 98% of installed capacitors are available and in service during the summer 2004. FE shall communicate its voltage criteria and procedures, as described in the items above to MISO and FE's neighboring system.	David Cook	NERC
1/20/2004	Mandate	FE shall prepare and submit to ECAR, with a copy to NERC, an Operational Preparedness and Action Plan to ensure system security and full compliance with NERC and planning and operating criteria, including ECAR Document 1: 2004 summer studies, extreme contingencies, maximum import capability, vegetation management, and line ratings.	David Cook	NERC
1/20/2004	Mandate	FE shall develop a capability no later than June 30, 2004 to reduce load in the Cleveland-Akron area by 1500 MW within ten minutes of a directive to do so by MISO or the FE system operator. FE shall develop emergency response plans, including plans to deploy the load reduction capabilities noted above. The plan shall include criteria for declaring and emergency and various states of emergency.	David Cook	NERC
1/20/2004	Mandate	FE shall conduct a thorough review of its protection on the 345/138 kV facilities starting with those which are considered to have a significant impact on the interconnection.	David Cook	NERC
1/20/2004	Mandate	FE shall develop communications procedures for FE operating personnel to use within FE, with MISO and neighboring systems, and others. FE shall ensure its state estimation and real-time contingency analysis functions are able to reliably execute full contingency analysis automatically every ten minutes and alarm operators of potential first contingency violations.FE shall provide its operating personnel with the capability to visualize the status of the power system from an overview perspective and to determine critical system failures or unsafe conditions at a quickly without multiple-step searches for failures. A dynamic map board or equivalent capability is encouraged.	David Cook	NERC

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/20/2004	Mandate	FE shall develop and prepare to implement a plan for the loss of it system operating center or any portion of its critical operating functions.FE shall implement all current known fixes for the GE XA21 system necessary to assure reliable and stable operation of critical reliability functions, and particularly to correct the alarm processor failure that occurred on August 14, 2003.	David Cook	NERC
1/20/2004	Mandate	Prior to June 30, 2004 each FE operator shall have at least five full days off-shift dedicated to training and drills on system emergencies. Such training and drills shall include realistic simulations, including use of a realistic model of the FE system, and shall comply with the NERC Operating Policy 8 requirements for approved training providers and approved learning activities.	David Cook	NERC
1/20/2004	Mandate	MISO shall complete fully implement and test its topology processor to provide its operating personnel real-time view of the system status for all transmission lines operating and all generating units within its system, and all critical transmission lines and generating units in neighboring systems. Alarms should be provided for operators for all critical transmission line outages. MISO shall establish a means of exchanging outage information with its members and neighboring systems such that the MISO state estimation has accurate and timely information to perform as designed. MISO shall fully implement and test its state estimation and real-time contingency analysis tools to ensure they can operate reliably every no less than every ten minutes.	David Cook	NERC
1/20/2004	Mandate	MISO shall provide its operating personnel tools to quickly visualize system status and failures of key lines, generators or equipment. The visualization shall include a high level voltage profile of the systems within the MISO footprint.	David Cook	NERC
1/20/2004	Mandate	Prior to June 30, 2004 each MISO operator shall have at least five full days off-shift dedicated to training and drills on system emergencies. MISO shall reevaluate and improve its communications protocols and procedures with operational support personnel within MISO, its operating members, and its neighboring control areas and reliability coordinators.	David Cook	NERC
1/20/2004	Mandate	MISO shall reevaluate its operating agreements with member entities to verify its authority to address operating issues, including voltage and reactive management, voltage scheduling, the deployment and redispatch of real and reactive reserves for emergency response, and the authority to direct actions during system emergencies, including shedding load.	David Cook	NERC
1/20/2004	Mandate	PJM shall complete the following corrective actions no later than June 30, 2004. PJM shall reevaluate and improve its communications protocols and procedures with operational support personnel within PJM, its operating members, and its neighboring control areas and reliability coordinators.	David Cook	NERC
12/19/2003	Comment	In recent years, UWUA has observed a trend of declining maintenance coinciding with dramatic cutbacks in electric utility staffing.	Donald Wightman	Utility Workers Union of America

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/19/2003	Vegetation Management	The Task Force does not examine the reason why this fundamental component of utility system maintenance was apparently not performed with respect to portions of the FirstEnergy system. The Interim Report highlights failures to perform tree trimming as a central cause of the August 14 Blackout; the Final Report should examine the root causes of these failures to perform basic system maintenance.	Donald Wightman	Utility Workers Union of America
12/19/2003	Training	No utility can provide safe and reliable service unless it has an adequate complement of utility workers.	Donald Wightman	Utility Workers Union of America
12/19/2003	Grid Integration	The Final report should emphasize the importance of electric system maintenance.	Donald Wightman	Utility Workers Union of America
11/20/2003	System Operations	On page 29, where the report talks about the failure of FE's software: "Analysis of the alarm problem performed by FE suggests that the alarm process essentially "stalled" while processing an alarm event, such that the process began to run in a manner that failed to complete the processing of that alarm or produce any other valid output (alarms)."As a professional software engineer with 25 years of experience, I find this explanation totally insufficient. There's a bug in the software somewhere and I would like to know what it is, how it got there, and why it wasn't discovered during development and testing.	Douglas B Rupp	Ada Core Technologies, Inc.
11/20/2003	EDIT	Typo on page 51: "In this manned, most of New England remained energized." Probably you meant "In this manner."	Douglas B Rupp	Ada Core Technologies, Inc.
12/4/2003	Investment	To enhance grid reliability and quality, and to begin to reduce the possibility of another cascading outage we suggest a) Implement a grid status monitoring, communication and notification system that operates independently of existing SCADA/EMS systems, and that provides interregional visibility to power grid status in near real-time; b) Establish and enforce uniform grid reliability standards; the development of environmentally benign solutions that can help reduce transmission level congestion, thus increasing grid reliability while improving asset utilization; c)Create regulatory certainty by allowing transmission owners to share in the benefits of competitive markets, such that these financial incentives will drive infrastructure investments; d)Rapidly implement recommended changes to minimize the possibility of future cascading outages.	Dr. Deepak Divan, Fellow IEEE	Soft Switching Technologies

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/4/2003	Invesment	Soft Switching has approximately 200 power monitors installed in the blackout area. We were able to track the progress of the blackout using our I-Grid system, thereby gaining a unique perspective on the blackout. Based on our data I can report that the laws of physics still work, and I am afraid they will continue to work to our detriment unless we take steps to modernize the power grid. We have two primary technology and product thrusts that can have a significant impact on grid reliability and quality: a) an Internet based power monitoring product, the I-Grid, and, b) a new technology that can directly impact the problem of transmission line congestion.	Dr. Deepak Divan, Fellow IEEE	Soft Switching Technologies
12/5/2003	Comment	Provided two papers as resumes for his work. One, “Future Outlook For Pipeline Materials, Methods, And maintenance,” and the second was “Creative Ways to Build Broadband Networks And Underground Power Cables Through Strategic Partnerships Among Utilities.” They can be found at: http://home.earthlink.net/~jkjeyapalan/intro	Dr. Jey K. Jeyapalan, P.E.	Jeyapalan & Associates, LLC
12/1/2003	EDIT	The Report (Page-15) eliminates "Low Reactive power output from IPPs" from the possible causes of black out and (Page 18), suggests that IPPs may have contributed to the difficulties of reliability management on August 14 because they do not provide reactive power. What the IPP is required to produce is governed by contractual arrangements, which usually include provisions for contributions to reliability, particularly during system emergencies. More importantly, it is the responsibility of system planners and operators, not IPPs, to plan for reactive power requirements and make any short-term arrangements needed to ensure that adequate reactive power resources will be available."	Dr. K K Das	IEEE Member, PowerGrid Corporation of India Limited
12/1/2003	Technical Operating Procedures	(a)How much active power was produced / generated by the IPPs ? The power flow data (Page 18) on August 14 show that First Energy's (FE) load was 12080 MW. FE was importing 2575 MW and generating the remainder i.e. 9505 MW. The report is silent about the quantum of MW generated by IPPs out of 9505 MW. (b) How much reactive power was produced by the IPPs ? Were these plants producing reactive (MVAr) at their capability/ output limits? The report states (page 24) "as directed in FE's Manual of Operations, reliability operator began to call plant operators to ask for additional voltage support form their units. He noted to most of them that system voltages were sagging, "all over." Several mentioned that they were already at or near their reactive output limit. The report is silent about the quantum of reactive generation by IPPS.	Dr. K K Das	IEEE Member, PowerGrid Corporation of India Limited
12/1/2003	System Operations	The Task Force may check the actions taken by IPP. They may also check the actual power plant logs to verify that the plants are at their reactive out put limits.We feel this is an essential requirement to clear public mind of any misplaced notions. This is more important as because Eastlake 5(597 MW) tripped when the operator sought to increase the unit's reactive power output. The investigation team's system simulations also indicate (Page 28) that the loss of Eastlake 5 was a critical step in the sequence of events	Dr. K K Das	IEEE Member, PowerGrid Corporation of India Limited
12/5/2003	Reliability Standards	Recommendation for the establishment of mandatory reliability rules as a firm foundation for the minimization of the risk of future blackouts, provided that more stringent reliability standards may continue to be promulgated by regional and local entities.	Dr. Mayer Sasson	NYSRC

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/5/2003	Reliability Standards	The recommendation we therefore wish to make today is for having national, regional and local reliability rules that recognize special regional and local conditions, and having such rules mandatory over all entities that design and operate the power system as well as over all market participants that use the transmission system. There must also be a compliance function to monitor observance of such rules.	Dr. Mayer Sasson	NYSRC
11/30/2003	Editorial Comment	I recently completed a review of the above-referenced report. Having been in the transmission and generation study and development business for the best part of 30 years I think I know a good report when I see one. This report is exceptionally well done. It is very nicely organized. It is written in a clear and understandable manner. The visuals are excellent. And the periodic text inserts describing various technical matters are a nice touch - both for the newcomer and for the one needing a reminder.	Eddie Kolodziej	Personal comment
11/30/2003	EDIT	page 5, Figure 2.4 indicates that generation underfrequency trips occur at about 58.5 Hz. However, the text box on "Under-frequency Load-Shedding" at the bottom of page 59 indicates that the set point for generation underfrequency relays is 57.5 Hz.	Eddie Kolodziej	Personal comment
11/30/2003	EDIT	On page 22, first paragraph, the second sentence states, "FirstEnergy (FE) was importing approximately 2,000 MW into its service territory, causing its system to consume high levels of reactive power." (Emphasis added.) Sending megawatts into FE did not cause FE's system to consume VARs. "watts flow down the power angle and VARs flow down the voltage." VARs were most likely consumed because of FE's operation at low system voltages as noted on page 18 where it is stated that it is FE's policy of allowing a 92% level to be deemed normal. If this is true and if FE's neighbors are operating at the more recognized norm of 95% voltage, then FE will always be pulling VARs from those neighbors - regardless of power flow direction.	Eddie Kolodziej	Personal comment
12/4/2003	Standards Development	The reported triggering events and the poor responses to those events may also be linked by a pattern of mismanagement that should be explored further by the Task Force. The Task Force should also consider other causes related to the lack of information sharing.	Eric B. Stephens	Ohio Consumers' Counsel (OCC)

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/4/2003	Vegetation Management	The Task Force should report on the actual vegetation maintenance practices of FirstEnergy and DPL. The Task Force should report whether utilities are deviating from stated policies in order to add to profits while sacrificing the reliability of the transmission system. Utilities should be subject to mandatory, enforceable standards regarding the maintenances of their right-of-ways to ensure reliability, and they should be held accountable for the harm caused by inadequate practices.	Eric B. Stephens	Ohio Consumers' Counsel (OCC)
12/4/2003	System Operations	The Task Force's Interim Report on the Causes of the August 14" Blackout ("Interim Report") raises serious questions concerning the reliability of transmission lines that serve Ohioans. On November 25, 2003, Ohio's Public Utility Commission ordered FirstEnergy to "develop a plan to address certain problems identified by the Task Force and ensure that the problems will not reoccur." The OCC is hopeful that the Ohio Commission's efforts will be worthwhile. However, a federal effort that explores the operation of FirstEnergy's transmission system is both desirable and needed in order to provide the best insights into how further outages can be prevented.	Eric B. Stephens	Ohio Consumers' Counsel (OCC)
12/4/2003	Reliability Standards	Our comments emphasize that priority should not be given to such false and expensive "solutions," but rather to improvements that deal with vegetation maintenance, reporting and inspection, training requirements, and better management of utility operations. Operation of the transmission system should be governed by mandatory, enforceable standards.	Eric B. Stephens	Ohio Consumers' Counsel (OCC)
21/4/03	Legislation	Federal legislation to accomplish this goal should move forward immediately, and on a stand-alone basis if necessary.	Eric B. Stephens	Ohio Consumers' Counsel (OCC)
12/4/2003	Market and Deregulation	Finally, other important enhancements to the Midwestern portion of the transmission grid are linked to structural changes in the industry such as RTO development that provides for "seamless" operation across RTO boundaries.	Eric B. Stephens	Ohio Consumers' Counsel (OCC)

