A Review of System Operations Leading up to the Blackout of August 14, 2003

North American Electric Reliability Council
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System Operations and Reliability Coordination

The investigation into the blackout of August 14, 2003, included a thorough review of the operating practices of the reliability coordinators and control areas of the electric systems that were directly involved in the blackout. This report focuses on problems that U.S.-Canada Power System Outage Task Force and North American Electric Reliability Council (NERC) investigators found with the actions system operators took or failed to take on August 14, and provides recommendations for preventing those problems from recurring. Much of the information contained in this report was derived from on-site interviews of the affected entities.

Background

The North American bulk electric system is one of the most complex machines ever built. The system spans thousands of miles and connects thousands of electric generators to millions of end users through millions of discrete control points. The system delivers an enormous amount of energy to customers on a daily basis. If the system is not operated within defined operating parameters, that energy can be unleashed and result in severe equipment damage and even widespread blackouts. Although the system has many automated control systems to balance load and generation at every instant and to protect public safety when equipment or facilities are operating outside of design parameters, the system requires humans to operate it in a safe and stable manner.

NERC reliability standards are designed to ensure that the electric system is operated so that it can withstand any single disturbance — and sometimes multiple disturbances — without resulting in the cascading failure of the system. The Preamble to the NERC Operating Policies states:

> *All control areas shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. Multiple outages of a credible nature shall also be examined and, when practical, the control areas shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from these multiple outages.*

There is no way to prevent disturbances — credible or otherwise — from occurring. However, a successful reliability process will ensure that the transmission system will be operated in a reliable manner so that even multiple events will be unlikely to cause a cascading outage.

System operators have been at the center of every blackout investigation since the 1965 Northeast blackout, which was the catalyst for the formation of NERC (see Table 1). In almost every instance, had system operators taken appropriate actions, these blackouts would not have occurred. The August 14 blackout was no exception. The interim report of the U.S.-Canada Power System Outage Task Force found that the causes of the blackout were:

- Inadequate situational awareness by FirstEnergy (FE) system operators, and by Midwest Independent Transmission System Operator, Inc. (MISO) and PJM Interconnection (PJM) reliability coordinators.
- Inadequate tree-trimming by FE.
- Inadequate diagnostic support by the MISO and PJM reliability coordinators.
- Communication failures between system operators.
- Failure to recognize the developing emergency.
- Other root causes, contributing factors, and confirmed deficiencies.

NERC's investigation into the blackout confirmed these findings. This report provides recommendations to address the deficiencies in system operating practices identified during the blackout investigation so that these problems do not occur again.

Table 1 — System Operations Have Been at the Center of Every Major System Disturbance

November 9, 1965 — Northeast United States/Canada Blackout

- Systems control centers should be equipped with display and recording equipment which provide the operator at all times with as clear a picture of system conditions as possible.
- Coordinated programs of automatic load shedding should be established and maintained.
- Thorough programs and schedules for operator training and retraining should be rigorously administered.

July 13, 1977 — New York City

- The single most important cause of the July 13, 1977, power failure was the failure of the system operator to take necessary action.
- Make a thorough reevaluation of the selection and training of system operators.
- A full-scale simulator should be made available to provide operating personnel with hands-on experience in dealing with possible emergency or other system conditions.

July 2, 1996 — Western United States

- Review the need for a security monitor function to monitor operating conditions on a regional scale and promote interconnected system reliability.
- Review the need for tools such as on-line power flow and stability programs and real-time data monitors.
- Review the current processes for assessing the potential for voltage instability and the need to enhance the existing operator training programs, operational tools, and annual technical assessments.

August 10, 1996 — Western United States

- Coordination among regional members and with neighboring systems should be increased regarding maintenance schedules, underfrequency and undervoltage load-shedding plans, transfer levels, and system protection.
- Develop communications systems and displays that give operators immediate information on changes in the status of major components in neighboring systems.
- Strongly encourage operators to exercise their authority to take immediate action if they sense the system is starting to degrade.
- Train operators to make them aware of system conditions and changes.

Control Areas and Reliability Coordinators

Control Areas

In an electric interconnection, all electrical equipment is operated synchronously; the equipment within the interconnection essentially operates as a single machine. An interconnection must be continuously monitored and controlled to operate safely and reliably while providing dependable electric service to its customers. This monitoring and control function is distributed among the control areas that comprise the interconnection.

A control area is an electrical system bounded by tie-line metering and telemetry. Historically, the control area has been the entity with primary responsibility for maintaining reliability within its electronic footprint. Control area balances its generation to maintain its interchange schedule with neighboring control areas and contributes to the regulation of frequency within an interconnection. There are nearly 150 control areas in North America.

NERC reliability standards require that all electric demand and supply in North America be within the metered boundaries of a control area. The control area must control all of its supply resources (owned generation and scheduled interchange) so that the demand for electricity and resources to supply that demand are kept in balance at all times.

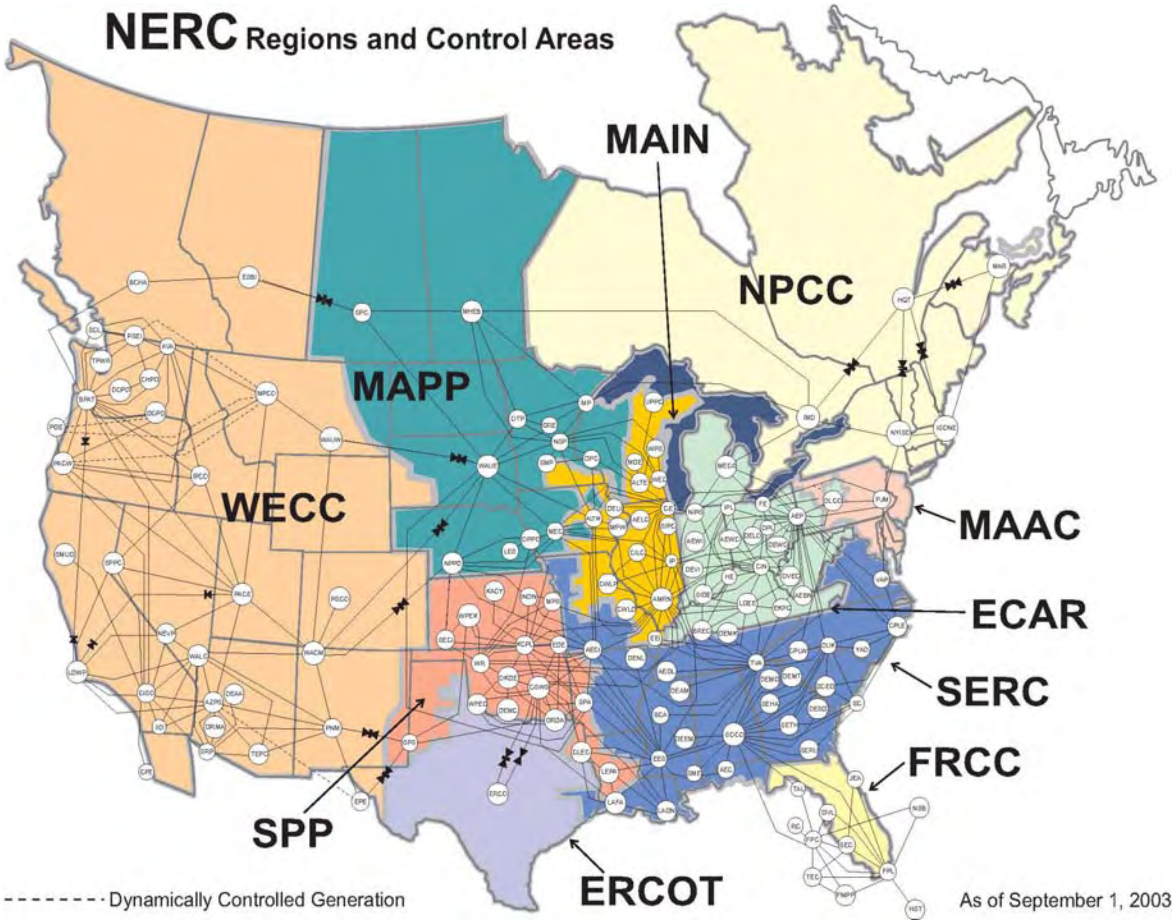
There are no guidelines for the size or shape of control areas. The size varies and some are in one contiguous area while others are comprised of several distinct and separate areas. Some control areas have been consolidated through mergers and some new generation-only control areas have been formed. In some cases, the role of the traditional control area has been consolidated into the operation of regional transmission organizations (RTO).

In the late 1990s, the Federal Energy Regulatory Commission (FERC) implemented rules that required utilities to separate, or “unbundle,” their transmission and distribution from their marketing and generating functions. To meet this requirement, companies unbundled in differing ways. Some utilities fully separated their generation dispatch and energy scheduling from transmission operations. Others separated the marketing and pricing responsibilities for their generation but left the control of the generation and transmission operations in a single operations center. In other cases, companies divested their generation or transmission assets altogether.

These changes have increased the complexity of the system operator’s job. The operator must understand not only what aspects of company operations they are responsible for, but also the responsibilities of multiple operators in neighboring systems.

Transmission system operators must evaluate both real-time and projected uses of the transmission system. They perform studies for real-time, next-day, next-week, next-month operations and even for operations many years into the future. Contingency analysis programs are important to transmission control areas in assessing the reliability of the interconnected EHV network. Contingency analysis studies evaluate the impact of taking various pieces of equipment out of service. The accuracy of the results of contingency analysis studies depends on the quality of the data submitted and the size of the area being studied. Generally speaking, the broader the area being studied and the higher the quality of the data, the better the result.

Figure 1 — North American Control Areas



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

FRCC
Florida Reliability Coordinating Council

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network, Inc.

MRO (MAPP)
Midwest Reliability Organization

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WECC
Western Electricity Coordinating Council

Reliability Coordinators

NERC established the Security (Reliability) Process Task Force in 1995 to identify what changes were needed to ensure reliable bulk electric operations in the face of significant changes taking place in the electric industry. The task force cautioned that reliability would be difficult to sustain given the level of information sharing between system operators and the varying degrees of control area-to-control area coordination of emergency procedures at the time. That task force concluded that better information sharing or better operational coordination, or both, was needed.

The task force also pointed out that recent regulatory and functional changes in the electric utility industry were increasing transactions across the system, including increasing emergency interchange during periods of high demand and the creation of complex interchange schedules from multiple sources. They noted that FERC's open access transmission tariff underscored the need for the industry to take certain actions to maintain system reliability and security while allowing evolving competitive wholesale markets to function effectively.

The task force recommendations resulted in the establishment of the current NERC reliability coordinators (see Figure 2) and the creation of networks to share operational data among control areas and reliability coordinators. In establishing the reliability coordinators and data-sharing networks, the task force noted that "*[s]ystem operators must be aware of all factors — internal and external — that affect the operation of their respective control areas, including the status of internal generation, load, and transmission conditions, and the type and amount of interchange with other control areas.*"

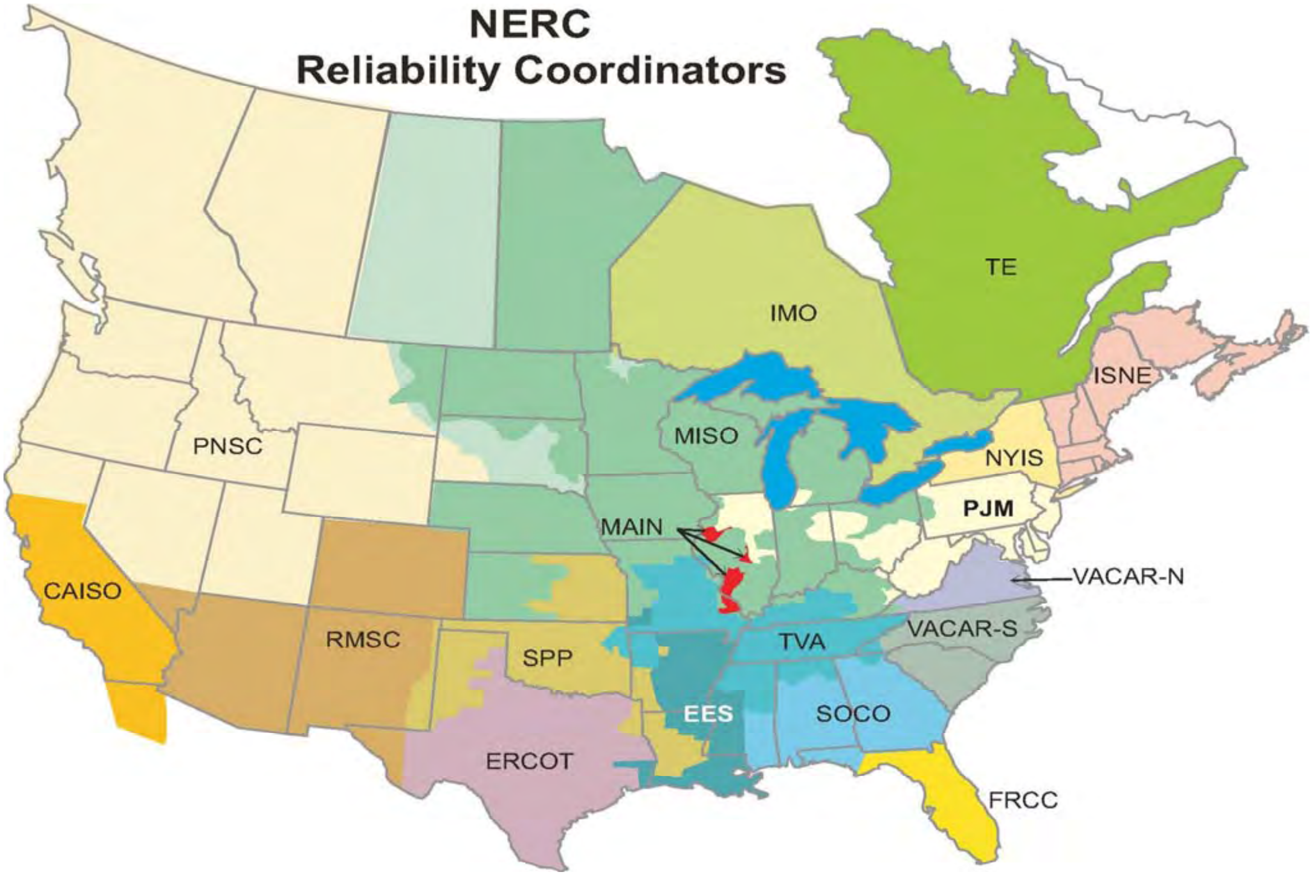
This same information is also needed from all other control areas whose operation might affect the performance of a control area. Because of the parallel flow effects of most scheduled interchange, interchange and other relevant information must be instantly available to all control areas within an interconnection in real time for security analysis. Other information that might affect operating decisions must also be shared.

