5. How and Why the Blackout Began in Ohio

Summary

This chapter explains the major events—electrical, computer, and human—that occurred as the blackout evolved on August 14, 2003, and identifies the causes of the initiation of the blackout. The period covered in this chapter begins at 12:15 Eastern Daylight Time (EDT) on August 14, 2003 when inaccurate input data rendered MISO's state estimator (a system monitoring tool) ineffective. At 13:31 EDT, FE's Eastlake 5 generation unit tripped and shut down automatically. Shortly after 14:14 EDT, the alarm and logging system in FE's control room failed and was not restored until after the blackout. After 15:05 EDT, some of FE's 345-kV transmission lines began tripping out because the lines were contacting overgrown trees within the lines' right-of-way areas.

By around 15:46 EDT when FE, MISO and neighboring utilities had begun to realize that the FE system was in jeopardy, the only way that the blackout might have been averted would have been to drop at least 1,500 MW of load around Cleveland and Akron. No such effort was made, however, and by 15:46 EDT it may already have been too late for a large load-shed to make any difference. After 15:46 EDT, the loss of some of FE's key 345-kV lines in northern Ohio caused its underlying network of 138-kV lines to begin to fail, leading in turn to the loss of FE's Sammis-Star 345-kV line at 16:06 EDT. The chapter concludes with the loss of FE's Sammis-Star line, the event that triggered the uncontrollable 345 kV cascade portion of the blackout sequence.

The loss of the Sammis-Star line triggered the cascade because it shut down the 345-kV path into northern Ohio from eastern Ohio. Although the area around Akron, Ohio was already blacked out due to earlier events, most of northern Ohio remained interconnected and electricity demand was high. This meant that the loss of the heavily overloaded Sammis-Star line instantly created major and unsustainable burdens on lines in adjacent areas, and the cascade spread rapidly as lines and generating units automatically tripped by protective relay action to avoid physical damage.

Chapter Organization

This chapter is divided into several phases that correlate to major changes within the FirstEnergy system and the surrounding area in the hours leading up to the cascade:

- **Phase 1:** A normal afternoon degrades
- **Phase 2:** FE's computer failures
- **Phase 3:** Three FE 345-kV transmission line failures and many phone calls
- **Phase 4:** The collapse of the FE 138-kV system and the loss of the Sammis-Star line.

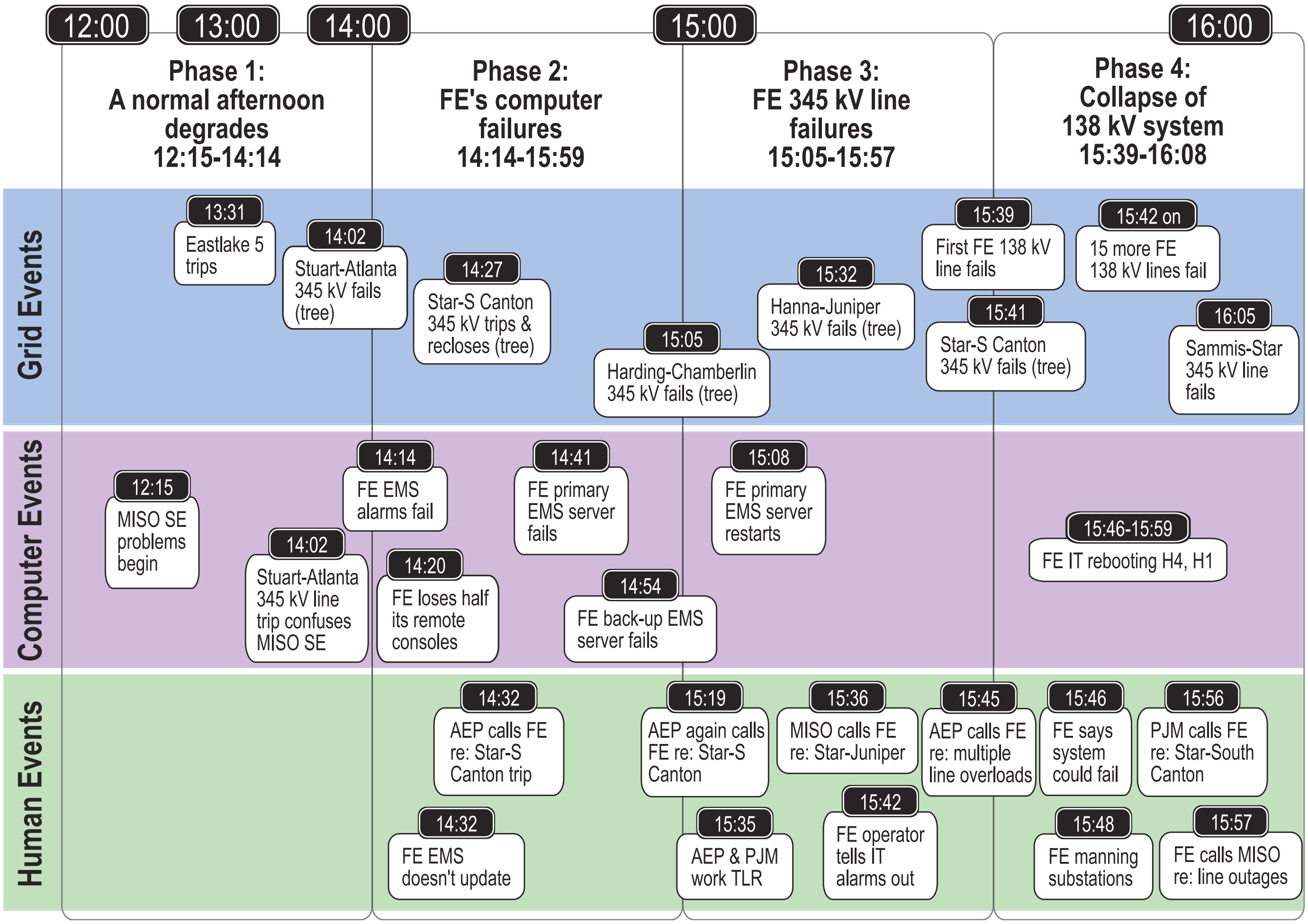
Key events within each phase are summarized in Figure 5.1, a timeline of major events in the origin of the blackout in Ohio. The discussion that follows highlights and explains these significant events within each phase and explains how the events were related to one another and to the cascade. Specific causes of the blackout and associated recommendations are identified by icons.

Phase 1: A Normal Afternoon Degrades: 12:15 EDT to 14:14 EDT

Overview of This Phase

Northern Ohio was experiencing an ordinary August afternoon, with loads moderately high to serve air conditioning demand, consuming high levels of reactive power. With two of Cleveland's active and reactive power production anchors already shut down (Davis-Besse and Eastlake 4), the loss of the Eastlake 5 unit at 13:31 EDT further depleted critical voltage support for the Cleveland-Akron area. Detailed simulation modeling reveals that the loss of Eastlake 5 was a significant factor in the outage later that afternoon—with Eastlake 5 out of service, transmission line

Figure 5.1. Timeline: Start of the Blackout in Ohio



loadings were notably higher but well within normal ratings. After the loss of FE's Harding-Chamberlin line at 15:05 EDT, the system eventually became unable to sustain additional contingencies, even though key 345 kV line loadings did not exceed their normal ratings. Had Eastlake 5 remained in service, subsequent line loadings would have been lower. Loss of Eastlake 5, however, did not initiate the blackout. Rather, subsequent computer failures leading to the loss of situational awareness in FE's control room and the loss of key FE transmission lines due to contacts with trees were the most important causes.

At 14:02 EDT, Dayton Power & Light's (DPL) Stuart-Atlanta 345-kV line tripped off-line due to a tree contact. This line had no direct electrical effect on FE's system—but it did affect MISO's performance as reliability coordinator, even though PJM is the reliability coordinator for the DPL line. One of MISO's primary system condition evaluation tools, its state estimator, was unable to assess system conditions for most of the period between 12:15 and 15:34 EDT, due to a combination of human error and the effect of the loss of DPL's Stuart-Atlanta line on other MISO lines as reflected in the state estimator's calculations. Without an effective state estimator, MISO was unable to perform contingency analyses of generation and line losses within its reliability zone. Therefore, through 15:34 EDT MISO could not determine that with Eastlake 5 down, other transmission lines would overload if FE lost a major transmission line, and could not issue appropriate warnings and operational instructions.

In the investigation interviews, all utilities, control area operators, and reliability coordinators indicated that the morning of August 14 was a reasonably typical day.[1] FE managers referred to it as peak load conditions on a less than peak load day. Dispatchers consistently said that while voltages were low, they were consistent with historical voltages.[2] Throughout the morning and early afternoon of August 14, FE reported a growing need for voltage support in the upper Midwest.

The FE reliability operator was concerned about low voltage conditions on the FE system as early as 13:13 EDT. He asked for voltage support (i.e., increased reactive power output) from FE's interconnected generators. Plants were operating in automatic voltage control mode (reacting to system voltage conditions and needs rather than constant reactive power output). As directed in FE's Manual of Operations,[3] the FE reliability operator began to call plant operators to ask for additional voltage support from their units. He noted to most of them that system voltages were sagging "all over." Several mentioned that they were already at or near their reactive output limits. None were asked to reduce their real power output to be able to produce more reactive output. He called the Sammis plant at 13:13 EDT, West Lorain at 13:15 EDT, Eastlake at 13:16 EDT, made three calls to unidentified plants between 13:20 EDT and 13:23 EDT, a "Unit 9" at 13:24 EDT, and two more at 13:26 EDT and 13:28 EDT.[4] The operators worked to get shunt capacitors at Avon that were out of service restored to support voltage,[5] but those capacitors could not be restored to service.