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/17/2003	Training	We recommend that teams of experienced operators and engineers define the overall requirements needed to operate a reliable power system. The recommended investigation requires that the industry clearly and specifically state its mission, goals and objectives with regard to reliability. The team should identify the full range of issues that can affect the reliable operation of a power system. Once identified, the relative contribution of each issue to the reliable operation of the power system can be accessed and dealt with. This investigation should also cover the operational relationship between the operating center and the RTO/ISO.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/17/2003	Standards Development	What we have to date is a scattered set of recommendations addressing parts of the issues impacting system operation but nothing that looks at the issues in a broad context. Nothing tells us if we will achieve a set of overall objectives. All relevant components of the operating environment (institutions, technological systems and operators) should be examined by groups of experienced operators and engineers to see if they contribute to meeting reliability objectives. If not, recommendations should be made as needed for improvements. If, after due deliberation, reliability goals cannot be achieved by normal means, different strategies may need to be developed; under no circumstance, however, should reliability standards be watered down.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/17/2003	Structure of the Market	As an illustrative example, consider a few, but not all, of the issues that could be addressed when evaluating whether a system control center/operator can meet the requirement to adjust power flows power flows following a contingency within a specified time period so as to be able to survive another contingency.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/17/2003	Training	How does an operator know a contingency has occurred? How is the information presented to him? How long does it take him to receive and digest the information? How reliable and accurate is the information? Does the operator need confirmation that the information is correct? Does he know the full impact of the contingency - all lines and generators out of service, all line flows and voltages? Does he have to request an impact analysis indicating to him the severity of the outage or is it done automatically for him? Does the analysis consider all relevant issues; thermal line loadings, voltage and stability limits?	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/17/2003	Training	How good is the data about the system needed for the analysis, i.e. generators and transmission lines in service, their ratings/capabilities, the line impedances, the generator impedances, time constants etc? Are there sufficient personnel, both operating and support, at the control center to ensure reliable operation? What reliability criteria are being used? When power flows, voltages, or other system conditions are found to be beyond the range of the specified criteria, how much time is permitted to get system conditions within appropriate limits? Does the operator have the necessary human or computer help analyzing the situation or is he on his own?	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/6/2004	Editorial Comment	The Interim Report on the Blackout alleges that cascading of the transmission system was not a classic case of voltage collapse (page 63), but nevertheless, the report cites many references to low voltages and operator actions to correct this situation (pages 18, 19, 23, 24). In fact, the action at the Eastlake #5 to increase reactive output to support low voltages resulted in its trip-out, further exacerbating a sagging voltage condition in the First Energy load area (page 24). The report also states that voltage was a factor in some of the events that led to the ultimate	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/6/2004	Safety Net	The trip-out of Eastlake #5 increased MW line flows on the heavily loaded transmission lines into the Cleveland - Akron load area, increased reactive power flows into this area from other parts of the system and further aggravated an already deteriorating voltage situation in this area. This deteriorating condition was further exacerbated by the subsequent tripping of the 345-kV transmission lines serving the northern Ohio load area and contributed to the subsequent tripping of the many 138-kV transmission lines in northern Ohio due to the operation of 3rd zone relaying (page 50).	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/6/2004	System Operations	Notwithstanding the basic contention in the Interim Report that voltage was not a root cause of the blackout, all evidence available strongly suggests that deteriorating voltage conditions were a major contributor to the many events leading up to the cascading of the transmission system in northern Ohio and the ultimate blackout in many areas. This raises a serious concern as to whether the importance of adequate reactive supply and good voltage support is adequately	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/6/2004	Standards Development	The industry needs to establish a coordinated and consistent voltage criteria for the operation of the transmission grid reflecting the transmission and generation facilities in service and the power transfers expected. The criteria should include the allowable voltage gradient across the grid as well as allowable voltage drops at any transmission station following a contingency. The industry also should address the requirement for maintaining adequate reactive reserves in the event of unanticipated outages.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/6/2004	VAR	Reactive power cannot be efficiently transmitted across the transmission system without causing reduced voltages. Therefore sufficient reactive supply needs to be installed throughout the system and especially near customer load centers to minimize the flow of reactive power across the transmission system at the required levels of real power transfer.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/6/2004	VAR	In planning the reactive supply to maintain adequate voltage levels during all expected operating conditions, systems should give consideration to the installation of automatic under-voltage load shedding to provide a means of controlling voltages for unexpected extreme system emergencies.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/6/2004	Editorial Comment	It must be recognized that the true rating of any piece of transmission equipment is its current carrying capability and that ratings in terms of MW or MVA can give a false indication of the true capability due to the influence of voltage. Therefore, transmission line ratings should be expressed and monitored in terms of amperes.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/6/2004	Communication	Acceptable voltage at key transmission stations should be specified by every transmission operator and communicated to all affected operational entities.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/6/2004	Standards Development	The daily and hourly security analyses of the transmission system carried out at the control center and ISO/RTO are usually based on simplified linear load flow techniques. These analyses should be expanded to explicitly consider voltage conditions on the system. In addition, such security analyses should take into account the de-rating or unavailability of reactive sources.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/6/2004	Standards Development	An industry wide effort should be made to better define the load power factor (reactive power component of the load) used in planning and operational analysis studies. This effort should include regular benchmarking of system models to actual system conditions.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/6/2004	Safety Net	Generator MVAR capabilities should be regularly audited and be available to both the operators on duty and used in the operational studies to establish safe operating limits.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/6/2004	Communication	Information on actual generator MVAR capabilities versus MW loading levels should be available to the operators at the control centers as well as the ISO/RTO or Regional Reliability Coordinator.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/6/2004	Standards Development	Approval of IPP contracts by responsible authorities should require that the contract contain specific directions regarding the supply of reactive power by the IPP in the event of an emergency condition on the transmission system.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
1/6/2004	Standards Development	Operator responses to low system voltage should be pre-determined and provision made at control centers to rapidly implement any corrective actions. Such information should also be available to the RTO.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
12/12/2003	Structure of the Market	Table 6.1 in the report shows the complexities added by the restructuring of the electric power industry mandated by the Federal and state governments. The Report also contains many references to a wide range of deficiencies in the coordination of the operation of the bulk power	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M.	Power Engineers Seeking Truth
12/12/2003	Training	The Report should examine the role of NERC and the Reliability Councils in operator training and qualification and control center and RTO certification.	F. J. Delea, J. A. Casazza, G.C.	Power Engineers Seeking Truth
12/12/2003	System Operations	In the Report, the role of low transmission voltage is not fully investigated as a contributor to the blackout. Low voltages can have a number of significant impacts on system performance. The table on Page 23,"Causes of the Blackout", does not list low voltage as a cause although the section on Page 18 entitled "Voltages" refers to depressed voltages on the system and attempts by operators at FE and in other areas to maintain voltage. On Page 63 the Report states that "low voltage never became the primary cause of line and generator tripping". However, on the same page, reference is made to the loss of generation because of "excitation system failures during extremely low voltage conditions on portions of the power system."	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
12/12/2003	System Operations	The Report also does not examine the results of operator efforts to maintain voltages including responses to their requests for additional voltage support from generators and the efficiency of	F. J. Delea, J. A. Casazza, G.C.	Power Engineers Seeking Truth

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/12/2003	VAR	The Report should more thoroughly examine the role of low voltage as a contributor to the blackout. It should also address the voltage and frequency transients that existed earlier in the day on August 14 to see if there were any indications of sub-synchronous resonance problems that may have contributed to some of the outages.	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
12/12/2003	VAR	Were the results of the computer simulations used to reach conclusions in the report checked against actual system line loading and voltage data at various time and location points as the sequence of events developed. Were there instances where actual system data and the computer step by step data did not check? What was done in these situations?	F. J. Delea, J. A. Casazza, G.C. Loehr and R.M. Maliszewski	Power Engineers Seeking Truth
11/22/2003	Edit	Page 5, Second Bullet: The first mention of the "N-1 criterion" is understandable to professionals in the power industry but, I noticed that it is not included in the Appendix B "List of Electricity Acronyms". It may make it easier for others if they can quickly reference it there, even though the report does explain what it means a few pages after this first reference to it.	Glenn W. Brown	New Brunswick Power Corp.NPCC Representative & Chairman,NERC Disturbance Analysis Working Group
11/22/2003	Edit	Page 5, Item 2: Near the end of the paragraph there is a statement that low voltage can cause failure of electronic equipment. I always thought that this was mainly a worry for high voltage events?	Glenn W. Brown	New Brunswick Power Corp.
11/22/2003	Edit	Page 6, last sentence of Item 3: I think it would read better to say "...power flow on transmission lines is to selectively adjust the output of generators."	Glenn W. Brown	New Brunswick Power Corp.
11/22/2003	Edit	Page 9, the Map: The NPCC section shows an hvDC link between Quebec and Ontario - none exist. The transfers of energy between them are done by isolating either load or generation onto each others system.	Glenn W. Brown	New Brunswick Power Corp.
11/22/2003	Edit	Page 6, last sentence of Item 4: I think it would be better to say "...each island would attempt to maintain its own frequency...."	Glenn W. Brown	New Brunswick Power Corp.

Date	Rec Type	Recommendations/ Comments	Name	Organization
11/22/2003	Edit	Page 16, first paragraph above Figure 3.1: The last sentence says that Fig. 3.1 shows 'peak electric demands' - it actually shows temperature ranges.	Glenn W. Brown	New Brunswick Power Corp.
11/22/2003	Edit	Page 27, first paragraph is missing a word: "Line status information within MISO's reliability coordination are is transmitted to MISO by the ECAR data network or direct links and is intended to be automatically linked to the SE".	Glenn W. Brown	New Brunswick Power Crop.
11/22/2003	Edit	Page 27, first paragraph would be clearer with: "...but to troubleshoot this problem the analyst had turned off the automatic trigger...."	Glenn W. Brown	New Brunswick Power Corp.
11/22/2003	Edit	Page 51, top right section has one "and" too many: "...protect themselves from severe damage, (remove 'and') some area completely separated themselves...."	Glenn W. Brown	New Brunswick Power Crop.
11/22/2003	Edit	Page 51, top right section, second to last sentence: Change "In this manned" to "In this manner."	Glenn W. Brown	New Brunswick Power Corp.
11/22/2003	Edit	Page 55, top right section: The second sentence refers to Figure 5.8 when it actually should refer to Figure 5.9 for voltage decay.	Glenn W. Brown	New Brunswick Power Corp.
11/22/2003	Edit	Page 58, Item 7C, second sentence: "This left most of Ontario isolated...."	Glenn W. Brown	New Brunswick Power Corp.
11/22/2003	Edit	Page 58, Item 7C, last sentence: Since the report earlier mentions that Quebec only has hvDC ties to the remainder of the Eastern Interconnection, it would be more technically correct to say that "....NYPA's 765-kV AC interconnection to their hvDC tie with Quebec...." This occurs again on Page 60 (top right paragraph) and Page 61 (top left paragraph).	Glenn W. Brown	New Brunswick Power Corp.

Date	Rec Type	Recommendations/ Comments	Name	Organization
11/22/2003	Edit	Page 59, last sentence of first paragraph: If you are going to get into decimal points, the reference to 63.0 Hz is not totally accurate (even though I helped prepare this section). If you look at the actual frequency traces supplied by Ontario, the peak frequency is about 63.4 Hz.	Glenn W. Brown	New Brunswick Power Corp.
11/22/2003	Edit	Page 60, first paragraph of Item 7E: It would read better to say "The power to serve this load came via the only major path available, through Ontario..." Not good to have two "through" in the same sentence!	Glenn W. Brown	New Brunswick Power Corp.
11/22/2003	Edit	Page 65, the bottom map: There was no generator tripping in NB (over at the right-hand side) during this time period. The middle map showing trips at Mactaquac and Beechwood in NB is correct, and these were the only elements that tripped during the entire event.	Glenn W. Brown	New Brunswick Power Corp.
11/22/2003	Edit	Page 69, second and third bullets: both refer to generators tripping off and losing "load". This is a bit confusing to the average person since we really mean that we are losing generator output or resources, not "load" in the context of the remainder of the report (i.e. customer "load".)	Glenn W. Brown	New Brunswick Power Corp.
11/22/2003	Edit	Page 78, first full paragraph on right side: This section refers to "MVAR" whereas the earlier sections referred to "MVAr" - should be consistent in the report.	Glenn W. Brown	New Brunswick Power Corp.
11/22/2003	Edit	Page 89, top left paragraph on "Pickering B": I was surprised to see that automatic controls switched both Pickering U5 and U6 AVRs over to Manual mode when the going got tough! This is exactly when you need units to be able to respond dynamically to whatever is happening on the grid. NERC has specific policies that require notification when AVRs are operated on Manual mode. I am surprised that this logic is in place and there was no comment on it in the report. None of the other generators did this during the disturbance.	Glenn W. Brown	New Brunswick Power Corp.
12/4/2003	Structure of the Market	One critical issue the Task Force must address as it proceeds to Phase II of its investigation and the Final Report is: What operating structure must be in place for an entity to perform regional operational and reliability coordination functions? First, there must be clearly defined authority. Operators should have full responsibility and authority for coordinating and scheduling major planned outages of critical power system equipment. Second, there must be a hierarchical organizational structure with the Operator at the top and no question that only “one set of hands is on the wheel” making critical operating decisions. The complexity of having over thirty-five Control Areas in the Midwest that needed to communicate operating decisions may have exacerbated the problems experienced on August 14. Third, there must be sufficient infrastructure in place for the Operator to perform its tasks efficiently.	Gordon van Welie	ISO New England Inc.