The task force identified three key factors in the establishment of the reliability coordinators and improved information exchange to ensure operational security:

1. The need to have the "big picture," i.e., operational information about the other control areas in the interconnection.
2. The need to have accountability and authority to implement emergency operations, including line load relief procedures and activation of shared operating reserves.
3. The need to establish common terminology, criteria, and standards.

All three of these factors were implicated in the August 14 blackout investigation and are reflected in the recommendations contained in this report.

Figure 2 — Current North American Reliability Coordinators



Role of System Operators

Control area operators are akin to airline pilots for their portion of the bulk electric system. Their role is to monitor the portion of the system under their control and direct actions to ensure overall system reliability and safety. Much like an aircraft, there are a myriad of systems and controls that monitor and automatically take action to protect the system when disturbances occur. System operators are responsible for taking actions to keep their systems within defined operating limits and preserve the reliability of the grid while providing information to and following the direction of their reliability coordinator.

The reliability coordinator is more like an air traffic controller. Its role is to view the system from a much larger perspective to ensure that actions taken by the individual control area operators are appropriate and sufficient to preserve grid reliability, and to direct the actions of control area operators when necessary to preserve reliability. The complexities of performing these tasks have increased in recent years due to both the functional unbundling of the traditional utilities and the considerable growth of bulk power transactions on the system.

Historically, a single control center was responsible for estimating the electric demand within the control area for the day, dispatching generation to meet that demand, scheduling energy transactions with neighboring systems, and monitoring the health of the surrounding transmission system. With the implementation of functional unbundling, some of these functions were removed from traditional control centers making operation of the electric system in a reliable manner more complex. In some cases, a generation dispatch function was separated from the transmission operations function to ensure that the local transmission operator did not create a market advantage for the local generation resources. These changes, while beneficial to developing competitive markets, have increased the complexity of operating the system reliably.

Training

System operators and reliability coordinators must continually evaluate the health of the system and determine what actions must be taken to ensure reliable operations. The role of the system operator can be fairly mundane when the system is under little or no stress, but can be hectic and stressful when the system is experiencing outages, high loading levels, or unusual operating patterns. One of the premises of good utility operation is that the system operator must not only understand the current operating state of the system, but also must understand what the state of the system would be given an unexpected outage of the next most critical component or components.

To achieve this understanding, operators must continuously be provided with training. This training is necessary to ensure that the operators are fully prepared to take all actions necessary to preserve the reliability of the electric system, up to and including shedding firm load.

Control Centers

Control centers are the nerve center for system operation; all system data must be communicated to the center for processing and evaluation. Control centers are generally secure facilities designed to withstand natural disasters. NERC requires control areas to have a plan for continuing control center operations in case the primary control center cannot function.

NERC prescribes more specific requirements for reliability coordinators. Reliability coordinators are required to have a backup control facility in addition to a plan for transfer of their functions to a backup center. While NERC does not require a backup control center for control areas, most utilities of significant size maintain a backup control center both to maintain reliability and to ensure business continuity.

System Operator and Reliability Coordinator Tools

System operators and reliability coordinators must have access to the necessary monitoring tools, data, information, communication systems, and facilities to perform their tasks. System operators and reliability coordinators must also be able to communicate with each other regarding system conditions, scheduled equipment outages, and maintenance schedules.

System operators and reliability coordinators typically use off-line (non-real-time) studies to help them determine the safe loading limits of their transmission systems. These studies serve as base cases for long-term, steady-state normal operations. These types of analyses are performed both by operations support engineers using classical load flow study computer models, typically for the long term, and by system operators using dispatcher power flow tools for the near term. The load flow computer models are based on projections of system conditions and can be adjusted for current loads and generation patterns. The dispatcher power flow tools are generally located with the system operators. Because the dispatcher power flow tools capture actual system data, they can be used to evaluate possible system conditions. The dispatcher power flow is typically used to assess the impact of maintenance outages or other conditions the system operator wants to evaluate.

System operators and reliability coordinators typically use a security analysis program, or state estimator, to assess the health of the transmission system as close to real time as possible. The state estimator uses data gathered from the system and from its neighboring systems with near real-time accuracy to produce a computer simulation of the system as it is at that moment, checking to see that all flows, voltages, etc., in the computer model are within a certain tolerance of the actual values. The state estimator will calculate a realistic value to be used in place of bad or missing data. Using a contingency analysis tool to automatically simulate a series of transmission line or generator outages, system operators and reliability coordinators can then determine the effect that any number of contingencies will have on the system.

Using the results of the security analysis and contingency analysis programs, system operators and reliability coordinators maintain transmission security by adjusting generation, interchange, and transmission as conditions change. In this way, the operators of the transmission network ensure that the system is capable of withstanding any credible event without causing cascading outages and without exceeding safe loading limits on other parts of the system.

System Operator and Reliability Coordinator Events and Actions on August 14, 2003

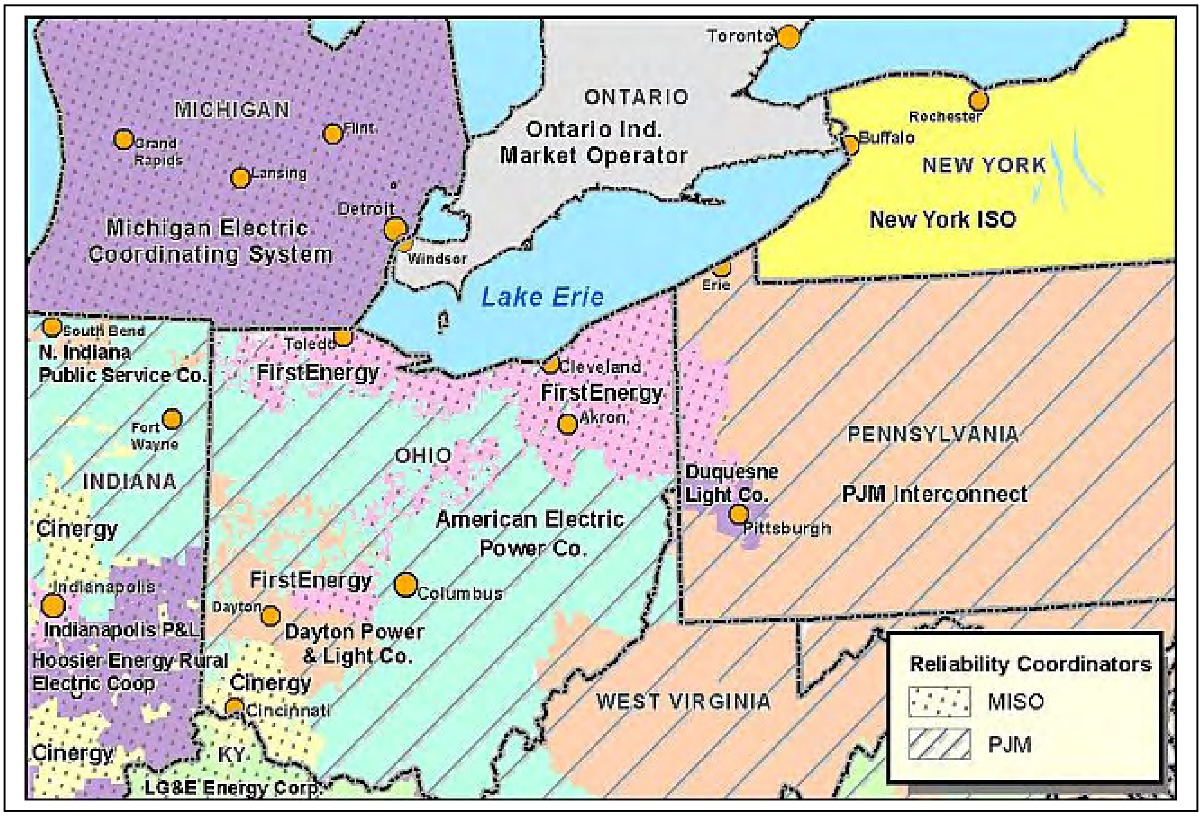
Numerous control areas and reliability coordinators were involved in the August 14 blackout. This report focuses on those entities in the immediate area where the blackout started and their reliability coordinators: FE, American Electric Power (AEP), PJM, and MISO. Other control centers that were affected by the blackout had only minutes to react to the cascading outage and NERC does not consider their actions to be of significance when discussing the events leading up to the blackout. Any actions the other control areas took in response to the blackout were not included in this investigation.

Investigators found that the sequence of events leading up to the cascading blackout presented a number of challenges to the various system operators and reliability coordinators. Most importantly, system operators did not have access to the information necessary to monitor and understand system conditions. Failures of necessary monitoring equipment meant that both the control areas and reliability coordinators did not understand what was happening on the system for an extended period of time. This was a contributing factor in the blackout. Investigators concluded that all of these events would have been manageable if the affected system operators and reliability coordinators had had the information and resources necessary to take appropriate action before the cascade began.

Midwest Independent Transmission System Operator

MISO is the reliability coordinator for 35 control areas, including FE. MISO is the reliability coordinator for a region of more than one million square miles, stretching from Manitoba, Canada, in the north to Kentucky in the south, from Montana in the west to western Pennsylvania in the east. MISO provides reliability coordination from two offices, one in Minnesota, and the other at the MISO headquarters in Indiana. MISO became the reliability coordinator for FE on February 1, 2003, when the East Central Area Reliability Coordination Agreement (ECAR) MET reliability coordinator became part of PJM. FE became a full member of MISO on October 1, 2003.

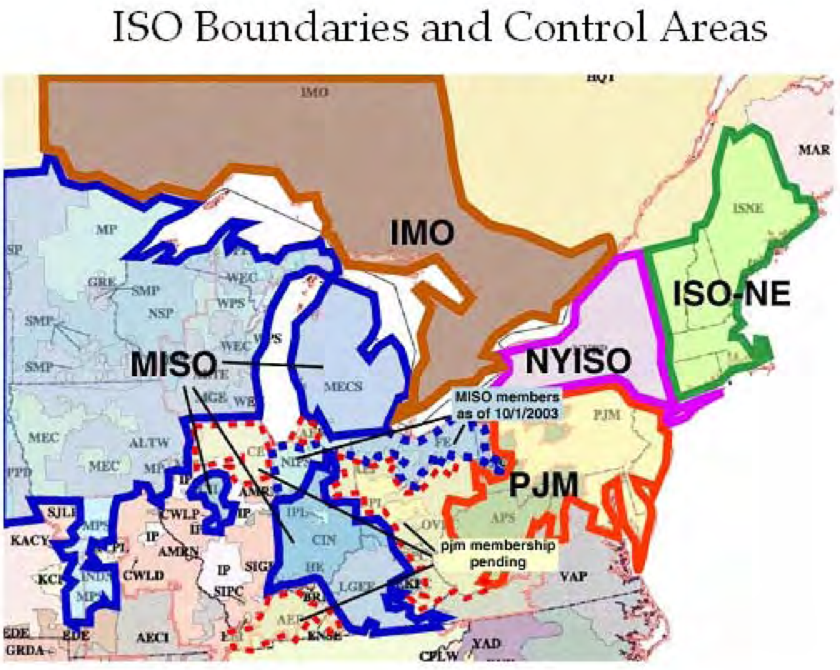
Figure 3 — Reliability Coordinators and Control Area Relationship in the Upper Midwest



PJM Interconnection

PJM is an RTO. PJM recently expanded its footprint to include control areas and transmission operators within the Mid-America Interconnected Network (MAIN) and ECAR (PJM-West). PJM became AEP's reliability coordinator on February 1, 2003. PJM performs its duties as a reliability coordinator in different ways, depending on the control areas involved. For MAAC (PJM-East), PJM is both the control area and reliability coordinator for ten utilities whose transmission systems span the Mid-Atlantic region of New Jersey, most of Pennsylvania, Delaware, Maryland, West Virginia, Ohio, Virginia, and the District of Columbia. The PJM-West facility has the reliability coordinator desk for five control areas (AEP, Duquesne Light, The Dayton Power & Light Co. (DPL), and Ohio Valley Electric Cooperative (OVEC)) and three generation-only control areas (Duke Energy's Washington County (Ohio) facility, Duke's Lawrence County/Hanging Rock (Ohio) facility, and Allegheny Energy Inc.'s Buchanan (West Virginia) facility).

Figure 4 — ISO Boundaries and Control Areas



source: Bechtel Nevada / NERC

American Electric Power

AEP is one of the largest electric utilities in the United States, with more than five million customers linked to the company's 11-state electricity transmission and distribution grid. AEP's 197,500 square mile service territory includes portions of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. AEP operates approximately 39,000 miles of electric transmission lines and more than 80 generating stations in the United States with a capacity of more than 38,000 MW. Prior to joining PJM, AEP was the reliability coordinator for a major portion of ECAR.

FirstEnergy

FE is the fifth largest electric utility in the United States with 4.4 million electric customers in a 36,100 square mile service territory covering parts of Ohio, Pennsylvania, and New Jersey. FE operates a control area that spans 11,502 miles of transmission lines, and 84 interconnections with 13 electric systems.

Overview of FirstEnergy Operations

FE operates several control centers within its Ohio territories. Each of these control centers performs different functions. The unregulated Conversion Economics group uses the generation management system (GMS) and is located in a separate building from the main control center. The GMS handles the unregulated generation portion of FE's business, including performing automatic generation control (AGC), wholesale transactions, and evaluating fuel options for its generators. The facility also provides the load following ancillary service for FE and has the responsibility for maintaining FE's area control error (ACE). On August 14, the GMS control center was responsible for calling for automatic reserve sharing to replace the 612 MW from the loss of East Lake Unit 5.