Following the loss of Eastlake 5 at 13:31 EDT, FE's operators' concern about voltage levels increased. They called Bay Shore at 13:41 EDT and Perry at

Energy Management System (EMS) and Decision Support Tools

Operators look at potential problems that could arise on their systems by using contingency analyses, driven from state estimation, that are fed by data collected by the SCADA system.

SCADA: System operators use **S**ystem **C**ontrol **a**nd **D**ata **A**cquisition systems to acquire power system data and control power system equipment. SCADA systems have three types of elements: field remote terminal units (RTUs), communication to and between the RTUs, and one or more Master Stations.

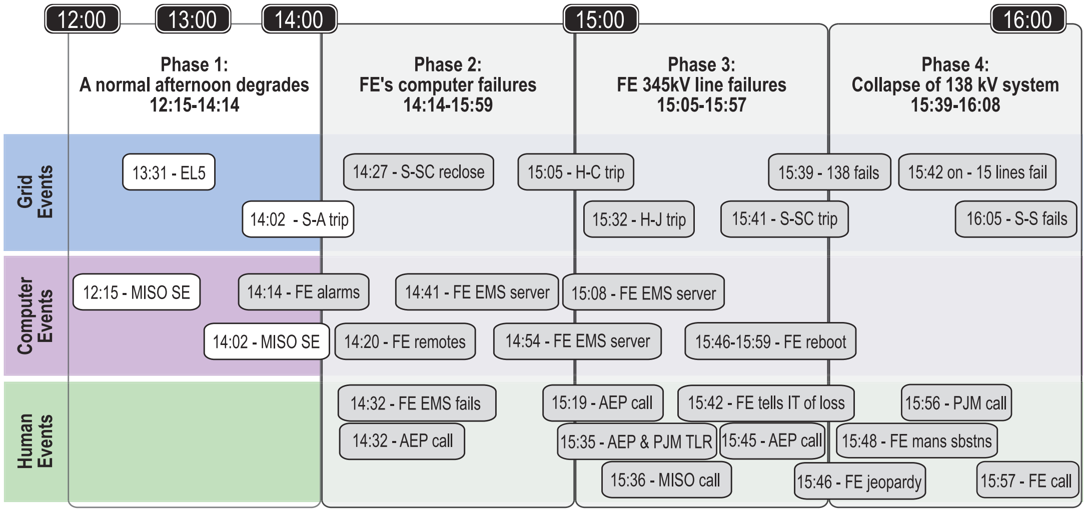
Field RTUs, installed at generation plants and substations, are combination data gathering and device control units. They gather and provide information of interest to system operators, such as the status of a breaker (switch), the voltage on a line or the amount of real and reactive power being produced by a generator, and execute control operations such as opening or closing a breaker. Telecommunications facilities, such as telephone lines or microwave radio channels, are provided for the field RTUs so they can communicate with one or more SCADA Master Stations or, less commonly, with each other.

Master stations are the pieces of the SCADA system that initiate a cycle of data gathering from the field RTUs over the communications facilities, with time cycles ranging from every few seconds to as long as several minutes. In many power systems, Master Stations are fully integrated into the control room, serving as the direct interface to the Energy Management System (EMS), receiving incoming data from the field RTUs and relaying control operations commands to the field devices for execution.

State Estimation: Transmission system operators must have visibility (condition information) over their own transmission facilities, and recognize the impact on their own systems of events and facilities in neighboring systems. To accomplish this, system state estimators use the real-time data measurements available on a subset of those facilities in a complex mathematical model of the power system that reflects the configuration of the network (which facilities are in service and which are not) and real-time system condition data to estimate voltage at each bus, and to estimate real and reactive power flow quantities on each line or through each transformer. Reliability coordinators and control areas that have them commonly run a state estimator on regular intervals or only as the need arises (i.e., upon demand). Not all control areas use state estimators.

Contingency Analysis: Given the state estimator's representation of current system conditions, a system operator or planner uses contingency analysis to analyze the impact of specific outages (lines, generators, or other equipment) or higher load, flow, or generation levels on the security of the system. The contingency analysis should identify problems such as line overloads or voltage violations that will occur if a new event (contingency) happens on the system. Some transmission operators and control areas have and use state estimators to produce base cases from which to analyze next contingencies ("N-1," meaning normal system minus 1 key element) from the current conditions. This tool is typically used to assess the reliability of system operation. Many control areas do not use real time contingency analysis tools, but others run them on demand following potentially significant system events.

Figure 5.2. Timeline Phase 1



13:43 EDT to ask the plants for more voltage support. Again, while there was substantial effort to support voltages in the Ohio area, FirstEnergy personnel characterized the conditions as not being unusual for a peak load day, although this was not an all-time (or record) peak load day.[6]

Key Phase 1 Events

1A) 12:15 EDT to 16:04 EDT: MISO's state estimator software solution was compromised, and MISO's single contingency reliability assessment became unavailable.

1B) 13:31:34 EDT: Eastlake Unit 5 generation tripped in northern Ohio.

1C) 14:02 EDT: Stuart-Atlanta 345-kV transmission line tripped in southern Ohio.

1A) MISO's State Estimator Was Turned Off: 12:15 EDT to 16:04 EDT

It is common for reliability coordinators and control areas to use a state estimator (SE) to improve the accuracy of the raw sampled data they have for the electric system by mathematically processing raw data to make it consistent with the electrical system model. The resulting information on equipment voltages and loadings is used in software tools such as real time contingency analysis (RTCA) to simulate various conditions and outages to evaluate the reliability of the power system. The RTCA tool is used to alert operators if the system is operating insecurely; it can be run either on a regular schedule (e.g., every 5 minutes), when triggered by some system event (e.g., the loss of a power plant or transmission line), or when initiated by an operator. MISO usually runs the SE every 5 minutes, and the RTCA less frequently. If the model does not have accurate and timely information about key pieces of system equipment or if key input data are wrong, the state estimator may be unable to reach a solution or it will reach a solution that is labeled as having a high degree of error. In August, MISO considered its SE and RTCA tools to be still under development and not fully mature; those systems have since been completed and placed into full operation.

On August 14 at about 12:15 EDT, MISO's state estimator produced a solution with a high mismatch (outside the bounds of acceptable error). This was traced to an outage of Cinergy's Bloomington-Denois Creek 230-kV line—although it was out of service, its status was not updated in MISO's state estimator. Line status information within MISO's reliability coordination area is transmitted to MISO by the ECAR data network or direct links and is intended to be automatically linked to the SE. This requires coordinated data naming as well as instructions that link the data to the tools. For this line, the automatic linkage of line status to the state estimator had not yet been established. The line status was corrected and MISO's analyst obtained a good SE solution at 13:00 EDT and an RTCA solution at 13:07 EDT. However, to troubleshoot this problem the analyst had turned off the automatic trigger that runs the state estimator every five minutes. After fixing the problem he forgot to re-enable it, so although he had successfully run the SE and RTCA manually to reach a set of correct system analyses, the tools were not returned to normal automatic operation. Thinking the system had been successfully restored, the analyst went to lunch.

Cause 4
Inadequate RC Diagnostic Support

The fact that the state estimator was not running automatically on its regular 5-minute schedule was discovered about 14:40 EDT. The automatic trigger was re-enabled but again the state estimator failed to solve successfully. This time investigation identified the Stuart-Atlanta 345-kV line outage (which occurred at 14:02 EDT) to be the likely cause. This line is within the Dayton Power and Light control area in southern Ohio and is under PJM's reliability umbrella rather than MISO's. Even though it affects electrical flows within MISO, its status had not been automatically linked to MISO's state estimator.

The discrepancy between actual measured system flows (with Stuart-Atlanta off-line) and the MISO model (which assumed Stuart-Atlanta on-line) prevented the state estimator from solving correctly. At 15:09 EDT, when informed by the system engineer that the Stuart-Atlanta line appeared to be the problem, the MISO operator said (mistakenly) that this line was in service. The system engineer then tried unsuccessfully to reach a solution with the Stuart-Atlanta line modeled as in service until approximately 15:29 EDT, when the MISO operator called PJM to verify the correct status. After they determined that Stuart-Atlanta had tripped, they updated the state estimator and it solved successfully. The RTCA was then run manually and solved successfully at 15:41 EDT. MISO's state estimator and contingency analysis were back under full automatic operation and solving effectively by 16:04 EDT, about two minutes before the start of the cascade.

In summary, the MISO state estimator and real time contingency analysis tools were effectively out of service between 12:15 EDT and 16:04 EDT. This prevented MISO from promptly performing precontingency "early warning" assessments of power system reliability over the afternoon of August 14.

Recommendations
3, page 143; 6, page 147; 30, page 163

1B) Eastlake Unit 5 Tripped: 13:31 EDT

Eastlake Unit 5 (rated at 597 MW) is in northern Ohio along the southern shore of Lake Erie, connected to FE's 345-kV transmission system (Figure 5.3). The Cleveland and Akron loads are generally supported by generation from a combination of the Eastlake, Perry and Davis-Besse units, along with significant imports, particularly from 9,100 MW of generation located along the Ohio and Pennsylvania border. The unavailability of Eastlake 4 and Davis-Besse meant that FE had to import more energy into the Cleveland-Akron area to support its load.

When Eastlake 5 dropped off-line, replacement power transfers and the associated reactive power to support the imports to the local area contributed to the additional line loadings in the region. At 15:00 EDT on August 14, FE's load was approximately 12,080 MW, and they were importing about 2,575 MW, 21% of their total. FE's system reactive power needs rose further.