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/4/2004	Investment	The events of August 14 show that certain equipment (*e.g.* , SCADA/EMS infrastructure) and software tools (e.g. state estimator and contingency analysis tools) are essential if operators are to make the right real-time operating decisions. Appropriate infrastructure decisions can be made only once the first two elements are addressed.	Gordon van Welie	ISO New England Inc.
12/4/2003	Structure of the Market	Establishment of appropriate operational structures throughout the U.S. and Canada not only will improve reliable power grid operations, but it will also provide a necessary foundation to ensure successful wholesale power markets. Markets implemented without a robust operational structure in place can result in unforeseen adverse reliability consequences and market manipulation. Examples of these consequences can be seen in the events in California during Winter 2001	Gordon van Welie	ISO New England Inc.
12/4/2003	Investment	What the events of August 14 bring to the fore, and what must be further investigated, are the tradeoffs among size, complexity and operational risk when considering the scope of control of any operating entity. In emergency conditions, we must rely on human operators to make decisions in a matter of minutes and seconds based on their experience and supported by adequate software tools. We must have an operating scope of control that is well within the operators' comprehension and ability to act in a timely manner.	Gordon van Welie	ISO New England Inc.
12/4/2003	Reliability Standards	As important as it is to understand the causal relationships among the various events on August 14th, it is equally important to address the underlying structural arrangements governing the operating relationship between power grid operators and facility owners - particularly in the Midwest. The Phase I Report notes these structural issues on page 11, where the Task Force observes that the institutional arrangements for reliability in the Midwest are much more complex than they are in the Northeast.	Gordon van Welie	ISO New England Inc.
12/4/2003	Legislation	ISO-NE's recommendations to Congress included: Establishment of uniform, mandatory national reliability and operating procedures that are enforceable with penalties for non-compliance; and Creation of regional transmission organizations (the "Operators") that have clear operational responsibilities and authority over regional transmission bulk systems and are based on an effective structural model for reliable management of the bulk power system.	Gordon van Welie	ISO New England Inc.

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/4/2003	Grid Integration	My concern is that the grid (particularly the Eastern Interconnection) has matured in ways that have led to an inherent loss of reliability, and that this has gone unnoticed. The most critical problem is that today's criteria, based on experience over many years, does not reflect the risks inherent in today's grid. That is, the grid has changed more quickly than the criteria (there is an inherent and long time constant in criteria development).	Harrison Clark	Harison K. Clark
12/17/2003	Grid Integration	Attached is a draft of my comments on the 8/14 Interim Report. My concern is that the grid (particularly the Eastern Interconnection) has matured in ways that have led to an inherent loss of reliability, and that this has gone unnoticed. The most critical problem is that today's criteria, based on experience over many years, does not reflect the risks inherent in today's grid. That is, the grid has changed more quickly than the criteria (there is an inherent and long time constant in criteria development). I may have time to develop my thoughts further before your deadline. How should I handle updates to my submission? Should I send an update under the same file name plus the word "update" and with additions or changes marked? When is your cut-off for comments? If there are particular areas that you would like me to expand upon, please let me know.	Harrison K Clark	Personal comment
12/22/2003	VAR/TECH	I would like to second the Dec 10 comments of Prof Canizares on the role of voltage stability and collapse on 8/14. I too am concerned that the Interim Report did not do justice to the role that reactive power and voltage played in the 8/14 event, and thereby failed to see some low hanging fruit when it comes to improving grid reliability. The Report also recognizes that reactive shortage and low voltage was a byproduct of the overload cascading and worsened the system condition and moved it more quickly toward a blackout. However, if this reactive	Harrison K Clark	Personal comment
12/10/2003	VAR/TECH	I endorse undervoltage load shedding and OLTC tap blocking as outlined by Prof Canivares. I first recommended UVLS to a client in 1975, and recommended OLTC tap blocking not long thereafter. A caveat is in order however. OLTC tap blocking is not useful on industrial loads where it can reduce the output of shunt capacitors in industrial plants without reducing the MW load at all. Even where OLTC can curtail load by reducing voltage on customers, the benefit is largely only a delay in the restoration of load since much customer load adjusts to the the low voltage and returns to it's original demand over a 15 to 20 minute period.	Harrison K Clark	Personal comment
12/10/2003	VAR/TECH	I was disturbed to read MAACs assessment of undervoltage load shedding in the MAAC Outage Review Team December 16, 2003 presentation at the NERC meeting in Philadelphia. The several close calls of July, 1999 alone should justify UVLS in MAAC as should a look at the progression of events on 8/14 in Ohio. The expressed concern with inadvertent tripping (slide 22) is unfounded. UVLS has been in use in enough systems for enough time to demonstrate its reliability and effectiveness. The finding that hi-speed static var control will _significantly reduce the amount of_ UVLS needed is also questionable. The reactive problem arises only after all such devices are at maximum output rendering them no different from switched shunt capacitor bank in terms of voltage instability.	Harrison K Clark	Personal comment

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/10/2003	VAR/TECH	Finally, the Interim Report contains several references to generators tripping when driven by voltage regulators to maximum reactive output. Carson Taylor and others have addressed this issue so I will be brief. No properly equipped generator with functioning excitation controls should trip as a result of high reactive demand.	Harrison K Clark	Personal comment
12/14/2003	Editorial Comment	However, I felt that the Interim Report should have been more aggressive in identifying conditions in today's grids that degrade reliability. I believe that a thorough examination of 8/14 and previous events and near misses would have identified conditions that played a role in 8/14 and others that didn't, and that portend a bleak future for reliability. These conditions are the subject of my comments.	Harrison K Clark	Personal comment
12/14/2003	System Operations	Solving the problems of wide-spread high loadings and difficult load characteristics will not be easy. I don't profess to have all the answers, but the following thoughts come to mind.	Harrison K Clark	Personal comment
12/14/2003	Standards Development	Enforcement of present criteria will help little. Adding transmission may not help. Only if transmission is added to reduce loadings will it improve reliability. Latent failures and sag limits demand attention. New technologies such as FACTS may reduce already thin margins as well as further complicate an already too complex system and lead to more complex behavior that can befuddle operators. Today's criteria are based on experience that predates today's grid and are in need of a major overhaul. New technologies such as FACTS may reduce already thin margins as well as further complicate an already too complex system and lead to more complex behavior that can befuddle operators. Protection to deal with cascading simply does not exist and is not on the horizon.	Harrison K Clark	Personal comment
12/14/2003	Technical Operating Procedures	Segmentation of the AC grid by HVDC (back-to-back and line conversions) has been discussed since the early 80's and its time may have come. It would solve some of the consequences of higher grid loading and greatly increase transfer capability. The operations paradigm needs a major overhaul. Undervoltage load shedding is woefully underutilized though it has been an inexpensive and known technology for 25 years. Maximum Credible Disturbances (MCDs) and Possible but Improbable (PBIs) events need much more attention.	Harrison K Clark	Personal comment
12/14/2003	Grid Integration	The natural maturation of the grid has resulted in an erosion of reliability. This problem needs attention. The effort should start with a rigorous assessment of reliability over the last 20 years to quantify and characterize the developing weaknesses. Then cost effective solutions to those weaknesses should be developed and criteria should be adjusted to ensure those new solutions as well as traditional solutions are applied sufficiently to ensure a reasonable level of reliability.	Harrison K Clark	Personal comment

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/14/2003	Editorial Comment	Solutions should be part of a plan to improve reliability in the near term and not an R&D agenda for application in 20 years.	Harrison K Clark	Personal comment
12/5/2003	Safety Net	We would like to see the Joint Taskforce analyze and fully report on what happened in those adjacent areas, what automatic load shedding was in place and whether it properly operated in those areas, and what needs to be done to mitigate a future recurrence of similar events.	Howard A. Tarler, P.E.	New York State Department of Public Service
12/5/2003	Editorial Comment	We would also respectfully request that the taskforce provide further explain its conclusion (on page 51) that New York was "aided by generation in southern Ontario that split and stayed with western New York." Ontario is an important economic partner for New York State, particularly western New York, and it is critical that the Task Force's Final Report identify and explain anything unique about the interconnections between Ontario and New York that might prove beneficial to that partnership in the future or that might prove valuable as we examine the regional interconnections among states.	Howard A. Tarler, P.E.	New York State Department of Public Service
12/5/2003	Grid Integration	It is important to note that the split referenced in the report preceded, and quite possibly contributed to the tripping of several large nuclear units in western New York. As a result, it is not clear to us whether this split may have affected our grid's ability to with stand the cascade, keep New York generators operating, or if it affected our ability to restore load due to the significant time it takes to re-start nuclear units. This analysis will be an important ingredient into any recommendations that will be made in your Phase 2 report.	Howard A. Tarler, P.E.	New York State Department of Public Service
12/5/2003	System Operations	We do not believe that you can continue the process into the Phase 2 recommendations until you have fully considered the reasons for, and the impacts of, the transmission system events in New Jersey, Pennsylvania, Ontario, Connecticut, and Massachusetts.	Howard A. Tarler, P.E.	New York State Department of Public Service
12/5/2003	Training	Your report concludes that the blackout was initiated in Ohio and identifies six violations of reliability criteria associated with those events. Clearly steps need to be taken to ensure that reliability coordinators and control area operators are better prepared and better motivated to follow reliability rules.	Howard A. Tarler, P.E.	New York State Department of Public Service
12/5/2003	Editorial Comment	But, as well done as the interim report is, it is obviously not yet complete. In the report's own words: "The first phase was to focus on what caused the outage and why it was not contained…." There is still work left to be done to analyze the events in the areas immediately adjacent to New York, so that we here in New York can better understand why the New York system was so severely impacted.	Howard A. Tarler, P.E.	New York State Department of Public Service

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/5/2003	System Operations	There are also references in the report that in aggregate seem to suggest that New York might not have been able to survive the system separation from PJM and New England because it was a heavy importer of power. Our information is that aside from the normally occurring import of power from Quebec, which continued during and after the event, very small and operationally insignificant amounts of power were being imported into New York State. These facts, if confirmed by your team, in conjunction with the information and analysis we have requested about the events in Connecticut, New Jersey, and Ontario, may present a clearer picture of what happened to the electric system in New York.	Howard A. Tarler, P.E.	New York State Department of Public Service
12/5/2003	Editorial Comment	The interim report notes that you have performed a “detailed examination of thousands of individual relay trips for transmission and generation events” (p. 103) but the details are not present in the report. We are very interested in knowing the detailed relay information you reviewed and the results of the technical analyses you performed concerning the opening of the transmission lines surrounding New York. That includes not only the tie lines to New York, but also the detailed information about the internal line openings in New Jersey and Connecticut when those systems came apart and were left hanging onto the New York control area.	Howard A. Tarler, P.E.	New York State Department of Public Service
12/5/2003	Editorial Comment	We think it is an excellent starting point, but it should only serve as a starting point. We feel strongly that additional analysis is essential to better understand the impact that neighboring systems had on New York's grid. We are not interested in placing blame on these systems, simply to better understand how events occurring on these systems helped or hampered our system and its recovery, and working with you to develop recommendations that improve the reliability of the interconnected grid.	Howard A. Tarler, P.E.	New York State Department of Public Service
12/5/2003	Emergency plans	We would respectfully request that the Joint Taskforce investigate and report on what the impact was of loads in Northern New Jersey and Southwest Connecticut being isolated onto the New York City and Long Island areas. The findings presented to date do not answer the question as to whether New York City and Long Island would have totally blacked out from the events occurring in Ohio and Michigan had these added loads not been borne by the New York City and Long Island systems, or what role, if any, the adjacent external loads played in pulling down the New York City and Long Island systems.	Howard A. Tarler, P.E. on behalf of Chairman William M. Flynn	New York State Department of Public Service
12/7/2003	OTHER	A very interesting report.	J SPEARS	none given
1/12/2004	OTHER	The purpose of the Best Real-time Reliability Analysis Practices Task Force (BRRAPTF) is to identify the best practices currently employed for building and maintaining real-time network models and for performing state estimation and real-time contingency analysis. The ultimate goal of the task force will be to recommend specific, auditable requirements for inclusion in new reliability standards for real-time network modeling and security analysis. Document specifies other goals and governing authority. http://electricity.doe.gov/govforums/documents/comments/010704_0002.pdf	Jack Kerr	Best Real-time Reliability Analysis Practices Task Force (BRRAPTF)
1/7/2004	Reliability Standards	NERC should develop detailed, uniform standards defining the criteria by which adequate real-time models are built, the criteria by which adequate observability is defined, and the criteria by which state estimator and contingency analysis performance and solution quality are measured.	Jack Kerr	Dominion Virginia Power