The energy management system (EMS) control center monitors the entire FE control area and is separate from the GMS facility. A director of transmission operation services is in charge of the overall control center. The director oversees two groups: one is responsible for real-time operations and the other is responsible for transmission operations support called "setup." The setup group has several dispatchers who conduct day-ahead studies in a room across the hall from the control room.

The real-time operations group is composed of two groups: control area operators and transmission operators. Each group has two positions that are staffed 24 hours a day, and there is always a supervisor present with direct control over both groups. The supervisors work eight-hour shifts (0700–1500, 1500–2100, 2100–0700), while the operators work 12-hour shifts (0600–1800, 1800–0600). The transmission operators are in the main control room and have the responsibility of maintaining the reliability of the transmission system. The control area operators are in a separate room across another hall and are responsible for overseeing Conversion Economics and directing restorations efforts.

Within the main control room are two consoles for the transmission operators. These are designated as the Western Desk, which oversees the western portion of the system, and the Eastern Desk, which oversees the eastern portion of the system. Each desk has one or two operators. There is also a desk for the supervisor in the back of the room and one or two other desks for operators who are performing relief duty.

FE also maintains several regional control centers that are responsible for monitoring the 34.5 kV and 23 kV distribution systems. These remote consoles are part of the overall GE/Harris EMS system and represent some of the remote console failures reported by FE.

FE operators have power network analysis (PNA) applications available that include network configuration, state estimation, contingency analysis (both real-time and study mode), and power flows. According to FE's chief information officer (CIO), the state estimator is scheduled to run every 30 minutes, was running on August 14, and can be run on demand by the system operator. The solved state estimator cases are not automatically saved. The CIO stated that the state estimator convergence was better than 90%. FE also has a dispatcher training simulator (DTS), but the CIO did not know if the DTS was used by the system operators on August 14, or in general.

Interviews with FE system operators revealed that these tools were used infrequently, with the exception of evaluating upcoming scheduled outages in a day-ahead mode. Further, the dispatchers reported that the contingency analysis didn't work well in the real-time mode. They reported having trouble with this application ever since the EMS was installed in 1995. For many contingencies, they would end up getting 10 to 15 limit violations for line flows and low voltages. The same violations would continually show up on all the lines. In the opinion of the operators, the contingency analysis was producing too many alarms and, as a result, was not being run in the real-time mode.

According to the CIO, the FE EMS has a distributed redundant architecture, which means that the company's EMS seldom fails. When it does fail, system operators can either do a warm start (rebooting the computers with retained data) or a cold start (rebooting the computers with no retained data). Performing a cold start takes at least 20 minutes if everything goes well, but longer if it doesn't. The EMS last had a warm start on July 11, 2003, and a cold start in December 2002.

FE does not operate a redundant back-up control center. In the event of a loss of the primary control center due to fire, failure of computer or other systems, or other disaster, the plan for operations is to send personnel to their critical substations and operate the system by telephone from some other location.

The FE control room resembles an office setting. The room does not have a map board of the system, either dynamic or static, nor is any other large-scale representation of the system available. A map board that did exist was removed in 1995. The operators did not consider this a handicap because the information they needed was available on their computer screens; each operator had two or more monitors that had several windows open on them. Investigators found that the operators utilized the alarm screens as their primary tool and that they did not display an overview of the system on their computer screens. One operator reported that he has three monitors at his console and has six to seven windows open on each screen. He also has two computers on his desk and normally has the system summary page open since it shows the system frequency, control area load, and ACE.

FE system operators were primarily provided with on-the-job training. Interviews with the operations staff revealed that no one was in charge of operator training, although one individual had been in the past. Further, many of the operators stated that it had been several years since they had any training on use of the PNA and could not remember having any training on the PNA applications within the PNA. Some reported never having completed training on the DTS and noted that the DTS is primarily used to test new software. One operator reported it had been two and a half years since his last training of any kind.

Overview of the Events of August 14, 2003

FirstEnergy[1]

Conditions Leading up to Chamberlin-Hardin 345 kV Line Trip at 1505[2]

There is unanimous agreement from all FE operators, and indeed all operators in the Midwest, that August 14 was expected to be a normal, late-summer day. It was expected to be hot, but not exceedingly so. Electric loads were expected to be high, but not at peak levels. Significant interregional power transfers were expected, including power sales into ECAR, Ontario, PJM, and New York, but nothing beyond what system operators had seen many times that summer.

As the day progressed, the FE operators continued to operate on the assumption that it would be a normal day. Voltages in the FE territory were low compared to other systems, but the FE operators agreed that they had seen voltage levels as low as they were on August 14 and the voltages were not "particularly bad." FE operators spent a good deal of time that morning requesting additional reactive support from the plants under their control as well as attempting to return some 138 kV capacitor banks to service that had been taken out of service for routine maintenance.

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[1] Information in this section is derived from interviews with FE personnel and system operator transcripts.

[2] All times are eastern daylight time, unless otherwise noted.

Tripping of East Lake Unit 5

One of the most critical resources to the Cleveland area on August 14 was East Lake Unit 5 (597 MW rated). Due to the loss of East Lake Unit 4 the previous day and because of increasing system loadings, this unit and the Perry nuclear unit were among the most critical resources in the Cleveland area. Throughout the morning, the EMS operators were calling the FE plant operators to request an increase in reactive power. A significant conversation took place between the FE EMS (system control center) operator and the East Lake Unit 5 operator at approximately 1316 on August 14.

`EMS Operator:`	`Hey, do you think you could help out the 345 voltage a little.`
`East Lake 5 Operator:`	`Buddy, I am -- yeah, I'll push it to my max max. You're only going to get a little bit.`
`EMS Operator:`	`That's okay, that's all I can ask.`[3]

As shown in *Figure 5*, the operator did make such an adjustment. The MW output for East Lake Unit 5 had been regulating around 600 MW all day with only about 30 MW variations. From early morning, the Mvar output had been steadily climbing higher and higher as the system required increasing reactive power to support the scheduled voltage. At about 1030, it appears that the operator had made a slight upward adjustment and recalibrated the set point of the automatic voltage regulator (AVR).

The effects of the operator trying to go to “max max” at 1316 are apparent on the chart. The reactive output rose above the rated maximum for about four minutes and a slight step increase in the reactive output of the unit was achieved. Investigators believe this increase correlates with the trip of a 138 kV capacitor bank in FE’s system. The reactive output remained at this level for another three to four minutes and then tripped off AVR to manual operation and a set point that effectively brought the gross Mvar output to zero.

When a unit at full load trips from AVR to manual control, normal practice is to decrease the exciter to its rated full load DC field current or a reasonable preset value; the Mvar output should not be designed or set to decrease the Mvar output to zero. As *Figure 5* shows, about four to five minutes after Mvar output decreased to zero, the operator increased the terminal voltage and attempted to go back on AVR when the excitation system tripped altogether. The unit was then tripped off by a loss-of-excitation relay. Later recorded conversations indicated subsequent trouble with a pump valve that would not reset after the trip. As a result, the unit could not be quickly returned to service.

The excitation system failure resulted in the loss of East Lake Unit 5 and operators failed in their attempt to increase the supply of reactive power in the Cleveland area. There was no coordinated effort by the FE system operators to increase the scheduled voltage in the area to increase the voltage on FE’s system. The result of increasing the reactive output of the East Lake Unit 5 was a corresponding decrease in reactive output of neighboring generating units as shown in *Figure 6*.

At no time during the morning or early afternoon of August 14 did FE operators indicate that they were having voltage problems or request any assistance from outside the FE control area for

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[3] FE System Operator Transcripts

voltage support. MISO, FE's reliability coordinator, did not monitor voltage and left that function up to their members to monitor and report any problems. Further, FE did not report the loss of East Lake Unit 5 to MISO.

Figure 5 — East Lake Unit # 5 MW and Mvar Output and Voltage

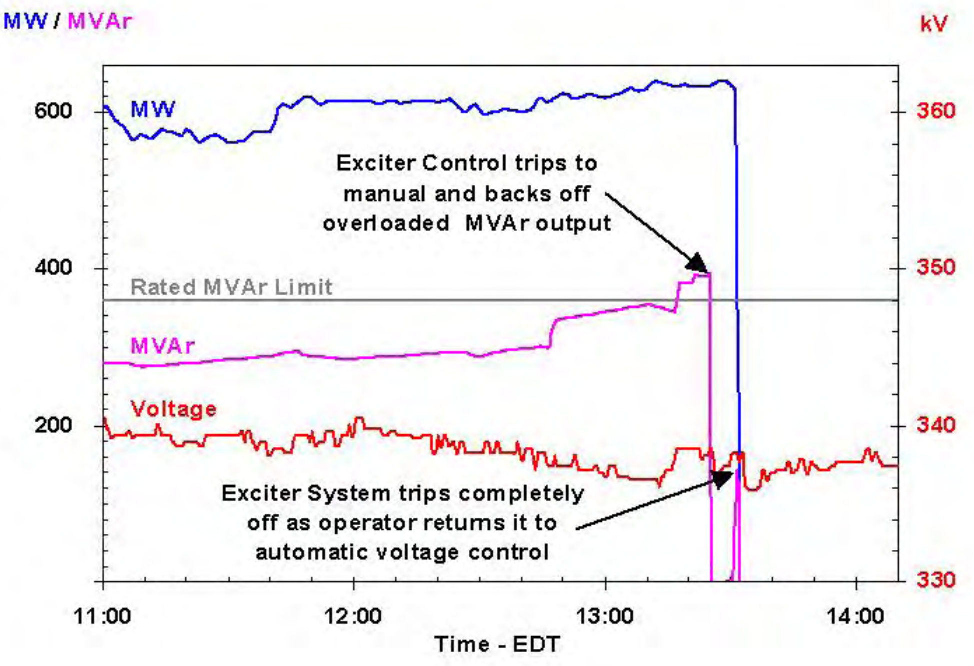
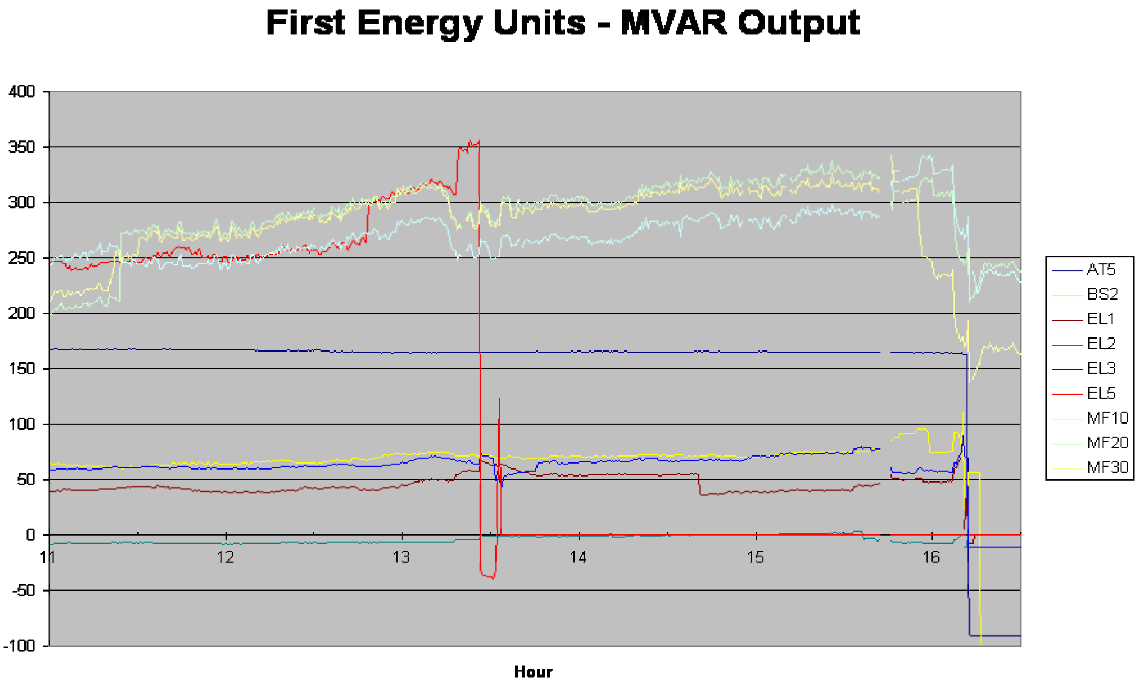


Figure 6 — Reactive Output of FirstEnegry Generating Units



Investigators found that FE operators were not adequately trained on the impacts of adjusting generator reactive output. In particular, they were not trained in pushing the units beyond stated limits, providing appropriate transfer from automatic to manual excitation set points, the need for coordinating voltage schedules, and resulting AVR settings of generating units.

Following the removal of significant pieces of equipment from service, system operators are required to evaluate their system to determine if the system remains in a safe operating state. The primary tools used for such determinations are the PNA tools mentioned above. On August 14, neither FE nor MISO undertook such an analysis following the tripping of East Lake Unit 5. Had such an analysis been completed prior to 1505, the time of the Chamberlin-Harding 345 kV line trip, operators would have known that while the system remained in a stable state, certain components would be very near their limits if there were additional line or generator outages.

See Recommendations 1, 4, 5, and 7

Loss of Alarm Processing at FirstEnergy

Sometime shortly after 1414, the FE EMS system experienced a software failure that resulted in the loss of alarm processing. Following this event, FE system operators did not receive any alarms even though there were routine events taking place that should have generated alarms. Control room operators received no indication that the alarm processor had failed, beyond the fact that they were not receiving any new alarms from the system. With the number of alarms system operators normally received on an August afternoon, it is hard to understand how a system operator would not notice the absence of alarms. The system operator on duty that afternoon noted that they normally get a lot of alarms during the day, but he didn’t notice an absence of audible alarms during this time period.

Data continued to come into the control center and the events for the alarm processor began to cue up in the computer system. The resulting overload caused both the server supporting the application and the backup server to fail.

FE system operators relied almost exclusively on audible and on-screen alarms, plus alarm logs, to reveal any significant changes in system conditions. When FE’s alarm system failed, both audible and text alarms were no longer being presented to the system operators. Although additional information about system status was available in other displays, investigators did not see any overview displays of the system that were normally visible to the operators. And, because there was no map board available to provide wide-area grid visibility on a continuous basis, the operators had no broad view of the system.