Cause 1
Inadequate System Understanding

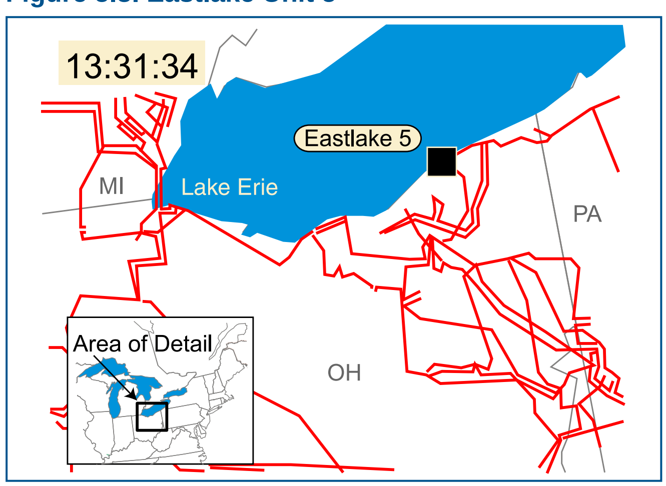
The investigation team's system simulations indicate that the loss of Eastlake 5 was a critical step in the sequence of events. Contingency analysis simulation of the conditions following the loss of the Harding-Chamberlin 345-kV circuit at 15:05 EDT showed that the system would be unable to sustain some contingencies without line overloads above emergency ratings. However, when Eastlake 5 was modeled as in service and fully available in those simulations, all overloads above emergency limits were eliminated, even with the loss of Harding-Chamberlin.

Recommendation
23, page 160

Cause 2
Inadequate Situational Awareness

FE did not perform a contingency analysis after the loss of Eastlake 5 at 13:31 EDT to determine whether the loss of further lines or plants would put their system at risk. FE also did not perform a contingency analysis after the loss of Harding-Chamberlin at 15:05 EDT (in part because they did not know that it had tripped out of service), nor does the utility routinely conduct such studies.[7] Thus FE did not discover that their system was no longer in an N-1

Figure 5.3. Eastlake Unit 5



secure state at 15:05 EDT, and that operator action was needed to remedy the situation.

Recommendations
3, page 143, 22, page 159

1C) Stuart-Atlanta 345-kV Line Tripped: 14:02 EDT

Cause 1
Inadequate System Understanding

The Stuart-Atlanta 345-kV transmission line is in the control area of Dayton Power and Light. At 14:02 EDT the line tripped due to contact with a tree, causing a short circuit to ground, and locked out. Investigation team modeling reveals that the loss of DPL's Stuart-Atlanta line had no significant electrical effect on power flows and voltages in the FE area. The team examined the security of FE's system, testing power flows and voltage levels with the combination of plant and line outages that evolved on the afternoon of August 14. This analysis shows that the availability or unavailability of the Stuart-Atlanta 345-kV line did not change the capability or performance of FE's system or affect any line loadings within the FE system, either immediately after its trip or later that afternoon. The only reason why Stuart-Atlanta matters to the blackout is because it contributed to the failure of MISO's state estimator to operate effectively, so MISO could not fully identify FE's precarious system conditions until 16:04 EDT.[8]

Data Exchanged for Operational Reliability

The topology of the electric system is essentially the road map of the grid. It is determined by how each generating unit and substation is connected to all other facilities in the system and at what voltage levels, the size of the individual transmission wires, the electrical characteristics of each of those connections, and where and when series and shunt reactive devices are in service. All of these elements affect the system's impedance—the physics of how and where power will flow across the system. Topology and impedance are modeled in power-flow programs, state estimators, and contingency analysis software used to evaluate and manage the system.

Topology processors are used as front-end processors for state estimators and operational display and alarm systems. They convert the digital telemetry of breaker and switch status to be used by state estimators, and for displays showing lines being opened or closed or reactive devices in or out of service.

A variety of up-to-date information on the elements of the system must be collected and exchanged for modeled topology to be accurate in real time. If data on the condition of system elements are incorrect, a state estimator will not successfully solve or converge because the real-world line flows and voltages being reported will disagree with the modeled solution.

Data Needed: A variety of operational data is collected and exchanged between control areas and reliability coordinators to monitor system performance, conduct reliability analyses, manage congestion, and perform energy accounting. The data exchanged range from real-time system data, which is exchanged every 2 to 4 seconds, to OASIS reservations and electronic tags that identify individual energy transactions between parties. Much of these data are collected through operators' SCADA systems.

ICCP: Real-time operational data is exchanged and shared as rapidly as it is collected. The data is passed between the control centers using an Inter-Control Center Communications Protocol (ICCP), often over private frame relay networks. NERC operates one such network, known as NERCNet. ICCP data are used for minute-to-minute operations to monitor system conditions and control the system, and include items such as line flows, voltages, generation levels, dynamic interchange schedules, area control error (ACE), and system frequency, as well as in state estimators and contingency analysis tools.

IDC: Since the actual power flows along the path of least resistance in accordance with the laws of physics, the NERC Interchange Distribution Calculator (IDC) is used to determine where it will actually flow. The IDC is a computer software package that calculates the impacts of existing or proposed power transfers on the transmission components of the Eastern Interconnection. The IDC uses a power flow model of the interconnection, representing over 40,000 substation buses, 55,000 lines and transformers, and more than 6,000 generators. This model calculates transfer distribution factors (TDFs), which tell how a power transfer would load up each system

(continued on page 51)

Phase 2:
FE's Computer Failures: 14:14 EDT to 15:59 EDT

Overview of This Phase

Starting around 14:14 EDT, FE's control room operators lost the alarm function that provided audible and visual indications when a significant piece of equipment changed from an acceptable to a problematic condition. Shortly thereafter, the EMS system lost a number of its remote control consoles. Next it lost the primary server computer that was hosting the alarm function, and then the backup server such that all functions that were being supported on these servers were stopped at 14:54 EDT. However, for over an hour no one in FE's control room grasped that their computer systems were not operating properly, even though FE's Information Technology support staff knew of the problems and were working to solve them, and the absence of alarms and other symptoms offered many clues to the operators of the EMS system's impaired state. Thus, without a functioning EMS or the knowledge that it had failed, FE's system operators remained unaware that their electrical system condition was beginning to

Data Exchanged for Operational Reliability (Continued)

element, and outage transfer distribution factors (OTDFs), which tell how much power would be transferred to a system element if another specific system element were lost.

The IDC model is updated through the NERC System Data Exchange (SDX) system to reflect line outages, load levels, and generation outages. Power transfer information is input to the IDC through the NERC electronic tagging (E-Tag) system.

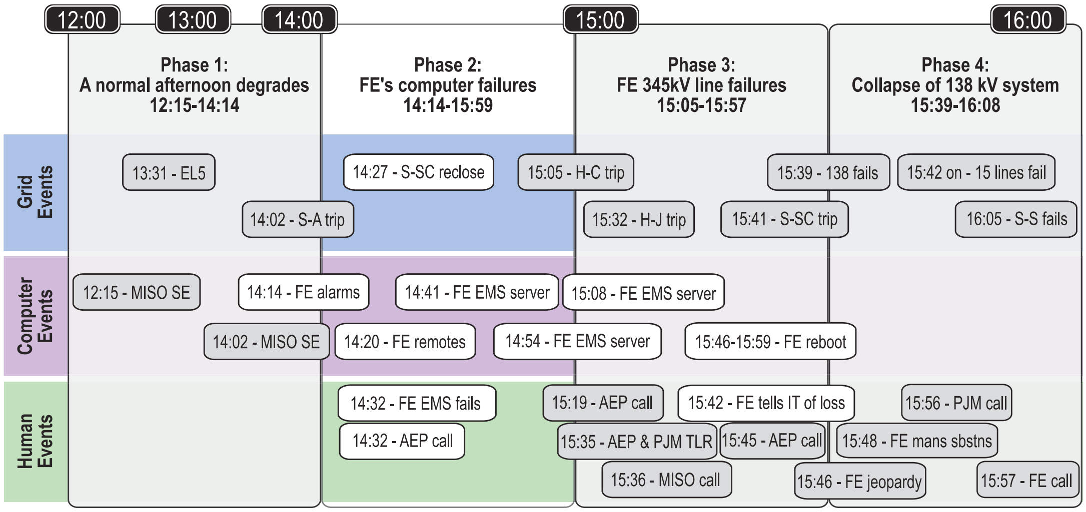
SDX: The IDC depends on element status information, exchanged over the NERC System Data Exchange (SDX) system, to keep the system topology current in its powerflow model of the Eastern Interconnection. The SDX distributes generation and transmission outage information to all operators, as well as demand and operating reserve projections for the next 48 hours. These data are used to update the IDC model, which is used to calculate the impact of power transfers across the system on individual transmission system elements. There is no current requirement for how quickly asset owners must report changes in element status (such as a line outage) to the SDX—some entities update it with facility status only once a day, while others submit new information immediately after an event occurs. NERC is now developing a requirement for regular information update submittals that is scheduled to take effect in the summer of 2004.

SDX data are used by some control centers to keep their topology up-to-date for areas of the interconnection that are not observable through direct telemetry or ICCP data. A number of transmission providers also use these data to update their transmission models for short-term determination of available transmission capability (ATC).

E-Tags: All inter-control area power transfers are electronically tagged (E-Tag) with critical information for use in reliability coordination and congestion management systems, particularly the IDC in the Eastern Interconnection. The Western Interconnection also exchanges tagging information for reliability coordination and use in its unscheduled flow mitigation system. An E-Tag includes information about the size of the transfer, when it starts and stops, where it starts and ends, and the transmission service providers along its entire contract path, the priorities of the transmission service being used, and other pertinent details of the transaction. More than 100,000 E-Tags are exchanged every month, representing about 100,000 GWh of transactions. The information in the E-Tags is used to facilitate curtailments as needed for congestion management.