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/7/2004	Reliability Standards	Standards for the maintenance and support of the models and tools are also needed. All of these new standards should be derived from an analysis of existing best practices and must be uniformly applied. There should be compliance audits and sanctions associated with these standards.	Jack Kerr	Dominion Virginia Power
1/7/2004	Reliability Standards	A NERC working group with a power system engineering perspective should be established to promulgate these standards (see attached scope of a proposed task force). The existing Data Exchange Working Group (which seems to have more of an IT perspective) should work closely with this new group.	Jack Kerr	Dominion Virginia Power
1/7/2004	Training	Prior to a Control Area or other entity leaving the footprint of one Reliability Coordinator and joining the footprint of another, a transition plan should be developed and submitted for the review and approval of the NERC Operating Reliability Subcommittee. The transition plan is above and beyond the scope of the revised Regional Reliability Plan in that it is an interim plan	Jack Kerr	Dominion Virginia Power
1/7/2004	Investment	Consideration should be given to the development of new reliability tools for Reliability Coordinators. For example, an overview of the real-time voltage profile of the entire interconnection based on per unit voltage (voltage contours) and also having views of recent trends would be very useful to detect patterns of voltage degradation. Also, methods and tools are needed to identify and study (in real-time) plausible, potentially harmful second and third contingencies that could lead to cascading following the loss of a key facility. You could call this a situational multiple contingency analysis conditioned on the identification of a harmful first contingency.	Jack Kerr	Dominion Virginia Power
1/7/2004	Training	Operators should be provided the necessary training to acquire the skill sets and confidence they need to exercise their authority to take drastic action in an emergency situation. Their management must be willing to support and reward the exercise of this authority.	Jack Kerr	Dominion Virginia Power
1/7/2004	Reliability Standards	The regulatory reporting burden following load shed must be minimized. Operating agreements must be in place that, in the context of regulatory oversight, recognize the responsibilities of the asset owners for reliability yet obligate the asset owners to follow the directives of the Reliability Coordinator in a declared emergency in order to fulfill those responsibilities.	Jack Kerr	Dominion Virginia Power
1/7/2004	Reliability Standards	Standards are needed to impose requirements on Load Serving Entities to implement automated, SCADA- based load shedding schemes. These schemes should be designed to provide the rapid identification of blocks of load based on location and MW quantity. Such schemes are necessary to allow a timely and effective response to a directive from a Reliability Coordinator to shed load. It is not acceptable to dispatch servicemen to a substation in response to such a directive.	Jack Kerr	Dominion Virginia Power

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/7/2004	Emergency plans	NERC should develop a pro forma re-dispatch agreement. Re-dispatch across Control Area Uniform practices need to be developed for efficient and professional protocols for telephone communications during an emergency. These practices need to focus on common terminology, proper identification of call participants, documentation of who said what and when, and logical problem solving processes leading to problem resolution and avoiding traps such as "group-think". Consideration should be given to implementing text message broadcasting systems based on voice recognition and transcription rather than relying on manually typed alphanumeric characters.	Jack Kerr	Dominion Virginia Power
1/7/2004	Resource Planning	Transmission line ratings should be stated in Amperes instead of MVA in order to eliminate the disconnect between the actual voltage component of the MVA measurement and the nominal voltage component of the MVA rating.	Jack Kerr	Dominion Virginia Power
1/7/2004	Resource Planning	The NERC Planning Standards should probably be amended to include another category of contingencies more severe than those listed in categories B, C, and D in Table 1. Interregional studies should be done to evaluate the inter-regional impact of these more severe contingencies such as loss of a major station and every line connected to the station, loss of multiple lines feeding large load centers, and the loss of major interfaces or transfer paths. Inter-regional contingency plans should be developed to address an inter-regional response to the operational problems identified in the study results.	Jack Kerr	Dominion Virginia Power
1/12/2004	Prevention	International Transmission recommends that the Task Force address the following recommendations: 1)Re-examine operating schemes, particularly complicated ones, and weigh not only the risk of a particular event but the possibility of human error. 2)Re-examine planning criteria. Planning criteria that prepare a system or control area for a single contingency have become economically unacceptable, particularly where the system or control area depends upon various operating schemes to ensure reliability. The utilities and regulators should reevaluate the use of single contingency planning criteria. The industry and its regulators should adopt more stringent standards such as those now used by the Northeast Power Coordinating Council (NPCC") for utilities operating in the northeast and apply them to the entire continent.	James L. Blasiak	DykemaGossett PLLC for International Transmission company (ITC)
1/12/2004	Standards development	Review the standards that are set to justify new transmission projects and make them mandatory. Once minimum standards are set they can easily be interpreted to dictate the maximum capability that a utility can install because utilities are under increased pressure to watch their "bottom line." Also, from a regulatory perspective, utilities are reluctant to construct to a higher-than-minimum standard because any additional investment may be viewed by regulators as 'gold plating," subject to elimination from rate base as unnecessary and "imprudent" investment. In particular, regulators and utilities must consider making the necessary investments to install separation control devices on the grid to eliminate the one negative aspect of grid integration, the possibility of cascading failure. As we saw on August 14, the northeast power grid has become so inextricably connected that one event on one circuit of one utility can cause a cascading failure affecting 50 million people. If other grid additions are not possible in a timely fashion, the installation of separation control devices at	James L. Blasiak	ITC

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/12/2004	Investment	As an independent entity, International Transmission has an incentive to invest in transmission facilities because it is our only business. Other entities have other incentives and they will not necessarily act in a way that improves the infrastructure. For example, a combined utility serving a load pocket will not have the incentive to build new transmission facilities to eliminate the load pocket if it is profiting from the generation shortage in the pocket. The formation and empowerment of independent transmission companies is thus sound public policy.	James L. Blasiak	ITC
1/12/2004	Structure of the Market	Nothing in these recommendations should be interpreted to suggest that the ongoing transformation of the nation to an unbundled, open access power market should be deferred. Regulators should give transmission providers adequate time to phase in any new standards adopted as a result of the final Task Force Report to ensure that nothing adopted in response to the events of August 14 negatively affects open access initiatives. Over the long-term, if the industry successfully increases the carrying capacity of the transmission grid, it will help implement the FERC's open access initiatives by providing more capacity for unbundled transactions. Also, the reinforcement of the grid will assist the industry in that a more robust system would be less susceptible to terrorist attacks and would allow for quicker recovery should an attack occur.	James L. Blasiak	ITC
1/12/2004	System Operations	Re-examine all operating schemes requiring automatic or manual controls to keep equipment or the system from exceeding limits (e.g., voltage). The examination should compare the total cost of outages (including the risk cost of blackouts) to the cost of transmission system upgrades. Different criteria would have to be determined for each of the operating schemes that are currently in use and stricter criteria would have to be adopted in the event that seams agreements rely on load shedding schemes on the day of service to match nominations with available capacity: Use of "emergency" short-time ratings.	James L. Blasiak	ITC
1/12/2004	System Operations	Manual schemes-manual schemes that are dependent on load shedding would have to incorporate in the analysis the full cost to the market resulting from the interruption of electrical supply.	James L. Blasiak	ITC
1/12/2004	Emergency plans	Automatic schemes (e.g., relay initiated). Automatic schemes that trip generation plants to save the transmission system would have to be evaluated against the cost of adding more transmission capacity. In this evaluation, all of the costs of the choice would have to be balanced, including the costs associated with the risks that the relay scheme imposes on the market and the grid over the long term.	James L. Blasiak	ITC
1/12/2004	Prevention	Reexamine planning criteria. Specifically, where transmission facilities have been designed to withstand the failure of one element or one contingency (N-i), the planning criteria should be revised so that the transmission system would withstand multiple events. In most cases, this minimally acceptable criteria should allow the grid to continue to operate even if both a major transmission facility (T-i) and a critical generation station (G-i) were out of service simultaneously.	James L. Blasiak	ITC

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/12/2004	Standards development	Conservative criteria, such as those employed currently by the Northeast Power Coordinating Council (“NPCC”), should be adopted. NPCC criteria, for example, are stricter than those employed by the East Central Area Reliability Council (“ECAR”). ECAR and the North American Electric Reliability Council (NERC”) both give the transmission owner/operator the discretion to build transmission facilities to meet the higher, multi-element outage standard and do not require the transmission operator to adopt the higher standard. To eliminate the financial and regulatory disincentives that now discourage transmission operators from adopting stricter standards on a voluntary basis, regulators should make stricter planning standards mandatory.	James L. Blasiak	ITC
1/12/2004	Prevention	Where appropriate, system separation devices should be considered as a method of stopping the spread of a cascading outage.	James L. Blasiak	ITC
1/12/2004	Market and deregulation	Utilities that operate in both the merchant and transmission markets should be carefully supervised by regulators to ensure that they allocate adequate funds to support their transmission businesses. Stricter standards must be phased in to ensure: that planners have time to adequately design and budget for transmission system upgrades, and that they would not needlessly decrease available transmission capacity for use by open access market participants.	James L. Blasiak	ITC
1/12/2004	Structure of the Market	Over the long-term, stricter planning standards can be justified, in part, on the basis that additional transmission capacity will be made available for the growth of the unbundled, open access electricity market and that readily controlled hard-wire reserve capacity will be available in the event that the industry needs to respond to a terrorist attack or other emergency affecting the electricity infrastructure.	James L. Blasiak	ITC
1/12/2004	Structure of the Market	The final report should indicate that condemnation proceedings based on federal authority may be needed to site new transmission facilities. The continued growth of the unbundled interstate electricity market may well depend on it.	James L. Blasiak	ITC
12/18/2003	System Operations	Also its must be noted that telecommunications companies world wide now start the introduction of voice over IP based service, thus starting the dismantling and replacement of the old telephone system. The important observation is that future reliable telecommunication will highly depend on the availability of public power supply as local backup power from batteries and fuel powered generators is not sufficient nor possible at a large scale due to cost, endurance, maintenance and operational difficulties. As a consequence there will be a need for public high-grade electricity. We suggest a cost-effective solution with islands of premium power networks capable of delivering electricity of extra high availability with integrated public backup power. These networks could preferably at the same time be co-installed and co-located with optical fibre networks, MAN (Metropolitan Area broadband Networks). Hybrid cables are available, please see attachment.	John Akerlund	Uninterruptible Power Networks UPN AB

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/8/2003	Editorial Comment	Clearly the loss of FE's Sammis-Star 345-kV line and the underlying 138-kV system was the last straw (inflection point or trigger) in the sequences that lead to the cascading effect, but it is misleading to eliminate the prior outages as having contributed to the cascading effect. While an interesting academic exercise, pinpointing the event that triggered the cascading outages, it does not address the underlying issues. After all, most of the prior outages that occurred on August 14, 20003 did in some way contribute to the cascading blackout.	John Synesiou	IMS Corporation
12/8/2003	Editorial Comment	The report's explanation of the events after loss of Sammis 345KV line fails to explain the reasons for the cascading blackout. The report is deficient in this area and should be expanded to explain why the generator protection tripped before the load was disconnected, after this situation was described as a typical line overloaded condition. Without further data, it is difficult to determine why protection operated in this way.	John Synesiou	IMS Corporation
12/8/2003	Emergency plans	What is clear from the report is that operators lacked necessary information to operate effectively and that there was also poor co-ordination between control centers. This lack of information prohibited the operators from taking the necessary steps that would have prevented the blackout. Evident from the report is that SCADA systems can and do fail at the most inappropriate time. It is therefore imperative that complimentary and redundant data be available to validate and verify SCADA data.	John Synesiou	IMS Corporation
12/8/2003	Grid Integration	It is well known that long interconnected AC transmission lines have a propensity to be unstable. Although this is premature, I would recommend that DC line interconnects be considered which will make the grid far more robust and far less susceptible to these types of cascading failures.	John Synesiou	IMS Corporation
12/8/2003	Reliability Standards	An attempt to mandate operational standards will not prevent events like this from occurring in the future. Standards are important of course, but as state above, to have accurate information and co-ordination between interconnected utilities is far more important.	John Synesiou	IMS Corporation
12/8/2003	System Operations	SCADA/EMS operations people and regional operators must be fully informed about the conditions of the network under their control. They must also have the means to quickly balance supply and demand without large-scale instantaneous interruptions of supply or demand that cause instability in adjacent networks.	John Synesiou	IMS Corporation
12/8/2003	Investment	Technology exists today that provides fast load reduction by disconnecting known demand on the distribution network, sequenced to drop demand without impacting the remaining system. This solution is fast and eliminates the need to operate high voltage breakers, and significantly reduces required breaker maintenance. Load reduction can initially target non essential load, thus limiting power disruptions to customers. This technology can target more than 90% of the customer load, whereas breakers typically target less than 60% of the load because of collocation of essential services. This low cost technology exists for the DMS and sub DMS networks that will solve most of the problems that were the true source of the blackout.This technology improves energy efficiency (between 15% and 30%), extends network visibility to DMS and sub DMS networks, identifies single point of failure, implements energy audits, multi-tariff metering, real-time pricing, open access energy accounting, etc.	John Synesiou	IMS Corporation