FE information technology (IT) support personnel attempted to reboot the servers supporting the EMS application. Even though some reboot attempts were successful, the IT staff did not directly contact the system operators to confirm that the software applications running on these servers were operational. Such an action would have alerted the system operators to the failure of the alarm processor.

The key events related to the loss of the alarm process are shown below:

1414 Alarm logger fails and operators are not aware of Star-South Canton 345 kV line trip and reclose at 1427.

1441 EMS server hosting the alarm processor and other functions fails and the backup server takes control – IT staff is auto-paged.

1454 Backup alarm server fails. The EMS continues to function but with a long refresh (59 second). Select EMS data sent normally to others via inter-control center protocol; however, no control room operator (FE or MISO) identified the Chamberlin-Harding 345 kV line outage at 1505. This outage remained undetected for the remainder of the day.

1508 IT warm reboot of EMS appears to work but alarm processes are not tested and are still in a failed condition.

See Recommendations 1, 2, 4, and 7

Operator Shift Change at 1500

FE system operation supervisors work eight-hour shifts; one shift ends at 1500. When the supervisor for the East Desk left at 1500, he reported to the relief supervisor that there had been remote console failures at the southern and western regional control offices; the relief supervisor did not appear to find this unusual. The departing supervisor also informed the relief supervisor that the load was close to normal that day and was at an expected level, approximately 11,000 MW, maybe a little higher. He noted that it didn't seem to be too bad of a day, maybe a "little hot." He also informed the relief supervisor that, just before he had arrived, the Star-South Canton 345 kV line had tripped at the AEP South Canton end only and had been restored to service. The relief supervisor reported wondering why the line would have tripped only at one end, because 345 kV lines practically always trip at both ends, but he did not pursue it. The departing supervisor restated that at the end of his shift he thought that it had been a "real good day."

See Recommendation 4

Operations Following the Chamberlin-Harding Line Trip and Prior to Sammis-Star Line Trip

The first major transmission line outage to occur in the Cleveland area on August 14 was the Chamberlin-Harding 345 kV line at approximately 1505. This line, which was loaded at substantially below its rating, tripped due to a tree contact. Following this event, a number of other lines tripped, which culminated in the trip of the Sammis-Star 345 kV line at approximately 1606. During this same hour, FE lost its alarm indication, the primary method for monitoring its system. During this time, the only avenue FE operators had to determine what was happening on their system was from the communications that took place between FE EMS operators and other system operators.

Many telephone conversations took place between system operators on August 14. The FE operators were so dependent on alarms to provide an indication of the system's health that they discounted the information being provided from outside of their system. Further, there was a belief in the FE control room that something major was happening on the AEP system, not on FE's. To illustrate this perception, calls from AEP to the FE EMS system operators are summarized below.[4]

1432 AEP calls regarding trip and reclose of Star-South Canton. FE operator indicates no problems on FE end of line.

1519 AEP calls confirming Star-South Canton trip and reclose after sending personnel to South Canton substation. A ground fault relay target at South Canton was reported by AEP. Because FE line trip and reclose alarms did not occur at the Star substation, FE did not perform a field check for relay targets at the Star substation. The investigation team later discovered that the line had tripped and reclosed at both ends due to a ground fault. The ampere capability of the Star-South Canton line was fully compromised by a tree contact. At 1432, FE had begun to lose situational awareness, and led both AEP and FE operators to the conclusion that the line trip at South Canton was a "fluke" relay operation.

1535 The Mansfield 2 plant operator called expressing concern about generator fault recorder triggers and excitation voltage spikes as well as an alarm for over-excitation. A dispatcher also called reporting a "bump" on their system.

FE's Reading, Pennsylvania, control center called reporting that fault recorders in the Erie west and south areas had activated, wondering if something had happened in the Ashtabula-Perry area.

The Perry nuclear plant operator called to report a "spike" on the unit's main transformer. When he went to look at the metering it was `"still bouncing around pretty good. I've got it relay tripped up here … so I know something ain't right."`

FE Response — `"It's got to be in distribution, or something like that, or somebody else's problem … but I'm not showing anything."`

1536 MISO contacted FE regarding the post-contingency overload on Star-Juniper for the loss of the Hanna-Juniper 345 kV line. The system supervisor at FE reported in the interview that he did not recall hearing any audible alarms at the time. He also checked the unacknowledged alarm page and did not see any alarms. He then checked the alarm summary page but did not see any recent alarms. He said typically there could be "thousands" of alarms listed with the last alarm being at the bottom of the page.

1542 FE's western transmission operator informed FE's computer support staff that the EMS system functionality was compromised. "Nothing seems to be updating on the computers…. We've had people calling and reporting trips and nothing seems to be updating in the event summary… I think we've got something seriously sick." This is

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[4] FE operator transcripts and DOE field interviews.

the first evidence that a member of FE's control room operating staff recognized that their EMS system was not functioning properly. There is no indication that this operator informed any of the other operators at this time. However, the FE computer support staff discussed the subsequent EMS alarm corrective action with some control room operators shortly thereafter.

1542 The Perry plant operator called back with more evidence of problems. `“I’m still getting a lot of voltage spikes and swings on the generator…. I don’t know how much longer we’re going to survive.”`

1545 A tree trimming crew reported that they had witnessed a tree-caused fault on the Eastlake-Juniper 345 kV line. However, the actual fault was on the Hanna-Juniper 345 kV line in the same vicinity. This information added to the confusion in the FE control room, because the operator had indication of flow on the Eastlake-Juniper line.

AEP called after the Star-South Canton 345 kV line tripped a third time and locked out at 1542 to discuss and inform them that they had additional lines that were showing overloads. FE operators recognized then that the Star breakers had tripped and remained open.

1546 The Perry plant operator called the FE control room a third time to say that the unit was close to tripping off: “It’s not looking good…. We ain’t going to be here much longer and you’re going to have a bigger problem.”

1548 The FE transmission operator sent staff to man the Star substation, and then, at 1550, requested staffing at the regions, beginning with Beaver, then East Springfield. This action, 43 minutes after the Chamberlin-Harding line trip and 18 minutes before the Sammis-Star trip, signaled the start of the cascade. Chronologically, it was the first clear indication that at least one of the FE system operators was beginning to recognize that an emergency situation existed.

1556 PJM called FE to report that Star-South Canton had tripped and that PJM thought Sammis-Star was in emergency limit overload. FE could not confirm this overload. FE informed PJM that Hanna-Juniper was also out of service. At this time, FE operators still believed that the problems existed beyond their system, one of them saying, `“AEP must have lost some major stuff.”`

It is apparent that some FE operators believed that what was being reported was happening outside of their system. However, the manager of operations support services, who was also serving as the manager of control area and transmission on August 14, reported that at approximately 1545, the shift supervisor entered his office and said “seems like we’re losing the system.” Further, by 1545 the FE EMS control center was operating from its backup generator, which meant that power was out at the control center itself.

See Recommendations 4. 5 and 7

Control Room Communications

A review of the communications on August 14 at FE's main control room found numerous problems. Operator transcripts indicate that in addition to control room business, numerous personal and customer calls came into the transmission operations center. The volume of telephone calls kept the operators very task-oriented and impaired their ability to view the larger picture. Further, communications between operators, between operators and support staff, and between operators and management were not effective. For example, one operator reported that as the voltages were falling throughout the afternoon, his job was to monitor the tie lines and make sure that the generation plants met their voltage schedules. He indicated some of the plant operators in the northern part of their system were saying they couldn't raise the voltage because they were maxed out on VArs. However, he indicated that he was not required to tell anyone if there were voltage problems, and he did not discuss the problems with his supervisor or with MISO.

See Recommendation 5

Operator Actions

As shown above, FE system operators took few actions to prevent disturbances on the system from spreading. The interviews revealed that the manager then attempted to contact the director of transmission operations services, who was at a meeting at FE headquarters in Akron. He tried unsuccessfully to contact him by cell phone and then by pager at 1601.

After paging the director of transmission operations services, the manager returned to the control room. He believed that the Hanna-Juniper line tripped while he was out of the control room, because when he returned he heard dispatchers talking on the radio about that line being "in the tree." He then noticed a cascade of problems and realized that the system operators were not getting alarms. Someone then asked him to call the president of FE and let him know that they had lost the system and that it would be one or two days, perhaps more, before it could be fully restored. FE then began the restoration effort.

One of the key components of responding to a system emergency is the appropriate delegation of duties and the coordination of activities. There are several instances where that delegation and coordination did not occur at FE.

- Upon realizing the magnitude of the problem, the shift supervisor left the control center to inform his manager of the problem, rather than calling or sending someone else as a messenger. Also, upon his departure, he gave no instructions to either the eastern or western region controllers about how they should proceed.
- The eastern region dispatcher stated that he was overwhelmed with phone calls from customers during this time and was too busy answering phones to do anything else.
- Personnel were recruited from other divisions to help out in the control room, including set-up and technical support personnel. However, some stated that they had no clearly defined roles to play in the control room. They merely stood in the back of the room and observed or grabbed a note pad and started writing things down.
- One set-up dispatcher, who worked in another area and was unfamiliar with all the events that occurred in the control room, went to his office to call MISO. His intentions were to

gather information from MISO to give to the supervisor in the control room. However, this call simply created confusion for MISO, because MISO staff had called FE earlier and were waiting to hear back from FE about the nature of the problem. MISO personnel became further confused and frustrated because they received a call from an FE employee who admittedly had "no clue" as to what was going on.

- When the shift supervisor returned to the control center with the manager, the manager became aware of the magnitude of the problem. He stated that his first thought was "who do I need to call" for help. He admitted that he gave no consideration to remedial action such as load shedding or even running a contingency analysis to address the crisis on the system, which had become apparent to everyone in the control room by this time.

See Recommendations 2, 4, 6, and 7

The Use of Load Shedding as a Possible Action at FirstEnergy

The FE system operators never considered direct load shedding at any time during the events leading to the cascading outage as a possible action to preserve system stability. FE reported that it has an emergency load-shedding plan on file with the Public Utilities Commission of Ohio. However, the plan, which consists of rotating blackouts, contemplates a capacity problem. The management's consensus was there wasn't much an operator could do in the five-to-ten minute time frame.

According to the FE control room manager, it takes two hours to get people into position to shed load and he felt it was far too early to take the actions necessary to establish a process to shed load. He indicated that studies would be required to determine that shedding load would actually help. FE indicated it had limited immediate load shedding capability on parts of its system, but not in the Cleveland area.

MISO management reported that on August 15, a similar situation to the one that occurred on August 14 developed in the FE control area. In order to get the Hanna-Juniper flow reduced, MISO directed FE to immediately shed 500 MW of load. From the time MISO issued the order, it took FE about 60 to 90 minutes to implement it, eventually shedding 400 MW of firm load customers. This was the first time MISO had ever ordered a control area to shed load.

See Recommendations 4 and 7

Overview of MISO Reliability Coordinator Operations[5]

MISO is the reliability coordinator for a region of more than one million square miles. MISO provides reliability coordination from two offices: one in St. Paul, Minnesota, and one at its headquarters in Carmel, Indiana. The St. Paul office provides reliability coordination for members of the Mid-Continent Area Power Pool (MAPP).[6] Some MAPP members belong to MISO and some do not. The Carmel monitoring zone provides reliability coordination services

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[5] The information contained in this section is based on interviews with MISO personnel by the DOE field investigation team.

[6] MAPP has since been replaced by the Midwest Reliability Organization.

for the remainder of the MISO area and is the primary reliability coordinator for MISO. The U.S. Department of Energy (DOE) investigation team visited the Carmel office, which is the focus of this section.

MISO uses a flowgate monitoring tool to manage its system. This tool monitors groups of transmission lines based on line outage distribution factors (LODFs) and power transfer distribution factors (PTDFs). These are updated based on the information contained in the NERC Interchange Distribution Calculator using data that is supplied via the NERC System Data Exchange (SDX). This data on line outages is required to be updated by the reliability coordinators at least daily.

MISO receives data from all of its member transmission owners and others as requested. This data comes from not only the MISO area but from surrounding areas as well. However, this data was not mapped into a topology processor or a system that could provide an overview of the system status beyond the flowgate monitoring tool.

On August 14, MISO did not have a functioning supervisory control and data acquisition (SCADA) control system in place, nor did it have a fully functioning state estimator or contingency analysis package. Because these tools were under development, they were not used by the reliability coordinators to monitor all elements of the system. Without these tools, MISO did not have the capability to monitor all transmission system parameters on August 14.

Prior to August 14, the MISO reliability coordinators were told to be aware of the voltages on the system but weren't given tools to really monitor them. MISO's management emphasized that the responsibility for monitoring voltage is not specified in the NERC requirements for reliability coordinators. MISO's manager for area reliability coordination noted that MISO had started without a state estimator and NERC standards did not require one.[7]

As the reliability coordinator, MISO relied on the monitoring capabilities of the control areas. Problems that were reported to MISO were primarily addressed through the use of transmission loading relief (TLR) procedures, including reconfiguration of the transmission system and redispatch of generation if necessary as determined by off-line studies. MISO did have the authority to order the control areas to shed firm customer load if necessary. However, MISO had no formal procedures in place with FE to implement load shedding.

On August 14, two reliability coordinators were on duty at the Carmel office to cover the eastern portion of MISO – a primary reliability coordinator and a secondary reliability coordinator – along with a number of certified operators or engineers for operations support. MISO typically hired experienced system operators from local transmission owners and control areas to be its reliability coordinators. While MISO provided some training to its reliability coordinators, it had no formal training program in place.

See Recommendations 1, 2, 3, 4, 5, 6 and 7

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[7] NERC Operating Policy 9 requires reliability coordinators to have "detailed monitoring capability of the reliability area and sufficient monitoring capability of the surrounding reliability areas to ensure potential security violations are identified," NERC Operating Policy Manual, Appendix 9D – Version 3.

MISO — Events of August 14, 2003

MISO reported that based on studies of the system, its operators expected a fairly normal August day. However, events on the system in the morning caused MISO to change its outlook. The day had started out for MISO with numerous other system problems to manage, all of which had been brought under control by about 1100. The outage of Cinergy's Columbus-Bedford 345 kV line and subsequent outage of Cinergy's Seymour-Airport Road 138 kV line and the Bloomington-Denois Creek-Columbus 230 kV line around 1200 brought the next challenge for MISO reliability coordinators, along with some flow problems on the Ghent-Batesville 345 kV line in southeastern Indiana. The loss of these lines required the full attention of the MISO staff to implement a redispatch of generation in southwestern Indiana. The primary reliability coordinator indicated that everyone at MISO was focused on the Cinergy problem at midday.