Voice Communications: Voice communication between control area operators and reliability is an essential part of exchanging operational data. When telemetry or electronic communications fail, some essential data values have to be manually entered into SCADA systems, state estimators, energy scheduling and accounting software, and contingency analysis systems. Direct voice contact between operators enables them to replace key data with readings from the other systems' telemetry, or surmise what an appropriate value for manual replacement should be. Also, when operators see spurious readings or suspicious flows, direct discussions with neighboring control centers can help avert problems like those experienced on August 14, 2003.

Figure 5.4. Timeline Phase 2



degrade. Unknowingly, they used the outdated system condition information they did have to discount information from others about growing system problems.

Key Events in This Phase

2A) 14:14 EDT: FE alarm and logging software failed. Neither FE's control room operators nor FE's IT EMS support personnel were aware of the alarm failure.

2B) 14:20 EDT: Several FE remote EMS consoles failed. FE's Information Technology (IT) engineer was computer auto-paged.

2C) 14:27:16 EDT: Star-South Canton 345-kV transmission line tripped and successfully reclosed.

2D) 14:32 EDT: AEP called FE control room about AEP indication of Star-South Canton 345-kV line trip and reclosure. FE had no alarm or log of this line trip.

2E) 14:41 EDT: The primary FE control system server hosting the alarm function failed. Its applications and functions were passed over to a backup computer. FE's IT engineer was auto-paged.

2F) 14:54 EDT: The FE back-up computer failed and all functions that were running on it stopped. FE's IT engineer was auto-paged.

Failure of FE's Alarm System

Cause 2
Inadequate Situational Awareness

FE's computer SCADA alarm and logging software failed sometime shortly after 14:14 EDT (the last time that a valid alarm came in), after voltages had begun deteriorating but well before any of FE's lines began to contact trees and trip out. After that time, the FE control room consoles did not receive any further alarms, nor were there any alarms being printed or posted on the EMS's alarm logging facilities. Power system operators rely heavily on audible and on-screen alarms, plus alarm logs, to reveal any significant changes in their system's conditions. After 14:14 EDT on August 14, FE's operators were working under a significant handicap without these tools. However, they were in further jeopardy because they did not know that they were operating without alarms, so that they did not realize that system conditions were changing.

Alarms are a critical function of an EMS, and EMS-generated alarms are the fundamental means by which system operators identify events on the power system that need their attention. Without alarms, events indicating one or more significant system changes can occur but remain undetected by the operator. If an EMS's alarms are absent, but operators are aware of the situation and the remainder of the EMS's functions are intact, the operators can potentially continue to use the EMS to monitor and exercise control of their power system. In such circumstances, the operators would have to do so via repetitive, continuous manual scanning of numerous data and status points located within the multitude of individual displays available within their EMS. Further, it would be difficult for the operator to identify quickly the most relevant of the many screens available.

In the same way that an alarm system can inform operators about the failure of key grid facilities, it can also be set up to alarm them if the alarm system itself fails to perform properly. FE's EMS did not have such a notification system.

Although the alarm processing function of FE's EMS failed, the remainder of that system generally continued to collect valid real-time status information and measurements about FE's power system, and continued to have supervisory control over the FE system. The EMS also continued to send its normal and expected collection of information on to other monitoring points and authorities, including MISO and AEP. Thus these entities continued to receive accurate information about the status and condition of FE's power system after the time when FE's EMS alarms failed. FE's operators were unaware that in this situation they needed to manually and more closely monitor and interpret the SCADA information they were receiving. Continuing on in the belief that their system was satisfactory, lacking any alarms from their EMS to the contrary, and without visualization aids such as a dynamic map board or a projection of system topology, FE control room operators were subsequently surprised when they began receiving telephone calls from other locations and information sources—MISO, AEP, PJM, and FE field operations staff—who offered information on the status of FE's transmission facilities that conflicted with FE's system operators' understanding of the situation.

Recommendations
3, page 143, 22, page 159

Analysis of the alarm problem performed by FE suggests that the alarm process essentially "stalled" while processing an alarm event, such that the process began to run in a manner that failed to complete the processing of that alarm or

Alarms

System operators must keep a close and constant watch on the multitude of things occurring simultaneously on their power system. These include the system's load, the generation and supply resources to meet that load, available reserves, and measurements of critical power system states, such as the voltage levels on the lines. Because it is not humanly possible to watch and understand all these events and conditions simultaneously, Energy Management Systems use alarms to bring relevant information to operators' attention. The alarms draw on the information collected by the SCADA real-time monitoring system.

Alarms are designed to quickly and appropriately attract the power system operators' attention to events or developments of interest on the system. They do so using combinations of audible and visual signals, such as sounds at operators' control desks and symbol or color changes or animations on system monitors, displays, or map boards. EMS alarms for power systems are similar to the indicator lights or warning bell tones that a modern automobile uses to signal its driver, like the "door open" bell, an image of a headlight high beam, a "parking brake on" indicator, and the visual and audible alert when a gas tank is almost empty.

Power systems, like cars, use "status" alarms and "limit" alarms. A status alarm indicates the state of a monitored device. In power systems these are commonly used to indicate whether such items as switches or breakers are "open" or "closed" (off or on) when they should be otherwise, or whether they have changed condition since the last scan. These alarms should provide clear indication and notification to system operators of whether a given device is doing what they think it is, or what they want it to do—for instance, whether a given power line is connected to the system and moving power at a particular moment.

EMS limit alarms are designed to provide an indication to system operators when something important that is measured on a power system device—such as the voltage on a line or the amount of power flowing across it—is below or above pre-specified limits for using that device safely and efficiently. When a limit alarm activates, it provides an important early warning to the power system operator that elements of the system may need some adjustment to prevent damage to the system or to customer loads—like the "low fuel" or "high engine temperature" warnings in a car.

When FE's alarm system failed on August 14, its operators were running a complex power system without adequate indicators of when key elements of that system were reaching and passing the limits of safe operation—and without awareness that they were running the system without these alarms and should no longer assume that not getting alarms meant that system conditions were still safe and unchanging.

produce any other valid output (alarms). In the meantime, new inputs—system condition data that needed to be reviewed for possible alarms—built up in and then overflowed the process' input buffers.[9,10]

Loss of Remote EMS Terminals. Between 14:20 EDT and 14:25 EDT, some of FE's remote EMS terminals in substations ceased operation. FE has advised the investigation team that it believes this occurred because the data feeding into those terminals started "queuing" and overloading the terminals' buffers. FE's system operators did not learn about this failure until 14:36 EDT, when a technician at one of the sites noticed the terminal was not working after he came in on the 15:00 shift, and called the main control room to report the problem. As remote terminals failed, each triggered an automatic page to FE's Information Technology (IT) staff.[11] The investigation team has not determined why some terminals failed whereas others did not. Transcripts indicate that data links to the remote sites were down as well.[12]

EMS Server Failures. FE's EMS system includes several server nodes that perform the higher functions of the EMS. Although any one of them can host all of the functions, FE's normal system configuration is to have a number of host subsets of the applications, with one server remaining in a "hot-standby" mode as a backup to the others should any fail. At 14:41 EDT, the primary server hosting the EMS alarm processing application failed, due either to the stalling of the alarm application, "queuing" to the remote EMS terminals, or some combination of the two. Following preprogrammed instructions, the alarm system application and all other EMS software running on the first server automatically transferred ("failed-over") onto the back-up server. However, because the alarm application moved intact onto the backup while still stalled and ineffective, the backup server failed 13 minutes later, at 14:54 EDT. Accordingly, all of the EMS applications on these two servers stopped running.

Recommendation 22, page 159

Cause 2
Inadequate Situational Awareness

The concurrent loss of both EMS servers apparently caused several new problems for FE's EMS and the operators who used it. Tests run during FE's after-the-fact analysis of the alarm failure event indicate that a concurrent absence of these servers can significantly slow down the rate at which the EMS system puts new—or refreshes existing—displays on operators' computer consoles. Thus at times on August 14th, operators' screen refresh rates—the rate at which new information and displays are painted onto the computer screen, normally 1 to 3 seconds—slowed to as long as 59 seconds per screen. Since FE operators have numerous information screen options, and one or more screens are commonly "nested" as sub-screens to one or more top level screens, operators' ability to view, understand and operate their system through the EMS would have slowed to a frustrating crawl.[13] This situation may have occurred between 14:54 EDT and 15:08 EDT when both servers failed, and again between 15:46 EDT and 15:59 EDT while FE's IT personnel attempted to reboot both servers to remedy the alarm problem.

Loss of the first server caused an auto-page to be issued to alert FE's EMS IT support personnel to the problem. When the back-up server failed, it too sent an auto-page to FE's IT staff. They did not notify control room operators of the problem. At 15:08 EDT, IT staffers completed a "warm reboot" (restart) of the primary server. Startup diagnostics monitored during that reboot verified that the computer and all expected processes were running; accordingly, FE's IT staff believed that they had successfully restarted the node and all the processes it was hosting. However, although the server and its applications were again running, the alarm system remained frozen and non-functional, even on the restarted computer. The IT staff did not confirm that the alarm system was again working properly with the control room operators.

Recommendation 19, page 156

Another casualty of the loss of both servers was the Automatic Generation Control (AGC) function hosted on those computers. Loss of AGC meant that FE's operators could not run affiliated power plants on pre-set programs to respond automatically to meet FE's system load and interchange obligations. Although the AGC did not work from 14:54 EDT to 15:08 EDT and 15:46 EDT to 15:59 EDT (periods when both servers were down), this loss of function does not appear to have had an effect on the blackout.