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/7/2003	Market and Deregulation	First Energy has changed from a utility company that put its customers first and had concerns about the local community, to a management group whose only concern is "the bottom line" on a quarterly basis. Deregulation is one of the culprits that has spawned this new utility entity of First Energy that has messed up its nuclear activities at the Davis-Besse plant, that has failed to participate in a proper effort at a transmission system, and that could not even keep its trees properly trimmed beneath the huge transmission lines that it uses.	Joseph Meissner	Personal comment
12/7/2003	Editorial Comment	Let me be direct. Your recent hearings here in Cleveland were a sham. Hardly any notice was provided to the public. Furthermore, the time of the announcement which was about a week before the hearings took place, was equivalent to virtually no notice at all. It normally takes community groups from thirty to sixty days to respond to any call for hearings and public comments. These community groups lack the millions of dollars that governmental agencies like yours have at their command. You are allegedly public servants whose mission it is to protect the citizenry. You have failed in that mission by the hearings you held in Cleveland. Call for further hearings in Ohio and provide adequate notice to the citizenry and community groups. This means at least 30 to 60 days of notice at times and places at which the public is available, including keeping the hearing open until 7pm for those who work late.	Joseph Meissner	Personal comment
12/7/2003	Editorial Comment	Our client groups echo Attorney Gruber's concerns about First Energy and the PUCO. The PUCO has proven itself incapable of protecting electric customers, whether here in Ohio or elsewhere in the nation. You had better prepare for further blackouts including the possibility these could take place in the middle of winter at night when snow and ice cover every line, every street, and every building, rather than on a warm summer's day when people, including utility work crews, could respond to the emergency. I should point out that people's furnaces depend upon electricity to operate. So you had better prepare for millions of people needing food, shelter, and warmth.	Joseph Meissner	Personal comment
12/5/2003	Editorial Comment	I am concerned about shortcoming in the engineering profession regarding its collective responsibility for workplace and public health and safety in engineering systems as manned space flight, power grids, nuclear power and technology, among others. The Interim Report: Causes of the August 14th Blackout in the United States and Canada is silent to my concerns. I believe my concerns are relevant to the U.S.-Canada Power System Outage Task Force and merited treatment in the Interim Report. In fact, given the "strict honor code" implementation basis of engineering ethics, the failure of the engineers on the Task Force to explicitly evaluate possible shortcoming in the professional competency and ethics of engineers involved with the outage is, in my professional opinion, professionally blameworthy.	Joseph P. Carson, P.E.	Personal comment

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/12/2004	Reliability Standards	Statements that mandatory compliance to NERC standards will somehow ensure total reliability pre-supposes that every one of the NERC Standards will be perfect in every way and will result in eliminating blackouts in the future. Even with the best of intentions of all parties concerned in the business, random outages or mis-operations will occur in large interconnections in stressed systems. Accompanied by human error and judgment, computer software and hardware glitches, system modeling tools and data for simulation that are not perfect, simulations that cover only parts but not the entire Interconnection, or imprecise generalized criteria, it is probable that these could culminate in a sequence of events with disastrous consequences. While the probability is low, recognized areas of weakness must be eliminated or minimized.	Les Pereira P.E.	Personal comment
1/12/2004	Structure of the Market	We need to examine the new area of interaction between the new market areas and reliability coordination. Deliberate acts of sabotage rather than random outages that threaten security create an added dimension to the problem.	Les Pereira P.E.	Personal comment
1/12/2004	Structure of the Market	The advantages of the new market areas from a reliability perspective are that state estimators run every 5 minutes on real-time. Security-constrained programs imply that they attempt to contain system over-loads (or congestion) by dispatching generators that simultaneously provide system MW balance economically. The SCOPF theoretically takes the next (N-1) outage in its determinations for optimum dispatch.	Les Pereira P.E.	Personal comment
1/12/2004	Structure of the Market	The disadvantages of the new market areas from a reliability perspective are: a)The “islanded” nature of the isolated market system imposes inherent limitations for achieving the optimum dispatch from an overall Interconnection standpoint; b)The next critical outage may well be in the neighboring systems – or two systems away - and not internally; c) Outages of critical EHV lines may not provide an OPF solution convergence; d) The “optimum” economic dispatch could well take the dispatched unit to its MW and MVAR “limits” allowing no margin for dynamic responses during MW and MVAR excursions critical to contain collapses; e) Other concurrent market system mechanisms for ancillary systems, including MVAR support, spinning reserves, regulation etc are necessarily disjointed in relation to, and in comparison to, the self-contained and automatic LMP computation algorithm for SCED and SCOPF that deals primarily with mitigation of overloads and economic dispatch; f) LMP systems of the DC type additionally inherently suffer from their inability to model reactive MVAR AC power in a collapse situation. In the AC OPF programs, the non-linear generator capability curves are inadequately modeled.	Les Pereira P.E.	Personal comment
1/12/2004	System Operations	Given the clear dominance of the market system in the 5 minute-to-5 minute, hour-to hour operation of the power system, there could be a reluctance of the reliability coordinator to intervene until the distress signals are too obvious to ignore. Premature intervention can be costly. If the two functions are carried out by the same entity, a conflict could well result in real-time operation. Economics and reliability do not mix very well. Many of these issues do not appear to have been discussed in the Aug.14th blackout report. It is felt that recognition and acceptance of all issues that impact reliability are the important first steps. Solutions will follow once that is done.	Les Pereira P.E.	Personal comment

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/12/2004	Comment	My PowerPoint slide presentation from the Technical Conference held at Toronto on January 9th 2004 in the Breakout Section on Planning, Design and Maintenance Tools can be seen on pages 5-7 at http://electricity.doe.gov//govforums/documents/comments/R1-Comments_by_Les_Pereira_on_the_Interim_Report-Aug_14th_blackout.pdf	Les Pereira P.E.	Personal comment
1/14/2004	Reliability Standards	The contribution that a reliable energy storage device can make to grid reliability has been recognized by the industry for some time. Simply put, energy storage provides a buffer on the grid, matching generation and demand during interruptions. The concepts presented in this paper would provide quantum improvements to grid stability by offering fundamental changes with new technology. Based on other energy systems that incorporate storage, there is a very good reason to expect significant performance improvement using energy storage in the grid. Until now, there has not been a utility-scale energy storage device at high enough power levels with sub-cycle response to make a difference in the T&D system and have a 20 year life. A flywheel based energy storage system (FESS) is such a device and offers unique solutions to grid reliability and performance problems.	Matthew L. Lazarewicz	Beacon Power Corp.
1/14/2004	Reliability Standards	FESS-based applications and solutions can make a significant contribution to grid system stability and reliability by: 1)Delivering much faster responding frequency regulation 2)Providing effective, targeted congestion relief capability 3)Increasing margins on lines (remove the need to derate lines to accommodate angular instability limits) 4)Alleviating thermal limit constraints 5)Attacking angular instability at the root (real power to provide stability) 6)Deferring investment by providing short term congestion relief in critical locations.	Matthew L. Lazarewicz	Beacon Power Corp.
1/14/2004	Editorial comment	One of the major outcomes of the Interim Report is the recognition that there may be a high value in improving grid performance, reliability and stability without regard for current measures for financial return. The Interim Report does not present guidelines how to measure or monetize improvement, but points out the need for introducing technologies to improve grid reliability in a deregulated environment.	Matthew L. Lazarewicz	Beacon Power Corp.
1/14/2004	Grid Intergration	Angular stability, however, is a problem that does not have a satisfactory solution today. Angular instability is the result of slight frequency differences between the generator and transmission system. The result of the generator “hunting” for the right speed to match the load is a low frequency, undamped oscillation that travels through the transmission line. That low frequency power can be quite high and actually cut into contingency margins. The only way to damp this oscillation is with fast responding real power. Such oscillations apparently were present before the August 14th blackout, and are troublesome in California today. A FESS would be ideal in damping these types of oscillations. This bonus benefit is inherently available while at the same time providing frequency control.	Matthew L. Lazarewicz	Beacon Power Corp.

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/14/2004	Grid Intergration	By contributing underfrequency protection in real time, FESS can prevent premature tripping of generators and transmission lines. FESS can act as a buffer and break in the system. FESS are ideally suited to absorb any system “bumps” in voltage or frequency. FESS can contribute to substantial balance in the system, having a disproportionately positive effect on overall grid operations. FESS mitigate frequency anomalies and can substantially “even out” or smooth frequency fluctuations, thus contributing to grid stability.	Matthew L. Lazarewicz	Beacon Power Corp.
12/11/2003	Comment	Recently I have completed a report in regards to the blackout of August 14", which proves the blackout was likely part of a multi-faceted military test. As a citizen I am very concerned about this. My report is included in this package for your review, and must be reviewed if we are ever to know what really happened on August 14", 2003. http://electricity.doe.gov/govforums/documents/comments/111903_0001.pdf	Michael Kane	Personal comment
1/15/2004	System Operations	We have reviewed the report & many but not all of the findings agree with our observations and of the separation observations of the MPSC. The problems occur in the section discussing events after 16:06. In particular, some of the data which ITC has supplied appears not to have been incorporated, notwithstanding our supply of such data at the earliest date. It is especially important that flow information be utilized where available. Such flow data is available & was provided for Michigan systems. Power flows occur in accordance with certain fundamental electrical laws such as Kirchov’s Current Law which renders them cohesive where other data may be disjointed. Notwithstanding the above, the report seems to indicate that the power surge was in reaction to Michigan units going offline, when those events clearly occurred following the power swing.	none given	ITC
1/15/2004	System Operations	The report also says that there was no voltage collapse-we saw voltages of 23% on our system prior to the trip of the cross-state ties. I make these remarks because of an overwhelming conviction that a problem will not be solved unless the problem is completely & accurately understood. An inaccurate understanding will leave the potential of future problems.	none given	ITC
11/3/2003	VAR	The interim report primarily blames First Energy for causing the August 14 blackout, and CNP concurs with that assessment based upon the information presented in the interim report. however, in reviewing the report, CNP noted two areas of discussion that may need to be re-examined including: a) It is unclear that First Energy alone was responsible for restoring the system to a secure state after the Harding – Chamberlin line outage; and b) The summary dismissal of generator reactive performance as a contributing factor on page 18 of the interim report is inappropriate. Also, it was unclear when the comments were due. http://electricity.doe.gov/govforums/documents/comments/Aug14ReportComment_CNP.pdf	Paul X. Rocha	CenterPoint Energy

Date	Rec Type	Recommendations/ Comments	Name	Organization
11/16/2003	Inquiry	I am from the French Grid Operator, RTE, and I was very interested by your Interim Report. But I would have appreciated more information about these topics: The system restoration isn't studied at all, but as it was very long (up to 50 hours) it would be very interesting to analyze it and perhaps implement corrective action to reduce its length; The report tells that some generation groups lost synchronism, but information is not very complete (number of groups, perturbation...).	Philippe Carpentier	French Grid Operator
1/12/2003	Safety Net	A group of industry experts, who are experienced at calling and observing the existing Transmission Loading Relief (TLR) process, should be convened and instructed to design a process that could be implemented in the shortest time. http://electricity.doe.gov/govforums/documents/comments/ITC_operating_comments.pdf	Raymond K. Kershaw	International Transmission Company
1/12/2003	Prevention	A design philosophy to be employed will be to emphasize speed and reliability at the expense of tariff restrictions that currently impede the TLR process. While the current TLR process recognizes two system states “secure” and “security limit violation” (levels 3B, 5B, 6), both are fraught with prescriptive tariff based instructions which are going to slow down the process. http://electricity.doe.gov/govforums/documents/comments/ITC_operating_comments.pdf	Raymond K. Kershaw	International Transmission Company
1/12/2003	Structure of the Market	Tariff restrictions and other commercially sensitive impositions can be placed on TLRs which are called *in advance of and needed to prevent* insecure states. An example of when this shouldn’t be allowed would be when an insecure state was expected within the next 30 minutes through load increase or other expected condition. http://electricity.doe.gov/govforums/documents/comments/ITC_operating_comments.pdf	Raymond K. Kershaw	International Transmission Company
1/12/2003	Resource Planning	We believe that whenever the system has a “security limit violation” or is one contingency away from one (current levels 3B,5B, & 6), reliability considerations should be pre-eminent. Reading the current NERC Policy 9 you still get the impression that tariff market issues are guidelines for the Reliability Coordinator. It’s not surprising that the process is slow. We recommend that levels 3B, 5B and 6 be rolled into one procedure with no tariff restrictions. Speed should prevail over tariff.	Raymond K. Kershaw	International Transmission Company
1/12/2003	Emergency plans	Being one contingency away from a “security limit violation” is not all that rare of an occurrence, reliability considerations must prevail over tariff. NERC Policy 2 requires a return to a “secure” state within 30 minutes so the TLR process should be designed to operate in less than 30 minutes. This won’t be easy and may require operating to a more severe criteria in some cases. http://electricity.doe.gov/govforums/documents/comments/ITC_operating_comments.pdf	Raymond K. Kershaw	International Transmission Company