Additionally, the MISO reliability coordinator reported that MISO spent a significant amount of time each hour reissuing TLRs for the next hour. This task must be started at about 25 minutes after each hour, and may take 10 to 15 minutes to complete. The secondary reliability coordinator helped with this task.

MISO was not aware of the outage of the Chamberlin-Harding 345 kV line, even though MISO received data from FE every 30 seconds. The MISO reliability coordinator indicated MISO could get 700 to 800 alarms per day for planned work and that circuit breaker alarms are not grouped by transmission line. Rather, they are listed by substation, kV, and a four-character breaker ID. MISO personnel indicated it is time consuming to correlate the breaker operations with an actual transmission line. In this situation, they simply missed seeing the Chamberlin-Harding alarm. Because these circuit breakers were not linked to a line outage map board or other dedicated display to provide wide grid visibility, no one at MISO knew this line was out until after the blackout occurred.

Shortly after 1530, the MISO reliability coordinator, through the flowgate monitor tool, saw that an FE flowgate was at 108% of its rating. This was an outage transfer distribution factor flowgate, number 2,265, which monitors the flow on FE's Star-Juniper 345 kV line for the contingent loss of the Hanna-Juniper 345 kV line. The actual contingency overload would have been greater because the Chamberlin-Harding 345 kV line was out of service and not updated in the calculation for the flowgate monitors' outage transfer distribution factor. The normal MISO procedure is to contact the affected control area to verify that the problem MISO identified represents actual system conditions, because the flowgate monitor may not reflect actual system conditions. The MISO reliability coordinator immediately contacted FE about the situation, but FE could not confirm the contingency overload on Hanna-Juniper.

MISO's ability to see the voltages and other parameters in northeastern Ohio were limited. MISO had started to build SCADA one-line diagrams for that part of the system, but none of the one-lines were populated with data. There were some state estimator system (RTNET) displays for northeastern Ohio, but the topology process was not yet available to support node-breaker displays. This meant that MISO operators needed to review each breaker status point to determine if a line had tripped.

Because much of the data from non-MISO areas was not mapped into a topology processor, MISO was not fully aware of the generators and line outages in FE's control area. Without direct knowledge of the system conditions, MISO was unaware of the status of the system and thus could and did not direct any actions to correct the situation before the system deteriorated further.

MISO State Estimator and Contingency Analysis Tools

MISO management stated that MISO is only charged with monitoring key facilities as defined by the flowgates in its flowgate monitoring tool. They said that MISO's RTNET application was being driven by the start of market operations, which was targeted for March 2004. Using RTNET and other tools, MISO said it was planning to have the ability to directly dispatch generation but did not have that ability on August 14.

MISO reliability coordinators often used the state estimator to analyze the health of the system. On August 14, there were three separate incidents when the state estimator did not solve or solved with a large mismatch.

The first incident occurred earlier in the day during the Cinergy transmission line outages. The state estimator was not solving or solved with large mismatch for 45 minutes during this first incident (1215–1300).

The second incident occurred between 1307 and 1444, when the state estimator automatic trigger was disabled. The EMS engineer, as a standard procedure to troubleshoot the state estimator problems that had occurred earlier, had disabled the trigger and did not re-enable it until 1444. However, at 1402, the Stuart-Atlanta 345 kV line tripped. Even if the trigger had been enabled for the entire period, the state estimator would have solved with large mismatch beginning at 1402. Not having the trigger enabled prevented good state estimator solutions between 1307 and 1402 (55 minutes).

The third incident occurred between 1444 and 1534. The state estimator attempted to solve four times and each time it either failed to solve or solved with a large mismatch. An EMS engineer found that the status of the Stuart-Atlanta 345 kV line was not available to the state estimator. The engineer found that by opening this line, the state estimator would solve and he was able to complete two successful runs.

Real-time contingency analysis (RTCA) was disabled while troubleshooting the problem and there were no RTCA runs made from these two valid state estimator solutions. The operations engineer indicated that the Stuart-Atlanta line was still in service (no outage report had been entered into SDX). After the EMS engineer closed this line back into service, the state estimator solved with a large mismatch for two consecutive runs.

The operations engineer was asked to confirm the status of the Stuart-Atlanta line. In an initial call to the PJM operator, he was unable to confirm the status of the line. In a return call, PJM confirmed the line was open. The EMS engineers opened the line again in the state estimator and achieved a valid solution. (Before the line was opened, the state estimator did not solve or solved with large mismatch for 50 minutes during this third incident.) A valid solution was achieved at 1534, which had an RTCA run completed at 1541. Based on the timing of this solution, the investigators believe the solution contained the loss of the Stuart-Atlanta 345 kV line, the Eastlake 5 generator, and the first FE line that tripped (Chamberlin-Harding 345 kV).

Because this was only the first valid state estimator solution, a manual trigger was used to start RTCA. A second valid solution was achieved at 1543. There was no manual trigger of RTCA at this time and the automatic trigger did not occur because three consecutive valid state estimator solutions are required for the automatic trigger. A third valid solution was achieved at 1557, which had a RTCA run completed at 1604. Based on the timing of this solution, it is believed this RCTA contained the loss of the lines and generators in the earlier run plus the second and third FE lines that tripped (Hanna-Juniper 345 kV and Star-South Canton 345 kV). This left the state estimator and RCTA without solutions between 1444 and 1534 (50 minutes). Table 2 shows the timeline for the state estimator runs.

Table 2 — Status of MISO State Estimator and Contingency Analysis

1215	Cinergy's Bloomington-Denois Creek line outage results in state estimator large mismatch as the topology processor does not include this line for mapping into the state estimator or other MISO applications.
1235	MISO senior EMS engineer notices that its state estimator program has solved with a mismatch.
1240	MISO engineer checks the state estimator program, and does not find anything obviously wrong. He disables the periodic trigger, a program feature that causes the state estimator to run automatically every five minutes. He determines that the mismatch was caused by the model depicting Cinergy's Bloomington-Denois Creek 230 kV line as being in service when it was physically out of service.
1255	MISO senior EMS engineer takes the Bloomington-Denois Creek line out of service in the model.
1300	The MISO state estimator model now solves and a valid solution is given.
1307	The state estimator periodic trigger is still disabled; the RTCA program is manually run along with a second manually triggered run of the state estimator.
1330	Everything looks good, the MISO senior EMS engineer leaves for lunch, leaving the state estimator periodic trigger disabled.
1345	While out to lunch, the MISO senior EMS engineer should have received a page from an internally developed pager software program that would have indicated that the state estimator was not providing new solutions. This software runs on the desktop of a co-worker who turned it off because the co-worker required substantial CPU capacity to conduct his work. The MISO senior EMS engineer remains unaware that he forgot to turn the state estimator automatic trigger back on.
1440	The senior EMS engineer returns from lunch, operations staff had been looking for him to figure out why the state estimator is not running every five minutes as it normally does.
1444	The senior EMS engineer activates the periodic trigger and manually runs the state estimator program and gets a mismatch.
1508	The senior EMS engineer concludes that the state estimator got a mismatch due to a line outage. He believes the mismatch was caused by an outage of the Stuart-Atlanta 345 kV line (which according to the timeline tripped about an hour earlier at 1402). He takes the Stuart-Atlanta line out of service in the state estimator and gets a valid solution.
1509	The senior EMS engineer then goes over to the control room to tell the operators that he thinks the Stuart-Atlanta line is out of service. Control room staff refer to their Outage Scheduler and tell the senior EMS engineer that the Stuart-Atlanta line is "up" (based on SDX data) and should be depicted as in service in the state estimator model.

1517	The senior EMS engineer tries to run the state estimator model with the Stuart-Atlanta line up and running, but the model again shows a mismatch.
1534	At the request of the EMS engineer, operators called PJM and confirmed that the Stuart-Atlanta line was out of service. The senior EMS engineer adjusts the model and comes up with a valid solution.
1541	RCTA is completed manually. Based on the timing of this state estimator solution, investigators believe it contained the loss of the Stuart-Atlanta 345 kV line, the Eastlake 5 generator, and the first FE line that tripped (Chamberlin-Harding 345 kV). Since this was only the first valid state estimator solution, a manual trigger was used to start RTCA.
1543	The second valid state estimator solution is completed. No RTCA is completed.
1557	The third valid state estimator solution is completed.
1604	RCTA is completed.

Actions Taken by MISO

Due to a lack of knowledge of the system conditions, MISO did not take any actions to preserve the reliability of the system consistent with its reliability coordinator responsibilities. Had the state estimator and contingency analysis tools been functional or had an overview of the actual system depicting the transmission lines that were tripping been provided, MISO could have taken corrective actions. However, without proper emergency response training of the reliability coordinators, the likelihood of their taking appropriate actions remains small. One reliability coordinator said, “Who could prove shedding load had just prevented a major East Coast blackout? We’re damned if we do, damned if we don’t.”

See Recommendations 1, 2, 3, 4, 5, 6 and 7

Overview of American Electric Power Operations[8]

AEP’s transmission operations are divided into two groups: transmission and control area operations. AEP transmission dispatchers issue clearances, perform restoration after an outage, and conduct operations such as tap changing and capacitor bank switching. They monitor all system parameters including voltage. AEP control area operators monitor ACE, maintain contact with the reliability coordinator (PJM), implement transaction schedules, watch the flowgates, and change generator excitation to control voltage and var flows. AEP maintains and operates an EMS complete with a state estimator and on-line contingency analysis that runs every five minutes.

American Electric Power — Events of August 14, 2003

On August 14, AEP operators were aware of many of the events that were occurring in northeastern Ohio. In particular, AEP dispatchers were aware of the transmission line outages on their tie lines with FE. AEP did not have operational control of the FE portion of these tie lines and could not have taken unilateral actions to open or close these lines. The transcripts indicate that AEP operators made numerous phone calls to FE, PJM and MISO, and appeared to be

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[8] The information contained in this section is based on interviews with MISO personnel by the DOE field investigation team.

looking to the MISO and PJM reliability coordinators to take some actions to address the developing situation.

Beginning with the first trip of the Star-South Canton line, AEP contacted FE to verify the trip. Later, AEP's state estimation and contingency analysis tools indicated a contingency overload for the Star-South Canton line and attempted to implement a reduction in loading through the TLR procedure with PJM. This conversation lasted six minutes and demonstrated a good deal of confusion on the part of PJM. Before the TLR could be implemented, the line tripped. The events occurring within AEP are covered below in the conversations between AEP and PJM operators.

See Recommendations 5, 6 and 7

Overview of PJM Interconnection Operations

PJM serves as a control area for both the original PJM footprint and the area added by the expansion of PJM to include Allegheny Energy. PJM also serves as the reliability coordinator for AEP, DPL, Duquesne, and Commonwealth Edison (ComEd), with plans to integrate all of these systems into the PJM market. The focus here is on PJM as a reliability coordinator.

PJM reliability coordination is centered in its Valley Forge, Pennsylvania, headquarters with two operating centers, one in Valley Forge (PJM-East) and one in Greensburg, Pennsylvania. (PJM-West). The PJM-East shift supervisor is the reliability coordinator for PJM, AEP, Allegheny, DPL, Duquesne, OVEC, and ComEd. There are two open video/audio live links between the east and west control centers that provide connectivity and presence between the two control centers. When in training, operators are moved between all of the desks in both Valley Forge and Greensburg. At the time of the blackout, ComEd was being monitored from MAIN's Lombard, Illinois, control center as the ComEd territory had not yet been integrated into PJM.

PJM does not have direct control over any generating facilities other than the ability to send price signals directly to generators for AGC. PJM exercises control over the power systems within its footprint by telephoning local transmission dispatch centers. A monitoring zone had existed in Groveport, Ohio (the former ECAR-MET reliability coordinator office operated by AEP), but it had been consolidated into the Greensburg site. To accomplish this consolidation and to ensure visibility of the system, the Greensburg site initially included terminals from the Groveport and Lombard system monitoring tools. PJM planned to fully integrate these systems into the PJM tools to allow for full market integration using locational marginal pricing and to allow for state estimation and contingency analysis. Both the Groveport and Lombard monitoring tools had state estimation and contingency analysis capability.

PJM was operating under a NERC-approved reliability plan in October 2002. In that plan, PJM indicated that from December 2002 until April 2003, it would use three different systems to monitor the three separate areas: PJM, ECAR-MET, and MAIN. Each of these systems were providing security assessment and monitoring as separate reliability coordinators. The PJM reliability coordinator would be able to monitor all three systems at the Valley Forge control center and back-up control center. After April 2003, the ECAR-MET system would be replaced with the PJM system. On August 14, the Groveport system had not been fully integrated and

PJM relied on remote terminals installed in its facility from Groveport to monitor the Ohio system.

PJM — Events of August 14[9]

Conditions on PJM's system were considered to be normal on August 14. Voltage was a concern as it is on any other high load day, and PJM had taken normal and appropriate actions to ensure adequate voltage support across its system. The following is constructed from interviews with PJM staff by the DOE on-site teams and from the operator transcripts of PJM conversations on August 14.

1530 MISO called the PJM-West desk asking for information about a trip and lockout on the Stewart-Atlanta line (DPL line southwest of PORTS). The PJM-West dispatcher called DPL and verified the line was out of service and called MISO back.

DPL is part of the PJM system. However, the PJM control center monitoring system had no indication that the DPL line was out of service. It does not appear that there were any alarms or protocols for communicating such an outage to the PJM reliability coordinator, and state estimation and contingency analysis results following the loss of this transmission line were not reported by PJM.

1532 A digital fault recorder in the PJM portion of FE (Pennsylvania) showed an event in FE: the voltage at Erie was low. The PJM operator called FE and was told that a second line was out and that there were voltage problems at Erie. Low voltage during the day at Erie was unusual.

1535 PJM-West desk received a phone call from AEP regarding the South Canton-Star line.

This call lasted about six minutes. The following excerpts demonstrate the confusion among control center operators and their limited visibility of the system.