Recommendation 22, page 159

Cause 2
Inadequate Situational Awareness

The concurrent loss of the EMS servers also caused the failure of FE's strip chart function. There are many strip charts in the FE Reliability Operator control room driven by the EMS computers, showing a variety of system conditions, including raw ACE (Area Control Error), FE system load, and Sammis-South Canton and South Canton-Star loading. These charts are visible in the reliability operator control room. The chart printers continued to scroll but because the underlying computer system was locked up the chart pens showed only the last valid measurement recorded, without any variation from that measurement as time progressed (i.e., the charts "flat-lined"). There is no indication that any operators noticed or reported the failed operation of the charts.[14] The few charts fed by direct analog telemetry, rather than the EMS system, showed primarily frequency data, and remained available throughout the afternoon of August 14. These yield little useful system information for operational purposes.

FE's Area Control Error (ACE), the primary control signal used to adjust generators and imports to match load obligations, did not function between 14:54 EDT and 15:08 EDT and later between 15:46 EDT and 15:59 EDT, when the two servers were down. This meant that generators were not controlled during these periods to meet FE's load and interchange obligations (except from 15:00 EDT to 15:09 EDT when control was switched to a backup controller). There were no apparent negative consequences from this failure. It has not been established how loss of the primary generation control signal was identified or if any discussions occurred with respect to the computer system's operational status.[15]

EMS System History. The EMS in service at FE's Ohio control center is a GE Harris (now GE Network Systems) XA21 system. It was initially brought into service in 1995. Other than the application of minor software fixes or patches typically encountered in the ongoing maintenance and support of such a system, the last major updates or revisions to this EMS were implemented in 1998. On August 14 the system was not running the most current release of the XA21 software. FE had

Who Saw What?

What data and tools did others have to monitor the conditions on the FE system?

Midwest ISO (MISO), reliability coordinator for FE

Alarms: MISO received indications of breaker trips in FE that registered in MISO's alarms; however, the alarms were missed. These alarms require a look-up to link the flagged breaker with the associated line or equipment and unless this line was specifically monitored, require another look-up to link the line to the monitored flowgate. MISO operators did not have the capability to click on the on-screen alarm indicator to display the underlying information.

Real Time Contingency Analysis (RTCA): The contingency analysis showed several hundred violations around 15:00 EDT. This included some FE violations, which MISO (FE's reliability coordinator) operators discussed with PJM (AEP's Reliability Coordinator).[a] Simulations developed for this investigation show that violations for a contingency would have occurred after the Harding-Chamberlin trip at 15:05 EDT. There is no indication that MISO addressed this issue. It is not known whether MISO identified the developing Sammis-Star problem.

Flowgate Monitoring Tool: While an inaccuracy has been identified with regard to this tool it still functioned with reasonable accuracy and prompted MISO to call FE to discuss the Hanna-Juniper line problem. It would not have identified problems south of Star since that was not part of the flowgate and thus not modeled in MISO's flowgate monitor.

AEP

Contingency Analysis: According to interviews,[b] AEP had contingency analysis that covered lines into Star. The AEP operator identified a problem for Star-South Canton overloads for a Sammis-Star line loss about 15:33 EDT and asked PJM to develop TLRs for this. However, due to the size of the requested TLR, this was not implemented before the line tripped out of service.

Alarms: Since a number of lines cross between AEP's and FE's systems, they had the ability at their respective end of each line to identify contingencies that would affect both. AEP initially noticed FE line problems with the first and subsequent trips of the Star-South Canton 345-kV line, and called FE three times between 14:35 EDT and 15:45 EDT to determine whether FE knew the cause of the outage.[c]

[a] "MISO Site Visit," Benbow interview.
[b] "AEP Site Visit," Ulrich interview.
[c] Example at 14:35, Channel 4; 15:19, Channel 4; 15:45, Channel 14 (FE transcripts).

decided well before August 14 to replace it with one from another vendor.

Recommendation 33, page 164

FE personnel told the investigation team that the alarm processing application had failed on occasions prior to August 14, leading to loss of the alarming of system conditions and events for FE's operators.[16] However, FE said that the mode and behavior of this particular failure event were both first time occurrences and ones which, at the time, FE's IT personnel neither recognized nor knew how to correct. FE staff told investigators that it was only during a post-outage support call with GE late on 14 August that FE and GE determined that the only available course of action to correct the alarm problem was a "cold reboot"[17] of FE's overall XA21 system. In interviews immediately after the blackout, FE IT personnel indicated that they discussed a cold reboot of the XA21 system with control room operators after they were told of the alarm problem at 15:42 EDT, but decided not to take such action because operators considered power system conditions precarious, were concerned about the length of time that the reboot might take to complete, and understood that a cold reboot would leave them with even less EMS functionality until it was completed.[18]

Clues to the EMS Problems. There is an entry in FE's western desk operator's log at 14:14 EDT referring to the loss of alarms, but it is not clear whether that entry was made at that time or subsequently, referring back to the last known alarm. There is no indication that the operator mentioned the problem to other control room staff and supervisors or to FE's IT staff.

Recommendation 26, page 161

The first clear hint to FE control room staff of any computer problems occurred at 14:19 EDT when a caller and an FE control room operator discussed the fact that three sub-transmission center dial-ups had failed.[19] At 14:25 EDT, a control room operator talked with a caller about the failure of these three remote EMS consoles.[20] The next hint came at 14:32 EDT, when FE scheduling staff spoke about having made schedule changes to update the EMS pages, but that the totals did not update.[21]

Cause 2
Inadequate Situational Awareness

Although FE's IT staff would have been aware that concurrent loss of its servers would mean the loss of alarm processing on the EMS, the investigation team has found no indication that the IT staff informed the control room staff either when they began work on the servers at 14:54 EDT, or when they completed the primary server restart at 15:08 EDT. At 15:42 EDT, the IT staff were first told of the alarm problem by a control room operator; FE has stated to investigators that their IT staff had been unaware before then that the alarm processing sub-system of the EMS was not working.

Without the EMS systems, the only remaining ways to monitor system conditions would have been through telephone calls and direct analog telemetry. FE control room personnel did not realize that alarm processing on their EMS was not working and, subsequently, did not monitor other available telemetry.

Cause 2
Inadequate Situational Awareness

During the afternoon of August 14, FE operators talked to their field personnel, MISO, PJM (concerning an adjoining system in PJM's reliability coordination region), adjoining systems (such as AEP), and customers. The FE operators received pertinent information from all these sources, but did not recognize the emerging problems from the clues offered. This pertinent information included calls such as that from FE's eastern control center asking about possible line trips, FE Perry nuclear plant calls regarding what looked like nearby line trips, AEP calling about their end of the Star-South Canton line tripping, and MISO and PJM calling about possible line overloads.

Recommendations 19, page 156; 26, page 161

Without a functioning alarm system, the FE control area operators failed to detect the tripping of electrical facilities essential to maintain the security of their control area. Unaware of the loss of alarms and a limited EMS, they made no alternate arrangements to monitor the system. When AEP identified the 14:27 EDT circuit trip and reclosure of the Star 345 kV line circuit breakers at AEP's South Canton substation, the FE operator dismissed the information as either not accurate or not relevant to his system, without following up on the discrepancy between the AEP event and the information from his own tools. There was no subsequent verification of conditions with the MISO reliability coordinator.

Only after AEP notified FE that a 345-kV circuit had tripped and locked out did the FE control area operator compare this information to actual breaker conditions. FE failed to inform its reliability coordinator and adjacent control areas when they became aware that system conditions had changed due to unscheduled equipment outages that might affect other control areas.

Recommendations
26, page 161; 30, page 163

Phase 3: Three FE 345-kV Transmission Line Failures and Many Phone Calls: 15:05 EDT to 15:57 EDT

Overview of This Phase

From 15:05:41 EDT to 15:41:35 EDT, three 345-kV lines failed with power flows at or below each transmission line's emergency rating. These line trips were not random. Rather, each was the result of a contact between a line and a tree that had grown so tall that, over a period of years, it encroached into the required clearance height for the line. As each line failed, its outage increased the loading on the remaining lines (Figure 5.5). As each of the transmission lines failed, and power flows shifted to other transmission paths, voltages on the rest of FE's system degraded further (Figure 5.6).

Key Phase 3 Events

3A) 15:05:41 EDT: Harding-Chamberlin 345-kV line tripped.

3B) 15:31-33 EDT: MISO called PJM to determine if PJM had seen the Stuart-Atlanta 345-kV line outage. PJM confirmed Stuart-Atlanta was out.

3C) 15:32:03 EDT: Hanna-Juniper 345-kV line tripped.

3D) 15:35 EDT: AEP asked PJM to begin work on a 350-MW TLR to relieve overloading on the Star-South Canton line, not knowing the Hanna-Juniper 345-kV line had already tripped at 15:32 EDT.

3E) 15:36 EDT: MISO called FE regarding post-contingency overload on Star-Juniper 345-kV line for the contingency loss of the Hanna-Juniper 345-kV line, unaware at the start of the call that Hanna-Juniper had already tripped.

3F) 15:41:33-41 EDT: Star-South Canton 345-kV tripped, reclosed, tripped again at 15:41:35 EDT and remained out of service, all while AEP and PJM were discussing TLR relief options (event 3D).

Transmission lines are designed with the expectation that they will sag lower when they become hotter. The transmission line gets hotter with heavier line loading and under higher ambient temperatures, so towers and conductors are designed to be tall enough and conductors pulled tightly enough to accommodate expected sagging and still meet safety requirements. On a summer day, conductor temperatures can rise from 60°C on mornings with average wind to 100°C with hot air temperatures and low wind conditions.