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/12/2003	System Operations	We recommend that a very simple approach be taken which eliminates some latitude that Reliability Coordinators now have in picking a TLR level. a)Determine the Relief Needed b) Enter the Relief in the IDC and let the IDC tell the RC the TLR level needed. Levels 1, 2, 3A, 4 & 5A with prescriptive tariff restrictions are only allowed if there is no security limit violation & you're not one contingency away from one c)Call the TLR at an appropriately high enough level as indicated by the IDC d) If a TLR is called on a particular flowgate and it fails (trips), the RC must complete the TLR and consult the IDC for any necessary increase in MW relief. This is true whether or not the next flowgate which may be in security limit violation is under his authority. http://electricity.doe.gov/govforums/documents/comments/ITC_operating_comments.pdf	Raymond K. Kershaw	International Transmission Company
1/12/2003	Structure of the Market	Reliability Coordinator authority has specific geographic or equipment boundaries as currently written in NERC policies. In order to avoid delays in implementation of TLR, these boundary areas need to be overlapped such that more than one RC could implement a TLR in a boundary area.	Raymond K. Kershaw	International Transmission Company
1/12/2003	Structure of the Market	There has been some discussion about expanding RC area size which would, in effect, reduce the number of RC areas in the Eastern Interconnection and eliminate many "seams". We think this is a good idea and that these RCs should be independent of any other entity (RTOs which run markets, control areas, etc). However, some reliability authority still needs to reside within a market or RTO under the larger reliability authority area. A "local" reliability authority still needs to function (within a market, for example) under the larger Reliability Coordinator. However, both have authority to act in the event the system is one contingency away from a security limit violation or a security limit violation exists. http://electricity.doe.gov/govforums/documents/comments/ITC_operating_comments.pdf	Raymond K. Kershaw	International Transmission Company
1/12/2003	Resource Planning	NERC Reliability Policies should be stand alone policies. Some reliability plans that we have seen have included "interpretations" of NERC policy with instructions to their Reliability Coordinators. Because these are usually "tariff" interpretations benefiting the local RTO/ISO, they should not be allowed. http://electricity.doe.gov/govforums/documents/comments/ITC_operating_comments.pdf	Raymond K. Kershaw	International Transmission Company
1/12/2003	Structure of the Market	It has been our observation that reliability coordinators have requested improvements through the NERC processes in the past.. In many cases, the now-defunct Market Interface Committee (MIC) turned them down for commercial tariff reasons. This power should be severely limited in the future. http://electricity.doe.gov/govforums/documents/comments/ITC_operating_comments.pdf	Raymond K. Kershaw	International Transmission Company
1/12/2003	Standards Development	NERC Policy 9C1C discusses TLR level 3B. There are 11 prescriptive steps associated with calling this level TLR. Most will slow down the process because operators have to follow all the steps. Since level 3B requires that you either have a security limit violation or are one step away, why would you slow the process down in this fashion?	Raymond K. Kershaw	International Transmission Company

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/12/2003	Standards Development	Policy 5B seems to say that if you're one contingency away from a security limit violation, you have to wait for all non-firm to be cut first (see 4th bullet under section 7.1 of policy 5B below) before you can cut firm. This is purely a tariff limitation which has nothing to do with reliability. We think this not only slows the whole process down but conflicts with NERC Policy 2 which says you have 30 minutes to eliminate the condition where you are one contingency away from security limit violation. This prescribes the impossible situation where you have 30 minutes to cut non-firm first and then proceed to firm cuts. TLR level 6 allows you to ignore these tariff prescriptions *if you choose to call a level 6, which didn't happen on August 14.*	Raymond K. Kershaw	International Transmission Company
1/12/2003	Standards Development	Use NERC processes to redesign the IDC such that it is more of a real-time tool. This will require budgetary backing and reductions in the time allowed for entities to provide data used by the IDC.	Raymond K. Kershaw	International Transmission Company
1/12/2003	Standards Development	Require input of actual system dispatch instead of a simulated economic dispatch in the IDC base case.	Raymond K. Kershaw	International Transmission Company
1/12/2003	System Operations	Expand the use of the Flowgate Impact Study Tool (FIST), an offshoot program of the IDC. The graphical displays provided by FIST would easily indicate to a Reliability Coordinator (RC) the effects of any TLR level.	Raymond K. Kershaw	International Transmission Company
1/12/2003	System Operations	Using an "actual" dispatch would allow the IDC to make redispatch recommendations to the RC based on "real-time" data.	Raymond K. Kershaw	International Transmission Company
1/12/2003	System Operations	Consider expanding its use to include contingency analysis independent of state-estimated solutions. Input in a timely fashion of both SDX and ISN data would allow this functionality in a "real-time" sense. Section III of this report contains Contingency Analysis suggestions.	Raymond K. Kershaw	International Transmission Company
1/12/2003	Standards Development	ITC would like to make the following recommendations regarding the IDC to supplement those of the vendor, OATI. We believe the tool needs enhancement to make it a tool capable of supporting a "real-time" TLR process. The time allowed for inputting new data or changes to existing data is too slow to support real time conditions.	Raymond K. Kershaw	International Transmission Company
1/12/2003	Standards Development	*Require that forced and unforced equipment outages be available to the IDC within 5 minutes of the actual outage (or restoration when put back in service).* Currently, this does not have to be done using "SDX" until the top of the next hour. Observed compliance is very poor in this regard. We recommend mandatory compliance with penalties for failure to comply. This is more a recommendation for SDX than the IDC tool itself but it has obvious IDC implications.	Raymond K. Kershaw	International Transmission Company
1/12/2003	Standards Development	Transactions are generally modeled as a group of generators in the sending control area to another group of generators in a second control area. This model has a generally acceptable level for many transactions but could be improved by going down to the individual generator, such as an IPP (if known). However, we still like the "control area" model if the "speed" of curtailing a transaction is important. *In an emergency, its better to move a group of generators as opposed to one generator. In an emergency, is better to ignore the "economics" of curtailment and perform the most expeditious operation* .	Raymond K. Kershaw	International Transmission Company

Date	Rec Type	Recommendations/ Comments	Name	Organization
1/12/2003	Standards Development	The IDC uses whatever generator model that is in the Eastern Interconnection (EI) base case. It is supposed to mimic actual dispatch. Why "mimic" the dispatch? *We recommend that actual generator dispatch be inputted and updated every five minutes.* Because this has commercial implications, the IDC needs to have enhanced cyber security. We think it already has this security level but its worth a second opinion. Native and network load (NNL) calculations would benefit from this enhanced granularity.	Raymond K. Kershaw	International Transmission Company
1/12/2003	System Operations	We recommend that graphical displays, similar to Figure 6 of the IDC report, be available to all Reliability Coordinators prior to implementing a TLR. These displays will show the RC the total relief available through transaction curtailment or internal network redispatch. It shows the TLR level necessary to achieve the relief required on a flowgate. Had this been available on Aug 14, a TLR level 5B might have been chosen over the level 3B that was asked for.	Raymond K. Kershaw	International Transmission Company
1/12/2003	Training	All Reliability Coordinators should have and use a contingency analysis tool capable of evaluating existing system conditions or projected conditions following the next credible contingency.	Raymond K. Kershaw	International Transmission Company
1/12/2003	Investment	The primary motivation behind making this suggestion is that entities that were depending on EMS state estimators to provide them system monitoring seemed unable to cope with loss of this process. Because tools and processes are available to provide a rudimentary form of monitoring, they should be taken advantage of as backup to their main EMS systems.	Raymond K. Kershaw	International Transmission Company
12/10/2003	Vegetation management	The U. S. -Canada Power System Outage Task Force should research, evaluate, and consider mandating tree and brush to wire clearances for distribution and transmission lines similar to those in effect in California. Any regulations or standards promulgated should have significant economic penalties to ensure utility compliance.	Richard E. Abbott	Personal comment
12/10/2003	Vegetation management	A minimum of two years should be the timeframe for the utility to achieve compliance with the regulations or standards with an increasing percentage completion at each six-month interval. The Task Force should establish a plan for implementation and staff so they can inspect tree, brush, and tree-to-wire clearances for compliance with regulations.	Richard E. Abbott	Personal comment
12/10/2003	Vegetation management	The modern jet-powered helicopters are too fast for an accurate detailed review of tree and brush conditions	Richard E. Abbott	Personal comment
12/10/2003	Vegetation management	The utilities should immediately conduct a foot patrol, vegetation management brush control, and danger, dead, or dying tree survey of all transmission lines and provide a schedule to eliminate vegetation management problems noted. The utilities should conduct a tree and brush control survey of their system to determine accurately numbers of trees burning in wires, number of danger trees, acres of brush, tree and brush control workload, etc.	Richard E. Abbott	Personal comment
11/25/2003	Unclear	Page 107 under "Findings to Date" may require further clarification. "The existence of both internal and external links from SCADA systems to other systems introduced vulnerabilities."Are these links unidirectional or bidirectional? If these links are unidirectional then which way "to SCADA" or "from SCADA"? Was data passed from SCADA to other systems, data is taken from other systems to SCADA or both?	Rick Fernandez	none given

Date	Rec Type	Recommendations/ Comments	Name	Organization
11/25/2003	Unclear	Page 107 under "Findings to Date" may require further clarification. "Although there were a number of worms and viruses impacting the Internet and Internetconnected systems and networks in North America before and during the outage" Does this mean that there were "worms and viruses" impacting the whole Internet (corporations not involved in the outage) or does it mean those "worms and viruses"? Were impacting the networks of the corporations directly involve in the outage? If this "worms and viruses" were impacting the networks of the corporations involved in the outage then further investigation is going to be required.	Rick Fernandez	none given
11/20/2003	Editorial Comment	In the text box in Page 19, the statement that "the bulk power system has no memory" may not be appropriate when thermal limits are discussed. We all know that the historical loading of a circuit would affect the thermal limits of it. That is why we have the Maximum Continuous Rating, Cyclic Rating and Emergency Ratings.	Shihe Chen	Power Systems Business Group, CLP Power Hong Kong Ltd.
1/11/2004	Safety Net	I made a presentation about voltage & reactive power issue in breakout session 3 at the Toronto conference. Future blackouts may be reduced, if the reactive reserves in EHV network will be kept with a balance between generators and sub-stations by applying our recommending practices. What is the preferred end state: a) Follow NERC Planning Standards; b) Voltage profile should be kept in sending end with generators and in receiving end with shunt capacitor/reactor banks; c) Apply high side voltage controller (PSVR) to generators connected to EHV networks in order to keep reactive power reserves at EHV networks during multiple contingencies (Category A, B and C) following the NERC planning standards; d) Install shunt capacitor/reactor banks switched by microprocessor-based controllers (VQC) to regulate high-side voltage at EHV substations, in order to keep reactive power reserves at EHV networks during multiple contingencies (Category A, B and C) following the NERC planning standards.	Shinichi Imai	Tokyo Electric Power Company
1/11/2004	EDIT	Clarify the application criteria for Under Voltage Load Shedding as SPS. TEPCO criteria are described as follows: The load shedding shall be prevented by keeping reactive power reserves against credible multiple contingencies like loss of a double circuit line; and SPS for automatic under voltage load shedding was installed to prevent cascading against more severe contingencies like multiple outages during extreme weather and heavy load.	Shinichi Imai	Tokyo Electric Power Company
11/22/2003	VAR	A search of the Interim Report for the word "reactive" shows that it is used many times, but the physical nature of reactive power as VI sin(phase angle) is not mentioned once. The way the term is used is confusing, at best. In summary, the wording in the Interim Report of "reactive power" appears to me to be misleading, as representing it as something deliberately produced and shipped, rather than an effect produced by inductive motor loads which can be corrected by shunt capacitors. I would appreciate it if you could let me know if power factor cannot be corrected near the motor loads, and so not be a burden on generators in generating plants.	Sidney A. Johnston	Personal comment
12/2/2003	Safety Net	Questions I would like answered are: What caused the Eastlake #5 unit to trip which probably started the process? Why didn't low frequency relays automatically separate First Energy's interconnections and prevent the cascading outage?	Sidney Spencer	Personal comment