PJM Operator: Where specifically are you interested in?

AEP Operator: The South Canton-Star.

PJM Operator: The South Canton-Star. Oh, you know what? This is interesting. I believe this one is ours. …….

PJM Operator: that one was actually in limbo one night, one time we needed it.

AEP Operator: For AEP?

PJM Operator: For AEP, yes. I'm thinking. South Canton -- where'd it go? South Canton-Star, there it is. South Canton-Star for loss of Sammis-Star?

AEP Operator: Yeah.

PJM Operator: That's the one. That's currently ours. You need it?

AEP Operator: I believe. Look what they went to.

PJM Operator: Let's see. Oh, man. Sammis-Star, okay. Sammis-Star for South Canton-Star. South Canton-Star for Sammis-Star, (inaudible). All right, you're going to have to help me out. What do you need on it ..?

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[9] Information in this section is based on interviews with PJM reliability coordinators by the DOE on-site team, as well as from system operator transcripts.

AEP Operator: Pardon?
PJM Operator: What do you need? What do you need on it? How much relief you need?
AEP Operator: Quite a bit.
PJM Operator: Quite a bit. What's our limit? …..
AEP Operator: I want a 3-B.
PJM Operator: 3-B.
AEP Operator: It's good for 1,412, so I need how much cut off?
PJM Operator: You need like … 230, 240.
PJM Operator: Now let me ask you, there is a 345 line locked out DPL Stuart to Atlanta. Now, I still haven't had a chance to get up and go see where that is. Now, I don't know if that would have an effect.
AEP Operator: 1,341. I need -- man, I need 300. I need 300 megawatts cut.
PJM Operator: Okay. Verify our real-time flows on –

Summary: While the conversation between operators is appropriate and proper, it is clear from this conversation that the PJM reliability coordinator was not monitoring DPL and AEP facilities (areas for which PJM has reliability coordinator responsibility) in real time at the PJM center. Further, the operator had to leave the desk to determine where a 345 kV line was within the system, indicating unfamiliarity with the system possibly due to insufficient training regarding the AEP and DPL systems and a lack of visualization tools.

AEP Operator: What do you have on the Sammis-Star, do you know?
PJM Operator: I'm sorry? Sammis-Star, okay, I'm showing 960 on it and it's highlighted in blue. Tell me what that means on your machine.
AEP Operator: Blue? Normal. Well, it's going to be in blue, I mean -- that's what's on it?
PJM Operator: 960, that's what it says.
AEP Operator: That circuit just tripped. South Canton-Star.
PJM Operator: Did it?
AEP Operator: It tripped and reclosed….
AEP Operator: We need to get down there now so they can cut the top of the hour. Is there anything on it? What's the flowgate, do you know?
PJM Operator: Yeah, I got it in front of me. It is -- it is 2935.
AEP Operator: Yeah. 2935. I need 350 cut on that.
PJM Operator: Whew, man.
AEP Operator: Well, I don't know why. It popped up all of a sudden like that. …. That thing just popped up so fast.
PJM Operator: And … 1,196 on South Canton. Can you verify these? And 960 on -- South Canton-Star 1,196, Sammis-Star 960?
AEP Operator: They might be right, I'm –
PJM Operator: They were highlighted in blue, I guess I thought maybe that was supposed to be telling me something.

Summary: This is a proper conversation between the operators. However, it demonstrates that the PJM operator is not fully familiar with the monitoring system being used. The PJM operator is questioning the AEP operator about what something in blue on the screen represents, presumably because the AEP operator is more familiar with the system the PJM operator is looking at. This again indicates unfamiliarity with the tool possibly due to insufficient training regarding the tool itself.

AEP Operator: What's the flowgate on that again?

PJM Operator: 2935.

AEP Operator: Are you issuing it right now?

PJM Operator: Yes. I was hoping to verify the readings to make sure I'm not issuing this –

AEP Operator: Well, I'm showing 1,195 on right now. So that –

PJM Operator: 1,195 actual and 960 on the Sammis-Star line; that sound about right?

AEP Operator: I can't see FE's lines.

Summary: At this point the PJM operator is attempting to confirm flows on the system. However, the AEP operator is only responsible for the AEP system and cannot monitor lines within the FE system such as the Sammis–Star line. From this conversation, it is apparent there is a sense of urgency with the AEP operator since the line has already tripped and reclosed twice.

AEP Operator: Yeah, that says raw data, I’m not sure if those are right or wrong or what. Oh, jeez, there it just operated again.

PJM Operator: Is it operating?

AEP Operator: It's out.

PJM Operator: It's out? Okay, so we need a 3-B on –

AEP Operator: It just tripped out. Did you hear me?

PJM Operator: Yeah. Which one tripped?

AEP Operator: South Canton - Star.

PJM Operator: South Canton - Star. ….. Is the TLR going to do you any good at this point, then? Do you still need to get – is the TLR still going to cut the contingency South Canton - Star for the loss of Sammis-Star? A TLR on that, is that still going to -

AEP Operator: I'm not sure what's going to happen. You know what I mean?

PJM Operator: Yeah.

AEP Operator: Everything's changed.

PJM Operator: I don't think we have an actual setup for this.

Summary: During the discussion to implement the TLR, the transmission line tripped. The conversation continues to be focused on what to do with the TLR by the PJM operator.

AEP Operator: Well, there's other things tripping, too. That Torrey-Cloverdale.

PJM Operator: What is it?

AEP Operator: Looks like the Torrey-Cloverdale just tripped, too.

PJM Operator: Torrey-Cloverdale?

AEP Operator: Canton Central breakers --

PJM Operator: This is AEP?

Summary: The AEP operators are witnessing portions of the 138 kV cascade and relaying that information to the PJM operator. The PJM operator, as seen below, is looking at a state estimator screen and not real time flows or status of the AEP system; he is unaware of these line trips from his monitoring system.

PJM Operator: Sammis-Star, I'm still seeing flow on both those lines. Am I'm looking at state estimated data?

AEP Operator: Probably.

PJM Operator: Yeah, it's behind, okay. ….. You're able to see raw data?

AEP Operator: Yeah; it's open. South Canton - Star is open.

PJM Operator: South Canton - Star is open. Torrey - Cloverdale?

AEP Operator: Oh, my God, look at all these open...

PJM Operator to PJM control room: Get a hundred at least across all the units. Ronco still not where they should be, tell them to move down. (Inaudible.)

Male voice: We don't want that. We need to get 'em back down. I can't make? Do what I want? Backdown.

AEP Operator: We have more trouble . . .More things are tripping. East Lima and New Liberty tripped out. Look at that.

PJM Operator to PJM Control room: Thank you. I'll try to get'm [crosstalk].

A legitimate signal in a minute.

DPL lost a 345 kV too. I kid you not. (Inaudible.)

AEP Operator: Who's that?

PJM operator to PJM control room: Go to minimum. How far is that? I asked those questions in the wrong order, but -- yeah, that sounds good.

AEP Operator: Oh, my gosh, I'm in deep --

PJM Operator: You and me both, brother. What are we going to do? You need something, you just let me know.

AEP Operator: Now something else just opened up. A lot of things are happening.

PJM Operator: Okay. ….. South Canton - Star. Okay, I'm seeing a no-flow on that. So what are we overloading now? We lost South Canton - Star, we're going to overload Sammis - Star, right? ….. The contingency is going to overload, which is the Sammis - Star. The FE line is going to overload as a result of that. So I should probably talk to MISO.

AEP Operator: Pardon?

PJM Operator: I should probably talk to MISO because they're going to have to talk to FE.

Summary: The AEP operators continued to witness the 138 kV system cascade between their system and FE. The conversation ended at this point and PJM called MISO.

From the MISO operator transcripts from phone conversations, the PJM operator called MISO at 1555.[10]

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[10] 2003 08-14 CH22 Primary RC 1455 hours WAV.

PJM Operator: AEP, it looks like they lost South Canton – Star 345 line, and we are showing a contingency for that line and the Sammis Star line, and one of them lost the other. Since they lost that line, I was wondering if you could verify flows on the Sammis Star line for me at this time.

MISO Operator: Well, let's see what we I've got. I know that FirstEnergy lost their Juniper line, too.

PJM Operator: Did they?

MISO Operator: They are still investigating that, too. So the Star Juniper line was overloaded.

PJM Operator: Star Juniper.

MISO Operator: And they recently have got that under control here.

PJM Operator: And when did that trip? That might have –

MISO Operator: I don't know yet. I am still have -- I have not had that chance to investigate it. There is too much going on right now.

PJM Operator: Yeah, we are trying to figure out what made that one jump up on us so quick.

MISO Operator: It may be a combination of both. You guys lost South Canton-Star.

PJM Operator: Yes.

MISO Operator: And we lost Hanna to Juniper it looks like.

PJM Operator: Yes. And we were showing an overload for Sammis to Star for the South Canton to Star. So I was concerned, and right now I am seeing AEP Systems saying Sammis the Star is 1378.

MISO Operator: All right. Let me see. I have got to try and find it here, if it is possible and I can go from here to Juniper Star. How about 1109.

PJM Operator: 1109?

MISO Operator: I see South Canton Star is open, but now we are getting data of 1199, and I am wondering if it just came after.

PJM Operator: Maybe it did. It was in and out, and it had gone out and back in a couple of times.

MISO Operator: Well, yeah, it would be no good losing things all over the place here.

PJM Operator: All right. I just wanted to verify that with you, and I will let you tend to your stuff.

MISO Operator: Okay.

PJM Operator: Thank you, sir. Bye.

Summary: Although this conversation between operators is appropriate and proper, there is no sense of urgency and no discussion of actions to be taken to preserve the system as lines continued to open. The MISO operator provided some additional information about transmission line outages in FE, even though they were directly monitoring these facilities on August 14. The PJM operator indicated that the Star-South Canton line was out of service, but did not relay any of the information regarding the other lines that were reported as tripping by the AEP operator. The MISO operator did not act on this information and PJM operator did not press the issue.

By 1555 at the start of this PJM-MISO call, the overload on Sammis-Star exceeded 110% and continued to get worse. The overload had begun at 1542 after the Star-

South Canton line locked open. At 1605:57, just prior to tripping, fault recorder records show a Sammis-Star flow of 2850 amperes, or 130% of its emergency 2193 ampere rating. The line tripped due to a Zone 3 phase relay action. Although overloaded, the additional conductor sag did not cause a ground fault at 1605:57.

As the emergency was unfolding, MISO did not declare an emergency and FE was not requested to increase generation or shed load in the Cleveland-Akron area. Since FE had very little additional generation on-line or quick start combustion turbines in the Cleveland-Akron area, the only effective option was to shed load between 1541:35 and 1605:57 (24 minutes), prior to the loss of the Sammis-Star line. During the 138 kV cascade, approximately 600 MW of load was lost. However, FE SCADA software capability to shed additional large blocks of load within 24-minute period did not exist. If the emergency ampere overload on the Sammis-Star line had been reduced from 130% to less than 120%, the Zone 3 relay operation would not have occurred. This may have slowed down the cascade at this point, however, a 120% thermal overload would have continued to cause the line to sag, and the 345 kV voltages were decaying rapidly. Large block load shedding was needed to save the system from further degradation, but FE did not have the capability to do so.

See Recommendation 7

Conclusions

NERC and the industry have long recognized the need for improved reliability processes. This need was underscored on August 14. The three most important factors for ensuring reliability are worth repeating since all three of these factors, or the failure to properly implement them, played a role in the blackout. System operators must have: (1) a big-picture view of the system that includes operational information about the other control areas and regions in the interconnection; (2) the accountability and authority to implement emergency operations, including line load relief procedures and activation of shared operating reserves; and (3) agreement on common terminology, criteria, and standards for monitoring and operating the system. The blackout investigation identified additional areas where significant improvements are needed, including training, communications, and emergency operations.

Wide-Area System View

Effective and reliable system operations require a big-picture view or the ability to monitor a wide area of the system, along with large-scale visualizations to transform vast amounts of data into operable information. Reliability coordinators must be able to see a wide-area view beyond their coordination areas to effectively assess the health of the system. This involves more than monitoring flowgates for scheduling purposes. The reliability coordinator together with control areas (transmission operator) within its system must be capable of monitoring the same information and act as backup for each other.

Reliability coordinators should also be able to monitor critical facilities in neighboring reliability coordinator areas that could have an impact on the area. Such a monitoring capability would serve as an early warning system and would help to improve communications between the reliability coordinators. To effectively monitor the big picture, a reliability coordinator must monitor all facilities that, for the loss of the external facility, would or could affect facilities in the footprint for which a reliability coordinator is responsible and would require action by the reliability coordinator. This is considerably more challenging when the footprints of adjoining entities are not contiguous or are significantly intertwined.

On August 14, the PJM and MISO reliability coordinators were not adequately monitoring the surrounding systems. The affected control area operators had little visibility of the systems beyond their respective areas on August 14. The affected reliability coordinators did not have real-time monitoring capability of their entire systems or of the surrounding systems.

Accountability and Authority to Implement Emergency Operations

Reliability coordinators are responsible for overseeing the reliable operation of the area for which they have authority. There must be clear lines of responsibility and authority assigning responsibility for operating and monitoring specific portions of the system. On August 14, the responsibilities of the respective reliability coordinators were diluted and or unclear; and there was also a lack of clear responsibilities between the control areas and the reliability coordinators.

The reliability coordinator is responsible for managing reliability operations between control areas within their footprints as well as coordinating reliability actions with other reliability coordinators. Should a control area fail to fulfill its primary responsibilities to balance load and demand within defined system limits, it is the duty of the reliability coordinator to order the control area to take such actions as necessary to maintain a balanced and reliable system. On August 14, MISO did not have full monitoring capabilities or knowledge of both reactive and real power capabilities and loading within its region. Thus, MISO reliability coordinators were not able to fully understand what was happening within their system and were therefore not able to recognize or manage a system emergency. Ultimately, MISO relied on its members to tell it that there was an emergency.

Reliability coordinators also have a responsibility to each other to manage reliability issues at their seams. It is the responsibility of reliability coordinators to work with other reliability coordinators to resolve reliability-threatening events. When the PJM reliability coordinator attempted to inform the MISO reliability coordinator about an overloaded line within the MISO reliability coordinator footprint, the MISO reliability coordinator was unable to view that line in real time and was therefore unable to verify the information from the PJM reliability coordinator. The MISO reliability coordinator seemed unconcerned about the Sammis-Star overload problem, possibly because it was not a flowgate that MISO was expected to monitor. At no time did MISO recognize that an emergency was in progress.