A short-circuit occurred on the Harding-Chamberlin 345-kV line due to a contact between the line conductor and a tree. This line failed with power flow at only 44% of its normal and emergency line rating. Incremental line current and temperature increases, escalated by the loss of Harding-Chamberlin, caused more sag on the Hanna-Juniper line, which contacted a tree and failed with power flow at 88% of its normal and emergency line rating. Star-South Canton

Figure 5.5. FirstEnergy 345-kV Line Flows

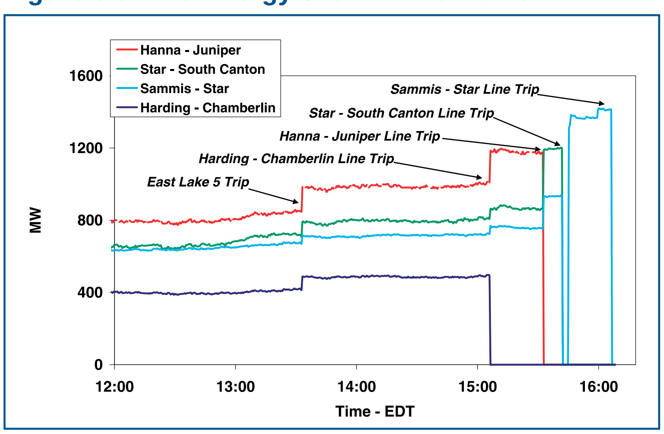


Figure 5.6. Voltages on FirstEnergy's 345-kV Lines: Impacts of Line Trips

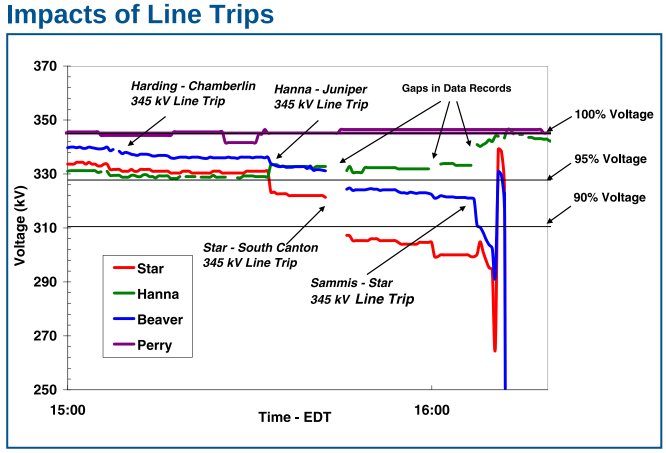
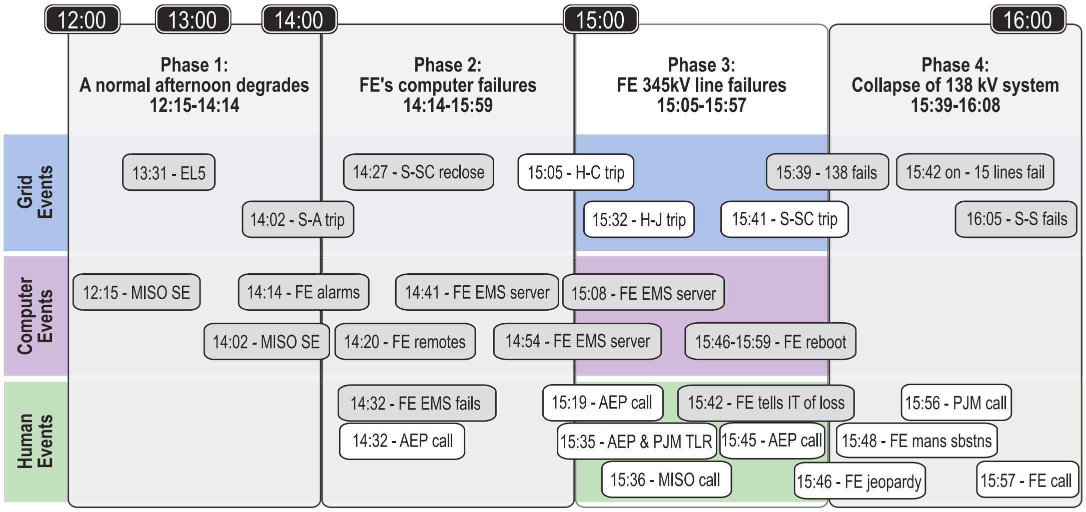


Figure 5.7. Timeline Phase 3



contacted a tree three times between 14:27:15 EDT and 15:41:33 EDT, opening and reclosing each time before finally locking out while loaded at 93% of its emergency rating at 15:41:35 EDT. Each of these three lines tripped not because of excessive sag due to overloading or high conductor temperature, but because it hit an overgrown, untrimmed tree.[22]

Cause 3
Inadequate Tree Trimming

Overgrown trees, as opposed to excessive conductor sag, caused each of these faults. While sag may have contributed to these events, these incidents occurred because the trees grew too tall and encroached into the space below the line which is intended to be clear of any objects, not because the lines sagged into short trees. Because the trees were so tall (as discussed below), each of these lines faulted under system conditions well within specified operating parameters. The investigation team found field evidence of tree contact at all three locations, including human observation of the Hanna-Juniper contact. Evidence outlined below confirms that contact with trees caused the short circuits to ground that caused each line to trip out on August 14.

To be sure that the evidence of tree/line contacts and tree remains found at each site was linked to the events of August 14, the team looked at whether these lines had any prior history of outages in preceding months or years that might have resulted in the burn marks, debarking, and other vegetative evidence of line contacts. The record establishes that there were no prior sustained outages known to be caused by trees for these lines in 2001, 2002, and 2003.[23]

Like most transmission owners, FE patrols its lines regularly, flying over each transmission line twice a year to check on the condition of the rights-of-way. Notes from fly-overs in 2001 and 2002 indicate that the examiners saw a significant number of trees and brush that needed clearing or

Line Ratings

A conductor's normal rating reflects how heavily the line can be loaded under routine operation and keep its internal temperature below a certain temperature (such as 90°C). A conductor's emergency rating is often set to allow higher-than-normal power flows, but to limit its internal temperature to a maximum temperature (such as 100°C) for no longer than a specified period, so that it does not sag too low or cause excessive damage to the conductor.

For three of the four 345-kV lines that failed, FE set the normal and emergency ratings at the same level. Many of FE's lines are limited by the maximum temperature capability of its terminal equipment, rather than by the maximum safe temperature for its conductors. In calculating summer emergency ampacity ratings for many of its lines, FE assumed 90°F (32°C) ambient air temperatures and 6.3 ft/sec (1.9 m/sec) wind speed,[a] which is a relatively high wind speed assumption for favorable wind cooling. Actual temperature on August 14 was 87°F (31°C) but wind speed at certain locations in the Akron area was somewhere between 0 and 2 ft/sec (0.6 m/sec) after 15:00 EDT that afternoon.

[a]FirstEnergy Transmission Planning Criteria (Revision 8), page 3.

trimming along many FE transmission lines. Notes from fly-overs in the spring of 2003 found fewer problems, suggesting that fly-overs do not allow effective identification of the distance between a tree and the line above it, and need to be supplemented with ground patrols.

Recommendations
16, page 154; 27, page 162

3A) FE's Harding-Chamberlin 345-kV Line Tripped: 15:05 EDT

At 15:05:41 EDT, FE's Harding-Chamberlin line (Figure 5.8) tripped and locked out while loaded at 44% of its normal and emergency rating. At this low loading, the line temperature would not exceed safe levels—even if still air meant there

Utility Vegetation Management: When Trees and Lines Contact

Vegetation management is critical to any utility company that maintains overhead energized lines. It is important and relevant to the August 14 events because electric power outages occur when trees, or portions of trees, grow up or fall into overhead electric power lines. While not all outages can be prevented (due to storms, heavy winds, etc.), some outages can be mitigated or prevented by managing the vegetation before it becomes a problem. When a tree contacts a power line it causes a short circuit, which is read by the line's relays as a ground fault. Direct physical contact is not necessary for a short circuit to occur. An electric arc can occur between a part of a tree and a nearby high-voltage conductor if a sufficient distance separating them is not maintained. Arcing distances vary based on such factors such as voltage and ambient wind and temperature conditions. Arcs can cause fires as well as short circuits and line outages.

Most utilities have right-of-way and easement agreements allowing them to clear and maintain vegetation as needed along their lines to provide safe and reliable electric power. Transmission easements generally give the utility a great deal of control over the landscape, with extensive rights to do whatever work is required to maintain the lines with adequate clearance through the control of vegetation. The three principal means of managing vegetation along a transmission right-of-way are pruning the limbs adjacent to the line clearance zone, removing vegetation completely by mowing or cutting, and using herbicides to retard or kill further growth. It is common to see more tree and brush removal using mechanical and chemical tools and relatively less pruning along transmission rights-of-way.

FE's easement agreements establish extensive rights regarding what can be pruned or removed in these transmission rights-of-way, including: "the right to erect, inspect, operate, replace, relocate, repair, patrol and permanently maintain upon, over, under and along the above described right of way across said premises all necessary structures, wires, cables and other usual fixtures and appurtenances used for or in connection with the transmission and distribution of electric current, including telephone and telegraph, and the right to trim, cut, remove or control by any other means at any and all times such trees, limbs and underbrush within or adjacent to said right of way as may interfere with or endanger said structures, wires or appurtenances, or their operations."[a]

FE uses a 5-year cycle for transmission line vegetation maintenance (i.e., it completes all required vegetation work within a 5-year period for all circuits). A 5-year cycle is consistent with industry practices, and it is common for transmission providers not to fully exercise their easement rights on transmission rights-of-way due to landowner or land manager opposition.