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/24/2003	Investment	Although the lack of investment is the underlying problem, experts say there must have also been some technical fault which failed to stop the domino effect. But the problem area should have been isolated rather than allowing the lights to go out in each region in turn. Some experts blame this on a computer failure, while others say people at control centres should have been able to trip the necessary switches to stop the problem escalating. [switches = SCADA/EMS]	spider	Personal comment
12/24/2003	Prevention	I'd like to add that the SCADA system was supposed to island the problem areas. The power system was supposed to operate normally when any system went down. This process did not happen. Thus the SCADA controls did not break each system into an island as designed. No doubt that fingers will point to every direction to obfuscate this fact.	spider	Personal comment
12/24/2003	Comment	GAO report April 1999 NERC has identified a large number of Year 2000-related risk factors that may impact the operation of electric power systems. The internal risk factors include generator outages, constrained operation of nuclear power plants, partial loss of EMS/SCADA systems, loss of portions of company-owned data and voice communications, and a failure of environmental control systems. According to the assumptions suggested by NERC for contingency planning purposes	spider	Personal comment
12/24/2003	Investment	"What's not been invested in during the last 40 years is the infrastructure for transmission and distribution, including the hardware and software that power SCADA systems," he said, referring to Supervisory Control and Data Acquisition Systems, which are real-time computers used to manage grid capacity.	spider	Personal comment
12/3/2003	Communication	Appropriate regulatory action is needed to ensure that communications facilities remain operational in the event power is lost on such a wide ranging basis again it is RECOMMENDED that the Task Force earnestly inquire with the Federal Communications Commission and Industry Canada as to the necessity of requiring broadcast outlets to maintain emergency operating power capabilities to face situations such as widespread blackouts. The ability to disseminate information to cope with a loss of power is impaired if critical outlets for disseminating information are crippled by such a loss.	Stephen Kellat	Personal comment
12/11/2003	Edit	p. 45 -- Last paragraph includes sentence "After Star-South Canton locked out at 15:41 EDT... Star-South Canton was within its emergency rating." After lockout, this line presumably carried no flow. Was the intent to say that Sammis-Star was within its emergency rating?	Steve Leovy	Personal comment
12/11/2003	Edit	p. 51 -- word "manned" should be "manner" p. 55 -- reference to Figure 5.8 in column 2 should be to 5.9. p. 65 -- Figure 5.18 shows generating units that tripped during the disturbance. Edgewater unit 4, located in Sheboygan, WI, tripped as a consequence of the disturbance, but is not shown (see, e.g. http://www.atcllc.com/documents/2003%20Z4%20Meeting%20presentation%20final.pdf).The figure title refers to "Power Plants" but presumably you really mean to say 'generating units' here.	Steve Leovy	Personal comment

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/11/2003	Edit	p. 67 -- Figure 6.1 lacks a clear explanation. You could use bubbles representing individual events, but the reader may incorrectly that each bubble in the graph is uniquely located on the basis of the size and frequency of the associated individual disturbance. However, there is no well-defined frequency for any individual event, since each event is unique. It appears that the intent is to show an inverse cumulative frequency distribution, i.e. P(C>=Ci), vs. Ci, the number of customers affected. If a clear explanation were provided, plotting the data this way would probably be acceptable. Try expanding note to "The bubbles represent individual outages in North America between 1984 and 1997, plotted against the frequency of outages of equal or greater size over that period."	Steve Leovy	Personal comment
12/11/2003	Edit	The report refers to certain FE lines as tripping at power flows below their emergency ratings (p. 34). The report does not make clear whether this assertion takes voltage into account. That is, it is not clear whether this statement considers actual ampere flows relative to ampere ratings or whether it considers only actual MW flows (at one end of the line) relative to the nominal MW rating. This should be clarified.	Steve Leovy	Personal comment
12/11/2003	Editorial Comment	The Report says (p. 28) that, with Eastlake 5 in service, no overloads above emergency ratings would have occurred. It goes on to imply that this means that the Eastlake 5 outage was a critical step. This is logically not necessarily correct given that the report found that key lines in the chain of tripping tripped at below their emergency ratings. For these lines, loading relative to emergency ratings may be the relevant measure for NERC Standard compliance, but it is not the correct standard for determining the thresholds associated with the actual disturbance. The key test necessary to support the assertion in the report is whether, with Eastlake 5 in service, the lines whose outages played a role in the initial cascading failure would have had loadings reduced below the level at which they actually tripped (with voltage and reactive flows taken into account).	Steve Leovy	Personal comment
12/11/2003	Editorial Comment	The report leaves some key questions unaddressed: Would disturbance have been avoidable if FE and MISO had been better aware of outage situation? Transcripts of August 14 detailing the cumbersome process for developing TLR for new flowgates, and the unwillingness to curtail load declared by FirstEnergy after the blackout, raise questions. If these factors would have made the disturbance difficult to avoid even if better situational awareness had been available, as seems possible, then the report should discuss this.	Steve Leovy	Personal comment
12/11/2003	Editorial Comment	Could MISO have prevented this effectively within MISO, or would effective action have required close coordination with PJM? Did separation of the region between RTOs, and AEP's non-participation in an RTO, impair response to emergency conditions? If the ugly PJM-MISO seam detracts from reliability, as seems likely, the report should discuss this.	Steve Leovy	Personal comment

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/11/2003	Comment	I am in a position to state that the time sequence of failures seems superficially consistent with a Blaster instance scanning through a Class B network, if the affected control systems had IP addresses scattered through that address segment. It is likely that, if I had access to at least the last two octets of the IP addresses of the various systems which failed and the exact failure times, I could fairly conclusively confirm or deny computer expert Bruce Schneier's (http://rss.com.com/2010-7343-5117862.html?tag=nefd_gutspro)speculation that Blaster was in fact involved (the IP addresses and failure times alone would probably suffice, without any firewall or IDS logs - however, the latter would certainly be of great value also).I would like to offer my assistance to that end. I am happy to sign an NDA if necessary to get access to the relevant data, and would be happy to co-ordinate eventual publication of any such analysis with the Task Force.	Stuart Staniford	Personal comment
12/11/2003	Editorial Comment	The conclusion of the report that there is no evidence for a role for cyber-attacks in the events seems premature (particularly given Al Qaeda's claim of responsibility and previous news coverage that they had been studying SCADA systems with a view to conducting cyber-attacks on them).Your interim report has a timeline showing that multiple computers and software systems, which sound like they should have been independent, failed over the course of an hour, and that this occurred during the main spread period of the Blaster worm. While the interim report repeatedly states that there is no evidence of involvement of cyber-attacks, no substantiating detail is given to support this conclusion.	Stuart Staniford	Personal comment
11/28/2003	Standards Development	The US.-Canada Power System Outage Task Force's very comprehensive Interim Report: Causes of the August 14th Blackout in the United States and Canada appears to miss the most significant underlying cause of the event: The weather conditions in Ohio of August 14, 2003 were very atypical for the season. Particularly, low wind speeds caused overhead lines to operate at much higher temperatures than assumed for utility ratings. Over the past three decades, many utilities in the Midwest have gradually increased their transmission line ratings, either by assuming more benign thermal rating conditions, by relaxing their line clearance buffers, or by a combination of both techniques. Over the same period, line loadings have increased significantly. As a result, transmission lines are now operated at substantially higher temperatures. The consequences of unfavorable weather conditions (such as calm – zero wind speed) have become much more dangerous than before.	Tapani O. Seppa	The Valley Group, Inc.,
11/28/2003	Editorial Comment	Page 37: This single sentence contains both errors & statements subject to misinterpretation,"On August 14 wind speeds at the Ohio Akron-Fulton airport averaged 5 knots around 1430 EDT, but by 15:00EDT winds speeds had fallen to 2 knots (the wind speed commonly assumed in conductor design) or lower." Explanations: a)Airport wind speed measurements are single hourly observations, not averages. Especially for low wind speeds, an observation 5 min earlier or later could have a completely different value.The only way to use airport wind speed observations for a study of this event is by a method such as used in [I], i.e. statistical treatment of weather data from multiple sites...	Tapani O. Seppa	The Valley Group, Inc.,

Date	Rec Type	Recommendations/ Comments	Name	Organization
11/28/2003	Wind Speeds	b)The observation at 1500 EDT was zero knots. Anemometer stall speeds are about 2-2.5 knots, the effective wind speed could have been zero c)Airports are in open spaces, while transmission lines are partially sheltered, wind speeds in transmission line corridors are generally only about one half of those measured at airports d)The most common wind speed used in rating assumptions in the U.S. is 2 ft/sec, not 2 knots(3.4 ftlsec) e)Even if the wind speed measured at the airport were 2 knots, the cooling effect of the wind depends on the angle between wind & the conductor. If the wind was parallel to the line, its cooling effect was less than one half of a perpendicular wind. Thus an observation of a 2 knot wind velocity would not mean that a rating based on a 2 knot perpendicular wind is safe.	Tapani O. Seppa	The Valley Group, Inc.,
11/28/2003	Editorial Comment	The Valley Group, Inc. has collected large amounts of data on real time transmission line rating conditions in many areas of the U.S., as have other researchers. We have found that in most of the U.S., the assumption of 2 Wsec perpendicular wind is only marginally safe. A more safe assumption would be a 2 ftkec wind at an angle of 45 degrees, coincident with an assumption of a high daytime temperature and full solar radiation. This is roughly equivalent to a 1.5 Wsec perpendicular wind velocity. Some countries specify by law the weather conditions which are to be used in transmission lines ratings. Such countries include Germany (0.6 mds) and Japan (0.5 mls).	Tapani O. Seppa	The Valley Group, Inc.,
11/28/2003	System Operations	NERC contingency definitions are partly responsible for the operator confusion. NERC definitions make no clear distinction between voltage and stability based contingencies on one hand and on thermal contingencies on the other hand. In the early stages, before 14:40 EDT, the evolving problem could have been contained with actions of relatively minor consequences, if the operators would have had information regarding the state of the endangered lines and sufficient training to react to the events. Once the voltage collapse began, NERC's 15 minute mandated reaction time was meaningless.	Tapani O. Seppa	The Valley Group, Inc.,
11/28/2003	Training	Operator transcripts bear evidence that most operators have only a vague understanding about the time limitations related to emergency conditions and the serious impact of preload conditions on conductor temperature and sags. If the preload of a transmission line is high, the operator has only a short time to react to a thermal emergency load.	Tapani O. Seppa	The Valley Group, Inc.,
11/28/2003	Training	There appears to be an overall lack of understanding about the primary reason for thermal limitations, that of public safety, and an overemphasis on the secondary reason, avoiding the damaging of equipment. For overhead lines, damage to conductors occurs only after extremely long and severe overheating. On the other hand, public safety is endangered every time lines sag below their minimum code-mandated clearances, even if for a short time. It appears that at least some of the transmission line owners are not aware that maintaining NESC minimum clearances is mandated also under contingency conditions.	Tapani O. Seppa	The Valley Group, Inc.,

Date	Rec Type	Recommendations/ Comments	Name	Organization
11/28/2003	Reliability Standards	FERC should establish a task force to define clear and consistent rules regarding the methods by which transmission owners determine the thermal limits of transmission lines. Such rules should include: a) methods by which relevant weather and conductor data is collected for and applied to line rating calculations) or alternatively, the use of line monitors for establishing the rating parameters; c)methods by which line sags are calculated and the related minimum safety clearance margins; d) and clear definitions for the use of normal and emergency ratings, and allowable time limitations.	Tapani O. Seppa	The Valley Group, Inc.,
11/28/2003	System Operations	Operation of transmission lines with loading in excess of the established thermal limits should be allowed only when lines are monitored by real time thermal monitoring equipment, ensuring deterministic safety while allowing higher ratings under favorable weather conditions.	Tapani O. Seppa	The Valley Group, Inc.,
11/28/2003	Training	NERC should establish a training guide for all system operators regarding the reasons for and application of thermal ratings.	Tapani O. Seppa	The Valley Group, Inc.,
11/28/2003	Comment	It is suggested that FERC and NERC ask for technical assistance in these tasks from the relevant committees of CIGRE (Study Committee B2) and IEEE (Transmission Line Conductors and Accessories Working Group of the Towers, Poles and Conductors Subcommittee).	Tapani O. Seppa	The Valley Group, Inc.,
1/15/2004	Standards development	Our company, Orion Associates International, Inc., has been performing physical audits of power plants and transmission facilities for ISO's since 2001. We have done 17 power plant and 7 transmission audits to date. We have the resources & experience to begin such a program for FERC or NERC without delay. The question of sanctions always comes up when audits are discussed. An audit program which lacks effective sanctions will not be taken seriously by the bulk power industry. Financial sanctions are not necessarily effective, because facility owners will find a way to treat the penalties as operating costs. I would suggest instead that a reliability rating system be developed similar to what the A.M. Best company provides to the insurance and surety industry. Facility owners could be rated according to the nature and frequency of violations of reliability standards and outages within their service areas or caused by them in adjacent areas. If those ratings were made available to financial institutions investing in the electric power industry, reliability would suddenly become important to the	Thomas J. Burke, PE	Orion Associates International, Inc.
12/11/2003	Editorial Comment	Your "confidentiality" gag order imposed on investigation participants appears to be unjustified and unnecessary. As a result, your government-controlled report lacks the full credibility it could, and should have; and therefore risks becoming a disservice to the public.	Tom Besich	Electric power Engineer
12/5/2003	Training	I am troubled by the discrepancy between statements from FirstEnergy that their people were trained, and the Interim Report, which says they were not. If the training documented for FirstEnergy operators and supervisors is the same as that given to people in, for example, the PJM area, perhaps the training provided is adequate but the personnel selection is not. If adequate training was not provided, were those not adequately trained working under the direct supervision of a person trained (and qualified) for that work assignment?	Tom Gurdziel	Personal comment