When AEP initially called PJM as the reliability coordinator to request a TLR, there was some confusion as to whether or not the facilities in question were within the PJM reliability coordinator footprint. This was due both to an intricate and complicated seam between the PJM reliability coordinator and the MISO reliability coordinator, and the need for better operator training and integration of monitoring tools within PJM.

To ensure overall bulk system reliability, a second set of eyes is needed to effectively see the actions/conditions and direct corrective actions between control areas. FE expected that MISO was monitoring FE’s system because it was providing 30-second update data to MISO. MISO, however, expected that FE would contact it if there was a problem on FE’s system and required reliability coordinator oversight, particularly if it was voltage related. This clearly illustrates the lack of coordination between the control area and the reliability coordinator.

Monitoring the System

Observability is essential to the reliable operation of a high-voltage electric grid. This includes the facilities the electronic systems monitor and what operators can see, as well as the quality and timeliness of the information operators receive. While the power system is planned, constructed, and maintained to operate reliably under most stressed conditions, in real time any number of facilities such as transmission lines, generating plants and voltage support equipment can be out of service due to planned maintenance or because of unplanned outages that result in the loss of use of those power system lines and equipment. In addition to these factors, changing load and generation patterns cause system voltages and transmission loading to change.

Electronic monitoring systems and operators must have constant visibility of system conditions to detect abnormalities and respond with alarms or action. Further, events or conditions outside of a control area operator’s immediate system can have an impact on that system. This means that the system operator must be able to monitor beyond the borders of his/her own system; alternatively, there must be an entity with a wide-area view of control areas, which is the function that reliability coordinators are expected to provide.

To ensure observability, system operators and reliability coordinators must have the tools necessary to monitor the system in real time as well as the ability to make the necessary assessments to ensure that the system is continually in a safe operating state. The control area operator has primary responsibility for reliability within the area’s footprint. For both generation and transmission, the control area operator must monitor, know the limits of, and have absolute control of both real and reactive power within the area’s footprint. FE system operators did not have full monitoring capabilities or control of the generator real and reactive power and the transmission line flows and reactive in their footprint. FE lacked effective high-level visualization tools in its control room and relied upon monitors located on the operators' desks. The operators in turn relied heavily on the alarm screens and the alarm processor to determine what was happening on their system.

The lack of diagrams or maps of the FE system at MISO left MISO to ascertain actual system conditions from static maps and tabular displays requiring significant effort to determine the status of the system. This was the primary reason MISO was unable to assess FE’s system conditions.

MISO relied heavily on the use of a flowgate monitoring tool to determine the health of the system. Flowgates are transmission paths comprised of groups of transmission lines within the bulk electric system. Flowgates are sometimes constrained by unscheduled parallel flow. However, not all constrained transmission paths are necessarily flowgates. By focusing solely on flowgates, MISO failed to monitor all of the critical transmission facilities within its reliability coordinator footprint.

On August 14, there were several problems with visibility:

- FE had a major problem with the lack of alarms, but there were also short but critical periods where displays were taking up to a minute to respond to input from the operator.

This led to the posting of untimely information and a mistrust of the source by system operators.

- At various times on August 14, different parties were trying to verify conditions on the system but had different values for the same parameter (e.g., PJM-MISO-AEP-FE). This was due to different types and timing of data updates used by these entities. In some cases, it took up to 30 seconds between raw data updates and, if operators were looking at state-estimated data, delays of up to several minutes resulted in obsolete data because system conditions were changing rapidly. This led to a mistrust of the data and prevented immediate remedial response by system operators.

The inability to see the status of specific lines outside of an operator's system can cause the state estimator and contingency analysis tools to fail to solve acceptably. (i.e., MISO with loss of DPL's Stuart Atlanta line.) Although MISO was receiving system information from FE, MISO had virtually no system displays that showed this data and no electronic linkage between the data for breaker status and what line or equipment it switched on or off (i.e., while MISO had the data, its ability to visualize it on the system was lacking). If the availability of data from outside a system operator's system is limited, the accuracy of analysis tools is substantially diminished near the edges of the system (FE noted that this was true of its system).

Training

Inadequate training of operators in emergency recognition and response has been at the center of almost every blackout since 1965; it was also a significant issue on August 14. The investigation revealed that neither MISO nor FE operators had much formal training, particularly training to recognize and take proper action in emergencies. Both entities depend heavily on on-the-job training without the benefit of simulator experience or classroom instruction.

MISO is a relatively new entity without extensive operating experience, yet the reliability coordinators received little training other than that they could gain on the job. MISO hired system operators with experience in portions of its footprint, and expected them to share their knowledge and experience with the other system operators. MISO made no effort to ensure that this transfer of knowledge and experience took place and offered no formal training. Further, the PJM operator did not appear to be sufficiently trained on the operation of the tool it had to monitor the AEP system, or the physical characteristics of the AEP and surrounding transmission systems.

Operator Communications

Reviews of telephone transcripts from the various control centers on August 14 show that communications between system operators and reliability coordinators failed to provide those operators with an understanding of the developing emergency. With the exception of the AEP-East operator, the conversations were all between individuals and there was little sense of urgency or recognition that anything of significance was occurring on the system beyond some routine line outages. At no time did the affected system operators and reliability coordinators initiate a broader communications effort utilizing predefined communication paths, including the NERC Reliability Coordinator Hotline, which was available for just such an event.

There were no formal channels of communication or official procedures within the FE control room that were commonly followed to share information among personnel. Most information was shared informally through one-on-one conversations. As noted earlier, the shift supervisor, the eastern region dispatcher and the western region dispatcher all worked at consoles that are within 20 feet of each other. However, the control area operator sits with the scheduling operator in a room across the hall from the control room. Decisions about the type of information to share and the timing of communication appear to be at the discretion of the individual on duty. As a result, vital information may not be shared for a variety of reasons including individual personalities and group dynamics, as well as operator workload and experience. All of these factors played a role, at least to some degree, in the lack of communication that occurred within FE on August 14.

Formal communication procedures also were lacking within and between the PJM and MISO reliability coordination centers. While NERC requires reliability coordinators to share certain information regarding the status of the system, these communications did not occur on August 14.

The telephone transcripts from August 14 showed that the operators on the phone rarely identified themselves, their job position, or their company. Also, there seemed to be some confusion from time to time due to the lack of common terms and meanings among the operators. In one instance the MISO operator was expecting a follow-up phone call from the FE operator regarding the status of part of its system, but then took a call from one of the operations support staff who had only been in the control room briefly and did not have any real information about the system. This clearly added to the confusion that day.

Operators must be inquisitive. If one operator has information of a critical nature that is in the responsibility area of another, the operator should press to ensure the recipient of the information understands its implications. With the exception of the AEP operator, the FE, MISO and PJM operators, did not press to make sure the other operator understood the significance of the information they were receiving or seeking to convey.

Emergency Procedures

Most companies, with rare exception, have developed emergency procedures without input from their neighbors, regional reliability council, or reliability coordinator. This leads to confusion when an emergency occurs because system operators from different operating entities do not know what to expect from each other. There have been instances that a company shed load while its neighbor had available generation because the entities failed to coordinate their actions.

Many companies depend on the individual system operator’s knowledge and experience to recognize and guide them in an emergency. This inherently leads to inconsistent operating practices because every system operator has had different experiences, and therefore, will often do different things under the same conditions. In some cases, the system operator may not know the best action to take in a particular circumstance and precious time is consumed trying to figure out what to do (e.g., the six-minute telephone call where the AEP operator was requesting a 3B TLR from the PJM operator but should have been asking for a TLR level 5B or 6 emergency).

Large-scale system emergencies are rare but their consequences are huge. Because of the dire consequences, coordinated training and drills are necessary to ensure that operators are prepared to recognize and effectively respond to emergency situations.

Advanced Power System Analysis Tools

The RTCA provides the ability to analyze the power system under a variety of conditions and configurations to assess the reliability of the system with regard to thermal overloads and voltage issues. A typical use would be to take the existing system model established by the state estimator then simulate all significant contingencies (line, generation, equipment, load outages, etc.) to evaluate whether the system is reliable for that contingency. The results of the study should be made available to the system operator, along with some method of alarming or alerting the operator to unacceptable results. When run regularly on an automatic basis, the RTCA should notify the system operator when the system is operating outside of its reliability requirements. Both the state estimator and the RTCA can also be initiated manually to quickly assess the impacts of observed changes in the system, or before taking an action such as taking a line out of service to assess the impacts.

Developing and maintaining the models and system data for the state estimator and RTCA tools is labor intensive. The biggest issue is keeping the model accurate. Many system transmission operators don't use tools since their effectiveness depends upon the quality of the data received.

Both FE and MISO had tools such as state estimators and RTCA that were designed to assist control room operators during emergencies. However, the overall security of the power grid was being managed by MISO through the use of spreadsheet-based flowgates. While this approach may be adequate for normal market operations, it is inadequate for effective real-time intervention during a rapidly developing emergency or a cascading outage. Further, the LODFs used in the flowgate tools were not dynamically updated to keep these spreadsheet-based approaches current with actual system conditions. During a rapidly developing event, with losses of lines, LODFs can change substantially. Manually updating these values is insufficient.

MISO's state estimator and RTCA were unavailable for virtually the entire period on August 14 up to the point where the system degraded and then cascaded to a blackout. This was largely because the MISO tools were still in the development stage and system outages weren't automatically reflected in MISO's state estimator model. Had this tool been available, it should have alerted system operators to the contingency conditions on FE's system after the Harding-Chamberlin line trip at 1505(this was confirmed by off-line analysis following the disturbance).

FE had a functional RTCA tool, but on August 14 it was not running in automatic mode because of ongoing software problems. No one ascertained that they should manually initiate the RTCA to check reliability as the system was degrading. PJM had RTCA tools but it did not have sufficient model detail to identify FE system problems. AEP had RTCA tools that did identify problems on the FE system after the loss of the Hanna-Juniper line, but it was unable to verify those problems with FE, MISO, or PJM through subsequent communications with those system operators.

At both MISO and FE, the state estimator and RTCA were seen by operators as tools to be used mainly for planning, including performing day-ahead or week-ahead studies. They were not effective for solving real-time problems because design problems made them too difficult to use in time-critical situations.

Given the inherent limitations of human operators to solve complex problems under stress or when provided limited information about the overall status of the system, real-time decision support is greatly needed. This technology is available yet is underutilized by system operators due to common usability issues. These tools need to be redesigned and empirically tested to ensure that their potential benefits will be fully realized.

Maintenance and Backup for Operational Tools

Operational tools require a significant amount of maintenance and support to ensure a high level of availability. In many cases, however, IT personnel do not view control-room computer software and hardware any differently from any other computer applications within the company, regardless of its criticality.

At FE, IT support staff rebooted the servers with the failed alarming module without checking with the control room staff to confirm that all applications were running properly. At MISO, when the state estimator mismatch problem was solved, IT staff left the software in a manual operation mode.

FE did not have an effective backup plan for the loss of EMS functionality, which resulted in the loss of situational awareness of their power system. Backup planning was insufficient as a single point of failure took down the redundancy that was available. While the state estimator and contingency analysis tools were available to FE operators, the automatic mode of operation was disabled. FE system operators had used the manual mode after a contingency or when they are concerned about system conditions, but they did not do so on August 14. Due to the failure of the alarm processor, the FE operators were unaware that a contingency had occurred and, when neighboring system operators attempted to inform them, they did not properly follow up on the information. Because they were unaware of what was happening on the system, they had no reason to manually initiate the contingency analysis program. Had they done so, it might have drawn their attention to the degrading condition of their system.

Cultural Needs in an Evolving Electricity Structure and Environment

As the electric industry has unbundled, companies have not always implemented corresponding changes to corporate culture and responsibility for reliability. For example, some operators used to perform many functions within a company (i.e., the control area operator operated transmission, dispatched generation, purchased and sold energy outside of its system, etc.). As a result, these operators had much more information about the system they were operating, including historical dispatch patterns and strategies for maintaining reliability under a variety of conditions, than many system operators have today. There are now many more unknowns that system operators must deal with and respond to. As a result, while individual system operators may have a smaller scope of functions to perform, the information they receive to perform their jobs is limited as well. This gives them a narrower view of potential problems on the system and produces a greater opportunity for problems to develop because the operation of the interconnected system is in many more hands than it used to be. For some of those entities, system reliability is not a primary driver or is not part of the ingrained corporate culture; some may not even fully understand it.

Although the tasks of system operators have changed, preparing the system operators and their companies for new or changing responsibilities may not have received enough attention. For example, a dependence on tools led to assumptions (e.g., “My alarms tell me when there is a problem.”) that precluded processing the evidence around them. This led to a failure to respond to an emergency because it was not recognized for what it was. If reliability is going to be maintained in the future, regulators and the industry need to review the functional separation of real-time generation monitoring and transmission reliability in light of the reliability concerns arising from the August 14 blackout.

Actions Operators Could Have Taken on August 14

From an operations point of view, there were four actions available to the FE or MISO system operator that might have prevented, or at least delayed, the cascade and subsequent blackout. These actions are premised on the assumption that the system operators had sufficient knowledge of and training on their systems and also had sufficient information about the status of the system upon which to act:

Action Number 1 — Understanding the System Conditions

Although it was clear that the FE system operators were concerned about voltage and were spending significant time and effort on August 14 to gain additional voltage support from their generating plants, they allowed some reactive power-producing facilities to be taken out of service for routine work. Later in the day, necessary and proper safety procedures delayed restoring some out-of-service capacitors.

Had the previous day's studies indicated an impending voltage problem, system operators had several options available to them to correct the situation:

- Additional off-line generation was available.
- If this generation had been brought online to support voltage, the loading on the transmission system would have been different and it is unlikely the cascade would have occurred. Additional generation available within 30 minutes would have been used to reduce contingency overloads and actual emergency overloads.
- FE could have ensured that some capacitors were not taken out of service on the day in question (Wakeman capacitors) and restored others (Avon capacitors) more quickly than it did.