A detailed study prepared for this investigation, "Utility Vegetation Management Final Report," concludes that although FirstEnergy's vegetation management practices are within common or average industry practices, those common industry practices need significant improvement to assure greater transmission reliability.[b] The report further recommends that strict regulatory oversight and support will be required for utilities to improve and sustain needed improvements in their vegetation management programs.

NERC has no standards or requirements for vegetation management or transmission right-of-way clearances, nor for the determination of line ratings.

[a]Standard language in FE's right-of-way easement agreement.
[b]"Utility Vegetation Management Final Report," CN Utility Consulting, March 2004.

Cause 3
Inadequate Tree Trimming

was no wind cooling of the conductor—and the line would not sag excessively. The investigation team examined the relay data for this trip, identified the geographic location of the fault, and determined that the relay data match the classic "signature" pattern for a tree/line short circuit to ground fault. The field team found the remains of trees and brush at the fault location determined from the relay data. At this location, conductor height measured 46 feet 7 inches (14.20 meters), while the height of the felled tree measured 42 feet (12.80 meters); however, portions of the tree had been removed from the site. This means that while it is difficult to determine the exact height of the line contact, the measured height is a minimum and the actual contact was likely 3 to 4 feet (0.9 to 1.2 meters) higher than estimated here. Burn marks were observed 35 feet 8 inches (10.87 meters) up the tree, and the crown of this tree was at least 6 feet (1.83 meters) taller than the observed burn marks. The tree showed evidence of fault current damage.[24]

Recommendations
16, page 154; 27, page 162

When the Harding-Chamberlin line locked out, the loss of this 345-kV path caused the remaining three southern 345-kV lines into Cleveland to pick up more load, with Hanna-Juniper picking up the most. The Harding-Chamberlin outage also caused more power to flow through the underlying 138-kV system.

Cause 2
Inadequate Situational Awareness

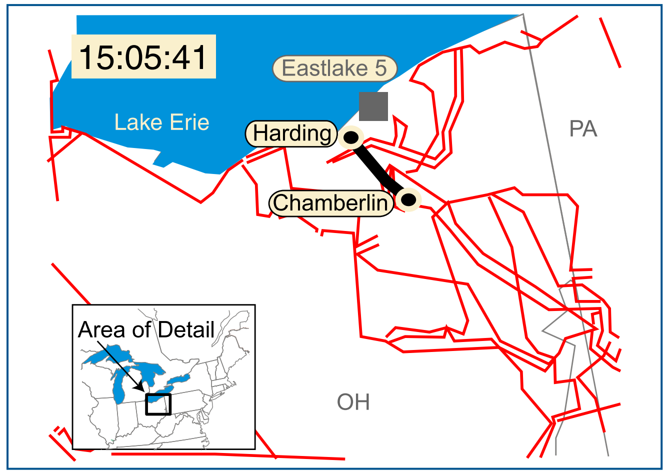
MISO did not discover that Harding-Chamberlin had tripped until after the blackout, when MISO reviewed the breaker operation log that evening. FE indicates that it discovered the line was out while investigating system conditions in response to MISO's call at 15:36 EDT, when MISO told FE that MISO's flowgate monitoring tool showed a Star-Juniper line overload following a contingency loss of Hanna-Juniper;[25] however, the investigation team has found no evidence within the control room logs or transcripts to show that FE knew of the Harding-Chamberlin line failure until after the blackout.

Recommendation
22, page 159

Cause 4
Inadequate RC Diagnostic Support

Harding-Chamberlin was not one of the flowgates that MISO monitored as a key transmission location, so the reliability coordinator was unaware when FE's first 345-kV line failed. Although MISO received

Figure 5.8. Harding-Chamberlin 345-kV Line



SCADA input of the line's status change, this was presented to MISO operators as breaker status changes rather than a line failure. Because their EMS system topology processor had not yet been linked to recognize line failures, it did not connect the breaker information to the loss of a transmission line. Thus, MISO's operators did not recognize the Harding-Chamberlin trip as a significant contingency event and could not advise FE regarding the event or its consequences. Further, without its state estimator and associated contingency analyses, MISO was unable to identify potential overloads that would occur due to various line or equipment outages. Accordingly, when the Harding-Chamberlin 345-kV line tripped at 15:05 EDT, the state estimator did not produce results and could not predict an overload if the Hanna-Juniper 345-kV line were to fail.

Recommendation
30, page 163

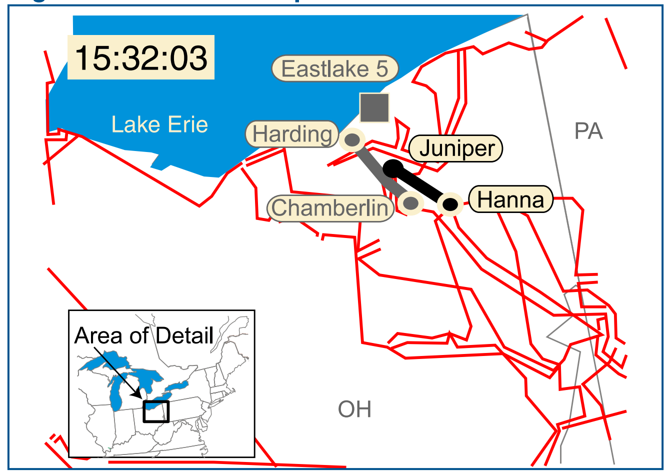
3C) FE's Hanna-Juniper 345-kV Line Tripped: 15:32 EDT

Cause 3
Inadequate Tree Trimming

At 15:32:03 EDT the Hanna-Juniper line (Figure 5.9) tripped and locked out. A tree-trimming crew was working nearby and observed the tree/line contact. The tree contact occurred on the south phase, which is lower than the center phase due to construction design. Although little evidence remained of the tree during the field team's visit in October, the team observed a tree stump 14 inches (35.5 cm) in diameter at its ground line and talked to an individual who witnessed the contact on August 14.[26] Photographs clearly indicate that the tree was of excessive height (Figure 5.10). Surrounding trees were 18 inches (45.7 cm) in diameter at ground line and 60 feet (18.3 meters) in height (not near lines). Other sites at this location had numerous (at least 20) trees in this right-of-way.

Hanna-Juniper was loaded at 88% of its normal and emergency rating when it tripped. With this line open, over 1,200 MVA of power flow had to find a new path to reach its load in Cleveland. Loading on the remaining two 345-kV lines increased, with Star-Juniper taking the bulk of the power. This caused Star-South Canton's loading to rise above its normal but within its emergency rating and pushed more power onto the 138-kV system. Flows west into Michigan decreased slightly and voltages declined somewhat in the Cleveland area.

Figure 5.9. Hanna-Juniper 345-kV Line

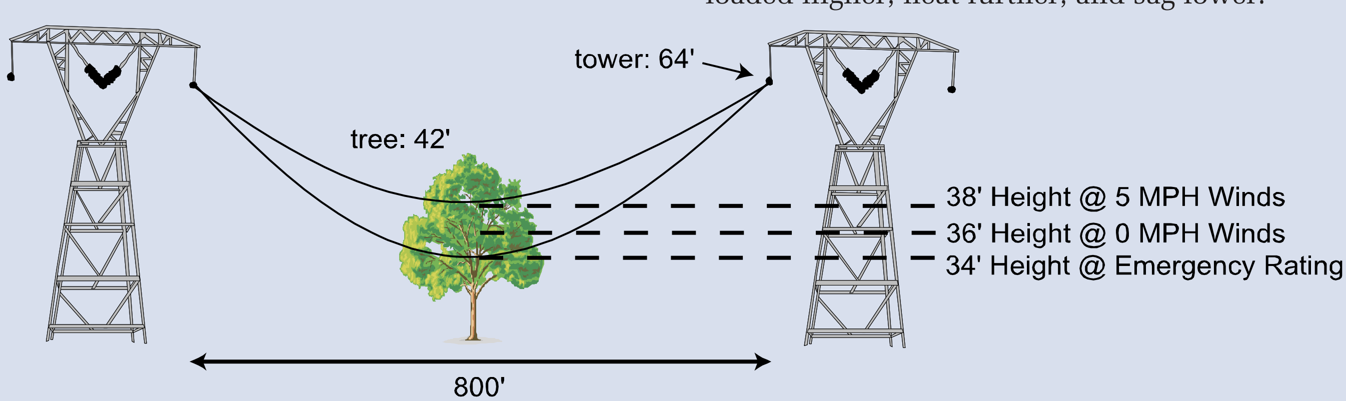


Why Did So Many Tree-to-Line Contacts Happen on August 14?

Tree-to-line contacts and resulting transmission outages are not unusual in the summer across much of North America. The phenomenon occurs because of a combination of events occurring particularly in late summer:

- Most tree growth occurs during the spring and summer months, so the later in the summer the taller the tree and the greater its potential to contact a nearby transmission line.
- As temperatures increase, customers use more air conditioning and load levels increase. Higher load levels increase flows on the transmission system, causing greater demands for both active power (MW) and reactive power (MVAr). Higher flow on a transmission line causes the line to heat up, and the hot line sags lower because the hot conductor metal expands. Most emergency line ratings are set to limit conductors' internal temperatures to no more than 100°C (212°F).
- As temperatures increase, ambient air temperatures provide less cooling for loaded transmission lines.
- Wind flows cool transmission lines by increasing the airflow of moving air across the line. On August 14 wind speeds at the Ohio Akron-Fulton airport averaged 5 knots (1.5 m/sec) at around 14:00 EDT, but by 15:00 EDT wind speeds had fallen to 2 knots (0.6 m/sec)—the wind speed commonly assumed in conductor design—or lower. With lower winds, the lines sagged further and closer to any tree limbs near the lines.