Date	Rec Type	Recommendations/ Comments	Name	Organization
11/23/2003	Communication	Were there too many FirstEnergy operators on duty to communicate between themselves efficiently? And, too many supervisors with overlapping authority? 3. Were outgoing personal telephone calls a distraction? 4. Do FirstEnergy operators refer to strip chart recorders while on duty? Do they know how to put them on fast speed? How frequently, and for how long do they straight line? 5. Did the operating shifts change sometime in the afternoon of August 14th? Do the incoming operators get a turnover? Do they sign a sheet that says they checked or walked down any instrumentation, displays, or computer/compute programs? Did they?	Tom Gurdziel	Personal comment
12/2/2003	Edit	Page 46 "and two were really relay scheme mis-operations. They're category other." Does this mean circuit breaker coordination is faulty and not acknowledged?This is a particularly slick answer. You use the root cause tactic of grouping or categorizing things to, usually, allow you to attack the cause of a problem that has surfaced in a number of places. However, in this case you use categorizing to allow you to avoid even acknowledging a problem exists. (Apparently, the transmission line owner does not take responsibility for the relay logic, or "scheme.") The big question here is, how many other sections of their transmission lines don't have proper circuit breaker coordination.	Tom Gurdziel	Personal comment
12/2/2003	Edit	Page 46 "FE was conducting right-of-way vegetation maintenance on a 5-year cycle" Is this a claim, or did you see records that they had been trimming in this same place five years (or less) ago?	Tom Gurdziel	Personal comment
12/2/2003	Edit	Page 45 Is a summer emergency rating of 1310 MVA for Sammis-Star prudent? Is a summer normal rating of 1310 MVA prudent for this line?	Tom Gurdziel	Personal comment
12/2/2003	Edit	Page 35 Line Ratings For the three 345 kV lines that had the normal and emergency rating the same, was this because they lowered the emergency rating (to keep its internal temperature below 90 degrees C.) or raised the normal rating to 100 degrees C.?	Tom Gurdziel	Personal comment
12/2/2003	Edit	page 36 When the tree trimming crew observed the tree/line contact on the Hanna-Juniper line, was the contact on a section that the crew had just cleared?	Tom Gurdziel	Personal comment
12/2/2003	Edit	Page 42 "..voltages were below limits, and there were severe line overloads. But FE did not follow any of these procedures on August 14,.." The "because" part following these words seems, to me, to be exceedingly generous. Shouldn't these words alone be sufficient to require the operators to act regardless if they knew or did not know that the "system might need such treatment"? In fact, isn't that the purpose of having procedures?	Tom Gurdziel	Personal comment
12/2/2003	Edit	Page 43 "At that point in time, FE operators began to think that their system might be in jeopardy - but they did not act to restore any of the lost transmission lines, clearly alert their reliability coordinator or neighbors about their situation, or take other possible remedial measures (such as load-shedding) to stabilize their system." What is it they think they are getting paid to do? What did their supervisors and managers do?	Tom Gurdziel	Personal comment

Date	Rec Type	Recommendations/ Comments	Name	Organization
11/23/2004	Edit	Page 17, Table 3.1 I would prefer that you remove the words "NRC-ordered" from the Reason column for the Davis-Besse Nuclear Unit. Perhaps "NRC-negotiated" would be better. The actual fact is that the plant was obligated to shut down by 12-31-2001 but FirstEnergy, claiming the plant was in good repair, negotiated a later shutdown.	Tom Gurdziel	Personal comment
11/23/2004	Edit	Page 20, Figure 3.5 Am I reading this correctly? It looks like the Eastlake Unit 5 was lost due to operator error in adjusting the Exciter to about 400 MVAr (where the rated limit was about 360 MVAr AND apparently changing voltage control from manual to automatic. Was the plant, a FirstEnergy plant I believe, also operated by FirstEnergy? In any event, was the person making these changes adequately trained and supervised?	Tom Gurdziel	Personal comment
12/3/2003	Edit	I enjoyed reading this report and found it to be a great deal more comprehensive than I had expected. I thought the writing was especially well done and think I (generally) understood everything except the Canadian reactors, on which I have no experience.	Tom Gurdziel	Personal comment
12/4/2003	System Operations	Is it considered good practice to do so called "Fitness for Duty"(drug/alcohol) testing after such an incident? In the MISO-website-available communication channel transcripts, (I read the first 3 or 4 of, I believe 7), MISO people did not reduce generation when this would have been helpful. (Wheatland) How can they be called operators when about all they do is observe?	Tom Gurdziel	Personal comment
12/4/2003	Safety Net	How can any generator, (utility or independent), be allowed to supply electric power over transmission lines without also being required to provide, (by themselves or by purchase from others), sufficient reactive power to keep the grid safe/secure? (I don't know the proper word.)	Tom Gurdziel	Personal comment
12/4/2003	Comment	Who is responsible for regulating transmission line companies in Ohio, perhaps even with authority to set rates for them? Do you think each one of these agencies has done the job entrusted to them?	Tom Gurdziel	Personal comment
12/4/2003	Vegetation management	Does "tree trimming" as practiced by FirstEnergy consist of cutting trees and shrubs to a height that will probably mean, in 5 years, the vegetation would still be clear of the power lines? (Or do they just cut off a couple of feet?)	Tom Gurdziel	Personal comment
11/24/2003	Vegetation management	The last time they (Niagara Mohawk Power Company, now owned by National Grid), trimmed the trees, they cut down all the trees near enough to fall on the lines and pushed them to the side. Actually, we found we could no longer take our usual path because there were so many trees pushed to the side that they formed a hard to climb fence there (well, with an old dog anyway). Under the lines, growth is trimmed with massive rubber tired machines that serve as commercial sized lawn cutters. So, I would say, before I would believe this "cut and stack" story, I would look to see all the other trees cut and stacked. If I couldn't see any, I would conclude that evidence was removed.	Tom Gurdziel	Personal comment
12/3/2003	Comment	In the voice transcripts made available by (I believe) MISO, I think there is a need to standardize the identification of pieces of transmission lines. Most people described the lines by geographic description but one company described them by voltage and sequence number. I thought this was unnecessarily confusing.	Tom Gurdziel	Personal comment

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/3/2003	Training	Does FirstEnergy have procedures and training materials? page 103 "(in relation to reactive capability or voltage levels), and system impacts associated with unavailability of the Davis-Besse plant." If the Davis-Besse generator had been disconnected from the turbine and used as a synchronous condenser, (a rotating machine acting as a capacitor, I believe), would this have helped the situation? I believe, at this time, this plant had been down for about 18 months, so plenty of time had been available to do this.	Tom Gurdziel	Personal comment
12/3/2003	Training	page 74 "Written procedures and training materials should include criteria that system operators can use to recognize signs of system stress and mitigating measures to be taken before conditions degrade into emergencies."	Tom Gurdziel	Personal comment
12/5/2003	Safety Net	As a remedial action scheme, trips by the Over Loading Relay (OLR) may cause the other equipment to be overloaded, resulting in a cascading failure. To prevent this kind of cascading trips, an automatic load-shedding scheme to the overload will be the most effective measure to take.	Toshihiko Furuya	Director and General Manager
12/5/2003	System Operations	In the case that the power system operation depends on Real Time Contingency Analysis (RTCA), it is expected that RTCA may not be functioning due to EMS failure and it may also be difficult for RTCA to cover a huge number of N-2 contingency analyses. Therefore, we recommend that system operators conduct frequent off-line simulation analyses by the detailed simulation models of various power systems.	Toshihiko Furuya	Tokyo Electric Power Co., Inc.
12/5/2003	Market and Deregulation	Operating conditions of power systems have drastically changed due to the deregulation. For example, system operators increasingly trade electricity across a wide area, but have they strengthened their power systems to facilitate such trade in an effort to prevent a cascading power failure? We also believe that the equipment should be strengthened appropriately, with consideration given to preventing cascading power failure.	Toshihiko Furuya	Tokyo Electric Power Co., Inc.
12/5/2003	VAR	We suppose that the supplied amount of reactive power and the voltage control management were not adequate. In this regard, we would like to recommend that the management of both active and reactive power flows should be unified over the network, at the same time, each control area should take the necessary measures to supply reactive resources required within its boundaries. We recommend installing larger numbers of shunt capacitors in the areas where the voltage fell, and allocating the amount of reactive power by generators at a lower rate capacity than used under normal conditions. This would prepare you for any possible accidents.	Toshihiko Furuya	Director and General Manager Tokyo Electric Power Co., Inc.
12/5/2003	Grid Integration	The Interim Report does not contain sufficient detail to answer some important questions with regard to New York's being separated from the Eastern Interconnection and additional outside load being isolated onto the New York system.	William J. Museler	New York Independent System Operator (NYISO)
12/5/1930	Legislation	Interestingly, the Interim Report seems to support the recommendations we made in testimony before Congress and before the New York State Legislature.	William J. Museler	New York Independent System Operator (NYISO)

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/5/2003	Reliability Standards	Mandatory operating standards are a necessity. While NYISO has been obligated by contract to adhere to the NERC standards, but the August 14th, events showed that New York can be profoundly affected by other areas violating those who violate that standard.	William J. Museler	NYISO
12/5/2003	Investment	The Interim Report concluded that MISO and neighboring control areas, as a result of equipment and operational failures in Ohio, never received vital information that might have mitigated the impact of the initiating problems. If MISO had such information, according to the Interim Report, the MISO operators would have become aware of these line outages earlier. This finding buttresses another one of our earlier recommendations, which was that communications among the ISOs, RTOs and control areas need to be significantly improved. In this regard, some of the joint government/CERTS projects such as the Eastern Interconnection Phasor and the Wide Area Performance projects should be supported, and if possible, accelerated.	William J. Museler	NYISO
12/5/2003	Communication	Better communication needs to be accompanied by prearranged and effective operator procedure. At the present time, there is no expectation that a non-adjacent system operator would communicate to other, non-contiguous control areas the existence of a condition or disturbance on its system or other systems that could jeopardize the neighboring regions. It is obvious that communications improved in this respect would make possible anticipatory actions that might prevent the spread of a problem.	William J. Museler	NYISO
12/5/2003	Reliability Standards	We believe that participation in an ISO, RTO or tight power pool for reliability purposes should be mandatory. In many parts of the Country, participation in ISOs or RTOs is controversial, but most of the controversy is related to deregulation and the establishment of markets. It ought to be possible to separate the market concerns from the reliability concerns, making mandatory participation more acceptable.	William J. Museler	NYISO
12/5/2003	TRAIN/ System Operations	Simply put, if the “rules” had been followed and the companies involved had enforced compliance with the rules, the blackouts would have either been avoided or made much less severe. The “fixes” for these reliability failures must concentrate primarily on these root causes; the rules, the training, and the obligation of the personnel and companies involved to follow those rules.	William J. Museler	NYISO
12/5/2003	Editorial Comment	I am concerned that a hearing was held in Cleveland this week with virtually no notice whatsoever to the general public. I have a great deal of experience with public hearings on utility matters, and it is obvious that the hearing this week was not properly noticed and insufficient time was provided in advance of the hearing to allow the public to be informed about it and to prepare to attend and to speak at it.	William M. Ondrey Gruber	Attorney

Date	Rec Type	Recommendations/ Comments	Name	Organization
12/5/2003	Market and Deregulation	The incomplete and haphazard restructuring of the retail electric utility industry in Ohio starting in 2000 and 2001 has created an atmosphere that has allowed FirstEnergy to neglect transmission and distribution facilities and to concentrate on business activities other than those related to the provision of basic retail electric service. The Public Utilities Commission of Ohio bears its share of responsibility for the restructuring disaster in the State. It allowed FirstEnergy, contrary to law, to begin its transition to an unregulated generation market without first creating or participating in an independent and competent transmission system operator. I hope that your investigation will not rely on Ohio's Public Utility Commission to look into the problems with FirstEnergy's operations and management and its oversight of the necessary actions that must be taken by FirstEnergy to fix its many problems and protect the reliability of electric service in Ohio and the region.	William M. Ondrey Gruber	Attorney
1/5/2003	Reliability Standards	We suggest that local, regional and national reliability standards recognize special local and regional conditions and having such rules mandatory over all entities that design and operate power systems as well as all market participants that use the transmission system.		New York State Reliability Council (NYSRC)