Action Number 2 — Reclosing Transmission Lines

Reclosing transmission lines that have tripped off-line is an action system operators can take to restore the power system to a more secure state. If an operator determines, however, that attempting to reclose a line would result in another fault, trip, and lockout, then the operator would normally take such an action because reclosing into a fault can often put the power system in greater jeopardy than if the transmission line remains out of service.

In the case of the three 345 kV lines that tripped on August 14, each tripped out due to trees in the rights-of-way. The system operators did not know about the tree situation so it is possible they would have attempted to reclose them, but they did not.

If either Chamberlin-Harding or Hanna-Juniper could have been restored to service prior to 1542, Star-South Canton might not have tripped. This is because Star-South Canton would have experienced less flow (76% of its rating) and sagged less than it did when it contacted the tree and tripped out (it was at 96% of its rating at that time). The line actually tripped at 1427 due to a tree contact while carrying less than 55% of its rating.

After 1542, if Hanna-Juniper could have been restored to service, it would have prevented the loss of Sammis-Star and possibly prevented the cascade. Reclosing the Hanna-Juniper line was restricted due to safety for nearby tree clearance work. After the loss of the 138 kV lines due to overload through 1546, subsequent reclosing both of these lines would have been helpful, but not enough to prevent the cascade.

There was a small window of opportunity from 1505 to 1532 wherein system operators could have attempted to reclose the Harding-Chamberlin line, which might have prevented the loss of the Hanna-Juniper line. The recognition of the Harding-Chamberlin outage at 1505 by FE or MISO, and a subsequent reclosing attempt by FE, might have prevented the cascade.

The FE operators indicated that had they known some of these lines were open, they would have attempted to restore them, particularly the Chamberlin-Harding line.

Action Number 3 — Redispatch of Generation in the Cleveland Area

Redispatch is another action that system operators could have taken. Although FE indicated that its generators were meeting schedules, additional capacity and Mvars were available in the south Lake Erie shore area that could have been dispatched to reduce the loadings on the remaining transmission into northern Ohio.

At 1541:35, when the Star-South Canton line tripped and locked out, the Lakeshore, Perry, and Ashtabula units had reactive capability that could have been applied to support voltage and reduce transmission var flow. The Perry unit produced maximum reactive at 1551, but Lakeshore and Ashtabula had more reactive capability when the cascade started at 1606.

Redispatch alone would not have been effective in preventing the cascade unless it included the restoration of the Eastlake 5 unit, or if other off-line local reserve had been scheduled for service prior to or after the Eastlake 5 unit trip. However, redispatch of the remaining local MW and Mvar generation reserves from 1505 to 1606 might have bought sufficient time to shed load through the manual emergency load shedding procedure.

Action Number 4 – Direct Load Shedding

Load shedding would have prevented the power system emergency from cascading to the extent that it did. The system modeling team has completed analysis showing that had 500 MW of load been shed in the Cleveland area early in the event, the cascade would not have occurred. Later in the event, more load would have needed to be shed to prevent the cascade. However, the FE operators did not have the capability to quickly shed load anywhere on its system, and did not have the capability to shed load in the Cleveland area.

Recommendations

A number of deficiencies have been identified through this analysis of the performance of system operators and their supporting tools and systems. These deficiencies must be addressed to assure the industry is prepared and will take the necessary actions to prevent future large-scale system disturbances and blackouts. These recommendations can be grouped into the following areas of system monitoring, training, communications and coordination, and system operator roles and responsibilities.

System Monitoring

The complexity of the interconnected bulk electric system, and the speed with which things can happen, demand that operators have the best tools available to monitor the system with the necessary processes to produce visualizations and information whereby the system operators recognize impending emergencies and know what actions to take.

Operations Recommendation 1 — System Monitoring Tools

NERC must establish clear standards defining minimum requirements for the system monitoring and evaluation tools, capabilities, and procedures necessary for system operators who are or could become responsible for monitoring and preserving the reliability of the bulk electric system. System operators must have the information required to monitor the health of the system and to identify and take actions to prevent degradation of the system beyond established limits. These standards must address the tools, capabilities, and procedures necessary in all operational control centers, including reliability coordinators, control areas, and future functional model entities. These standards must address the following key areas:

- **Functionality —** The standards must establish minimum levels of functionality. The minimum functionality must include the ability to:
    - Monitor the status and operating parameters of the operating area in real time.
    - Automatically alert the system operators to status changes and violated operating parameters.
    - Determine the state or health of the system at all times for the operating area of the entity in the context of the larger interconnected system.
    - Evaluate all contingencies that may have a reliability impact on the operating area whether in the operating area or not.
    - Automatically identify and alert the system operators of potential reliability risks.
    - Provide the operator with the ability to identify and review solutions to reliability risks.

- **Area Monitored —** Reliability coordinators and control areas must monitor an area greater than their operational area to identify all reliability risks to their operational area. The area monitored should be based on ability of state estimation and contingency analysis to produce accurate solutions when facilities outside of the operational area are removed from service. Reliability coordinators must have state estimators to validate the data being received and contingency analysis tools that operate automatically and alert the system operators to violated parameters. Control areas, reliability coordinators, and functional model entities must monitor all 100 kV and higher equipment within their respective footprints unless the facility can be shown to have no impact on the bulk electric system.

- **Data —** The standards must ensure sufficient data (equipment status and system parameters) is exchanged with sufficient speed and periodicity to assure those responsible for reliability have the ability to identify, evaluate, and respond to quickly evolving power system condition changes. Operating entities, including reliability coordinators, control areas, and functional model entities must utilize common data in order to have the same information at the same time. When discussing or validating power system data, entities shall be clear on what their data source is and make sure they are fully aware of the real time actual measured data. State estimated data must only be used to ensure the validity of the real-time data.

- **Human Factors and Visualization —** The standards must ensure human factors are incorporated into the design of control room environments and displays need to optimize the presentation of information to system operators. The displays and alarms must focus the operator's attention on the highest priority need and action. The standards must recognize the system operator's need for a system overview (e.g., map boards) so the operator can get a sense of the status of the system quickly and at a glance.

- **Criticality and Redundancy** — The standards must recognize and require that all system monitoring hardware, software, and related systems and tools (power supply, communications, data handling, and processing, etc.) used in system control centers that monitor, control or otherwise manage power systems or major power system elements, must be deemed as critical energy infrastructure.

  The standards must include requirements defining awareness, management, and preparedness for loss of any part of or total loss of the primary operational control center for extended periods of time. The standards must also identify when a fully redundant backup control center is required and establish criteria addressing:
    - Backup control center requirements.
    - Proximity to primary control center.
    - Operations during transfer of control and need for hot standby.
    - Single points of failure.
    - Reliance on the primary center for data or processing.
    - Criteria for the transfer of control.

  The standards must address failure modes and actions for system monitoring hardware, and require that plans be implemented so that operating personnel can effectively monitor and manage their operational area when a system is in a failure or poor performance condition. The standards must require sufficient testing of monitoring systems to identify degraded performance or failure of components and must notify system operators and reliability coordinators of the status of their tools at all times.

Operations Recommendation 2 — System Monitoring Procedures

NERC standards currently include requirements for control areas to have emergency and system restoration and black start plans. NERC must establish standards with clear requirements defining specific subject areas. Reliability coordinators, control areas, and functional model entities must develop and maintain operating procedures to identify roles, responsibilities, and actions expected of system operators for potential and developing emergency conditions.

NERC must establish standards requiring operating entities to define emergency operating conditions on their systems, including loss of the primary control center, and what actions the operators should take when these emergency operating conditions are likely or eminent.

Operations Recommendation 3 — System Monitoring Organization Certification

Reliability coordinators were initially approved based on a review of a regional reliability plan. These plans provide a description of how reliability responsibilities will be assigned and addressed within the region. The individual reliability coordinator did not provide a plan describing how it would meet its requirements.

NERC must establish clear criteria identifying the requirements of both regional reliability plans and reliability coordinator implementation plans. These plans must be initially reviewed and approved with periodic updates and approval by NERC.

NERC must also establish a process to verify all entities with bulk electric system responsibilities fully meet the approved implementation plans and criteria established prior to assuming responsibilities or authorities and becoming operational. Changes in operational scope or footprints must not occur until the incoming organization can achieve the level of performance and knowledge as defined and required by NERC. All tools and capabilities must be demonstrated to be fully operational. These tools and capabilities must include all data and alarming capabilities sufficient to fully exercise their responsibilities under time-limited circumstances and develop comprehensive monitoring capabilities and displays for the system operator to accurately determine the condition of the interconnected transmission system under the operator’s control.

The certification or recertification process must assess the amount of staff needed for reliability entities to adequately support all tools, processes, procedures, training, and actual operations including support for state estimators and contingency analysis tools.

Training

System operators at control areas, reliability coordinators, and other operating entities must have continuous and repeated training in the art of recognizing and responding to threats to the reliability of the interconnected bulk electric system. The system operators must be trained on the use of a comprehensive and complicated set of system monitoring tools, actions to be taken, and communications protocols and procedures.

Operations Recommendation 4 — Training

NERC must establish clear standards defining minimum requirements for continuous and repeated training of system operators and associated support personnel. These training standards must define the training required for new as well as experienced system operators in the following areas:

- Recognition and Response to System Emergencies
    - Emergency drills and responses.
    - Load shedding – automatic (underfrequency and undervoltage) and manual.
    - Operating from backup control centers.
    - System operations during unstudied situations.
    - System protection.
    - Geomagnetic disturbances weather impacts on system operations.
    - System monitoring – voltage, equipment loading.
    - RTCA.
    - Off-line system analysis tools.
    - Monitoring backup plans.
    - Sabotage, physical, and cyber threats and responses.
- Standards and Operating Procedures
    - NERC reliability standards.
    - Regional, subregional, and ISO/RTO reliability standards and operating procedures.
- Power System Restoration Processes, Procedures, and Philosophy
    - Blackstart.
    - Interconnection of islands – building islands.
    - Load restoration philosophies.
- Interconnected Power System Operations
    - Operations coordination.
    - Special protections systems.
    - Special operating guides.
    - Voltage and reactive control, including responding to eminent voltage collapse.
    - Understanding the concepts of interconnection reliability operating limits versus system operating limits.
    - DC tie operations and procedures during system emergencies.
    - Thermal and dynamic limits.
    - Unscheduled flow mitigation−congestion management.
    - Local and regional line loading procedures.
    - Radial load and generation operations and procedures.

  - Tie line operations.
  - Interchange scheduling.
  - Generating unit operating characteristics and limits.
- Technologies and Tools
  - Forecasting tools.
  - Power system study tools and dispatcher power flow.
  - Maintenance of system monitoring tools (for support personnel).
  - Real-time, hour-ahead, and day-ahead tools.
- Communications and Coordination
  - Communication tools, protocols, procedures, responsibilities, and coordination.
  - Overlapping responsibilities within and outside of the area of operations.
  - The need for system operators to be inquisitive about conditions that seem unusual or abnormal both within their area and neighboring areas.
  - Recognize and communicate when in an emergency condition.
  - Strategically assessing and prioritizing control center activity when in an emergency (e.g., delegate routine phone calls, next-hour scheduling reconciliation).
  - Control room operating procedures.

The standards must address where on-the-job training is appropriate. The only area where it is appropriate is for learning how to operate a specific piece of equipment. For instance, how to work the computer to get the desired display, or how to work the telephone system. Other areas are more theoretical and must be taught using classrooms, role playing, and simulations. The training required through these standards must apply to both system operator and organization certification.

Communications and Coordination

Communication protocols and coordination agreements with all adjacent control areas, reliability coordinators, and other operating entities must be in place to ensure reliable and efficient operation of the bulk electric system. Operators must communicate efficiently and effectively at all times, particularly during developing system emergencies.

Operations Recommendation 5 — Communication Protocols and Coordination Agreements.

NERC must develop industry-wide structured communications protocols and procedures for use by system operators. These protocols should address the following subjects:

- When to communicate.
- Communication procedures and protocols within and between control centers.
- Identification of communication responsibilities for all parties including reliability coordinators, control areas, generators, transmission operators, etc.
- Identification of the individual, who they represent, and the area(s) of responsibility and authority.
- Maximizing content while minimizing communication time.
- Clarity of communications.
- Basis of information or observations.
- Communication and confirmation of directives and instructions.

NERC must also establish organization certification requirements defining when coordination agreements are required as well as the requirements for the areas these coordination agreements must address including: organization responsibility and authority, lead roles, and communications protocols.

Roles and Responsibilities

Functional unbundling, corporate restructuring, and the establishment of new entities such as ISOs and RTOs have increasingly clouded the roles and responsibilities of system operators. These roles and responsibilities must be clearly defined at all levels to prevent confusion and preserve the reliability of the interconnected bulk electric system.

Operations Recommendation 6 — Reliability Roles and Responsibilities

NERC and the industry must establish clear definitions of the role and authority of reliability coordinators, control areas, and other entities defined in the Reliability Functional Model. These definitions must be consistent across North America. Differences in duties and responsibilities of different reliability coordinators create an unacceptable level of confusion and increase reliability risk. NERC and the industry must define and implement the functional model as soon as possible. NERC and the industry must consider the following when reviewing and establishing clear definitions for roles and responsibilities under the model:

- The separation of real-time generation monitoring and transmission reliability monitoring and associated inability to effectively communicate and monitor as a result of functional unbundling.
- The need for “defense-in-depth” or a second set of eyes to effectively see the actions/conditions and direct corrective actions between reliability coordinators, control areas, and functional model entities.
- The need to establish a clear separation between the reliability coordinator and the control area operators (and any functional model-defined system operators) to eliminate the unacceptable level of confusion and reliability risk that occurs when these responsibilities are combined within a single entity.

Operations Recommendation 7 — Operational Plans and Tools

NERC must establish clear standards requiring control areas, reliability coordinators, and other entities with reliability responsibilities to have plans and tools available to the system operators. The requirements must identify the minimum plans and tools required for each of these entities including:

- Load shedding (automatic under voltage and manual) under the direct control of the system operator that is constantly available, can be implemented within five minutes, distributed across the system to relieve transmission system deficiencies, and periodically tested to ensure coordination between the parties and that system operators remain familiar with its implementation.
- Availability and control of all reactive sources at all times.
- Providing the system operators with defined actions to take for a variety of system events based on current-day operational conditions.