This combination of events on August 14 across much of Ohio and Indiana caused transmission lines to heat and sag. If a tree had grown into a power line's designed clearance area, then a tree/line contact was more likely, though not inevitable. An outage on one line would increase power flows on related lines, causing them to be loaded higher, heat further, and sag lower.



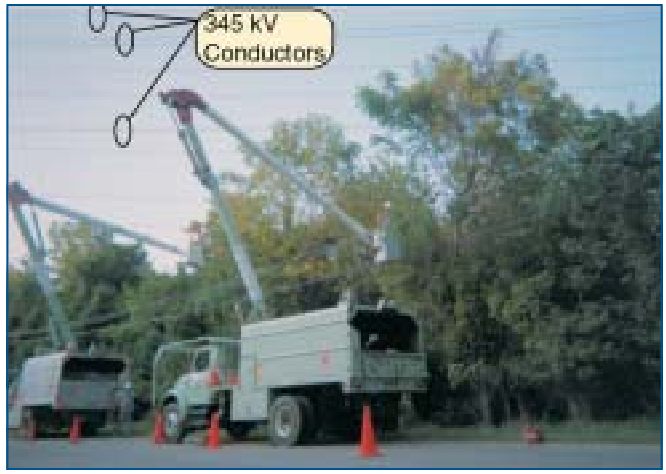
3D) AEP and PJM Begin Arranging a TLR for Star-South Canton: 15:35 EDT

Cause 4
Inadequate RC Diagnostic Support

Because its alarm system was not working, FE was not aware of the Harding-Chamberlin or Hanna-Juniper line trips. However, once MISO manually updated the state estimator model for the Stuart-Atlanta 345-kV line outage, the software successfully completed a state estimation and contingency analysis at 15:41 EDT. But this left a 36 minute period, from 15:05 EDT to 15:41 EDT, during which MISO did not recognize the consequences of the Hanna-Juniper loss, and FE operators knew neither of the line's loss nor its consequences. PJM and AEP recognized the overload on Star-South Canton, but had not expected it because their earlier contingency analysis did not examine enough lines within the FE system to foresee this result of the Hanna-Juniper contingency on top of the Harding-Chamberlin outage.

After AEP recognized the Star-South Canton overload, at 15:35 EDT AEP asked PJM to begin developing a 350 MW TLR to mitigate it. The TLR was to relieve the actual overload above normal rating then occurring on Star-South Canton, and prevent an overload above emergency rating on

Figure 5.10. Cause of the Hanna-Juniper Line Loss



This August 14 photo shows the tree that caused the loss of the Hanna-Juniper line (tallest tree in photo). Other 345-kV conductors and shield wires can be seen in the background. Photo by Nelson Tree.

Handling Emergencies by Shedding Load and Arranging TLRs

Transmission loading problems. Problems such as contingent overloads of normal ratings are typically handled by arranging Transmission Loading Relief (TLR) measures, which in most cases take effect as a schedule change 30 to 60 minutes after they are issued. Apart from a TLR level 6, TLRs are intended as a tool to prevent the system from being operated in an unreliable state,[a] and are not applicable in real-time emergency situations because it takes too long to implement reductions. Actual overloads and violations of stability limits need to be handled immediately under TLR level 4 or 6 by redispatching generation, system reconfiguration or tripping load. The dispatchers at FE, MISO and other control areas or reliability coordinators have authority—and under NERC operating policies, responsibility—to take such action, but the occasion to do so is relatively rare.

Lesser TLRs reduce scheduled transactions—non-firm first, then pro-rata between firm transactions, including flows that serve native load. When pre-contingent conditions are not solved with TLR levels 3 and 5, or conditions reach actual overloading or surpass stability limits, operators must use emergency generation redispatch and/or load-shedding under TLR level 6 to return to a secure state. After a secure state is reached, TLR level 3 and/or 5 can be initiated to relieve the emergency generation redispatch or load-shedding activation.

System operators and reliability coordinators, by NERC policy, have the responsibility and the authority to take actions up to and including emergency generation redispatch and shedding firm load to preserve system security. On August 14, because they either did not know or understand enough about system conditions at the time, system operators at FE, MISO, PJM, or AEP did not call for emergency actions.

Use of automatic procedures in voltage-related emergencies. There are few automatic safety nets in place in northern Ohio except for under-frequency load-shedding in some locations. In some utility systems in the U.S. Northeast, Ontario, and parts of the Western Interconnection, special protection systems or remedial action schemes, such as under-voltage load-shedding are used to shed load under defined severe contingency conditions similar to those that occurred in northern Ohio on August 14.

[a]"Northern MAPP/Northwestern Ontario Disturbance-June 25, 1998," NERC 1998 Disturbance Report, page 17.

that line if the Sammis-Star line were to fail. But when they began working on the TLR, neither AEP nor PJM realized that the Hanna-Juniper 345-kV line had already tripped at 15:32 EDT, further degrading system conditions. Since the great majority of TLRs are for cuts of 25 to 50 MW, a 350 MW TLR request was highly unusual and operators were attempting to confirm why so much relief was suddenly required before implementing the requested TLR. Less than ten minutes elapsed between the loss of Hanna-Juniper, the overload above the normal limits of Star-South Canton, and the Star-South Canton trip and lock-out.

Recommendations
6, page 147; 22, page 159; 30, page 163; 31, page 163

Cause 2
Inadequate Situational Awareness

Unfortunately, neither AEP nor PJM recognized that even a 350 MW TLR on the Star-South Canton line would have had little impact on the overload. Investigation team analysis using the Interchange Distribution Calculator (which was fully available on the afternoon of August 14) indicates that tagged transactions for the 15:00 EDT hour across Ohio had minimal impact on the overloaded lines. As discussed in Chapter 4, this analysis showed that after the loss of the Hanna-Juniper 345 kV line, Star-South Canton was loaded primarily with flows to serve native and network loads, delivering makeup energy for the loss of Eastlake 5, purchased from PJM (342 MW) and Ameren (126 MW). The only way that these high loadings could have been relieved would not have been from the redispatch that AEP requested, but rather from significant load-shedding by FE in the Cleveland area.

Cause 4
Inadequate RC Diagnostic Support

The primary tool MISO uses for assessing reliability on key flowgates (specified groupings of transmission lines or equipment that sometimes have less transfer capability than desired) is the flowgate monitoring tool. After the Harding-Chamberlin 345-kV line outage at 15:05 EDT, the flowgate monitoring tool produced incorrect (obsolete) results, because the outage was not reflected in the model. As a result, the tool assumed that Harding-Chamberlin was still available and did not predict an overload for loss of the Hanna-Juniper 345-kV line. When Hanna-Juniper tripped at 15:32 EDT, the resulting overload was detected by MISO's SCADA and set off alarms to MISO's system operators, who then phoned FE about it.[27] Because both MISO's state estimator and its flowgate monitoring tool were not working properly, MISO's ability to recognize FE's evolving contingency situation was impaired.

Recommendations
22, page 159; 30, page 163

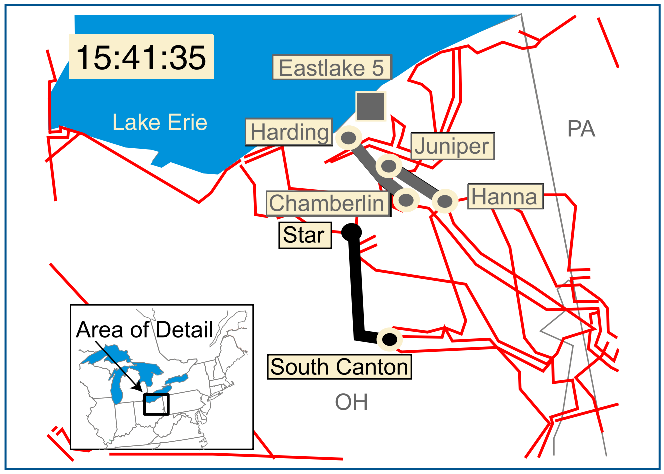
3F) Loss of the Star-South Canton 345-kV Line: 15:41 EDT

The Star-South Canton line (Figure 5.11) crosses the boundary between FE and AEP—each company owns the portion of the line and manages the right-of-way within its respective territory. The Star-South Canton line tripped and reclosed three times on the afternoon of August 14, first at 14:27:15 EDT while carrying less than 55% of its emergency rating (reclosing at both ends), then at 15:38:48 and again at 15:41:33 EDT. These multiple contacts had the effect of "electric tree-trimming," burning back the contacting limbs temporarily and allowing the line to carry more current until further sag in the still air caused the final contact and lock-out. At 15:41:35 EDT the line tripped and locked out at the Star substation, with power flow at 93% of its emergency rating. A short-circuit to ground occurred in each case.

Cause 3
Inadequate Tree Trimming

The investigation's field team inspected the right of way in the location indicated by the relay digital fault recorders, in the FE portion of the line. They found debris from trees and vegetation that had been felled. At this location the conductor height was 44 feet 9 inches (13.6 meters). The identifiable tree remains measured 30 feet (9.1 meters) in height, although the team could not verify the location of the stump, nor find all sections of the tree. A nearby cluster of trees showed significant fault damage, including charred limbs and de-barking from fault current. Further, topsoil in

Figure 5.11. Star-South Canton 345-kV Line



the area of the tree trunk was disturbed, discolored and broken up, a common indication of a higher magnitude fault or multiple faults. Analysis of another stump showed that a fourteen year-old tree had recently been removed from the middle of the right-of-way.[28]

Recommendations
16, page 154; 27, page 162

After the Star-South Canton line was lost, flows increased greatly on the 138-kV system toward Cleveland and area voltage levels began to degrade on the 138-kV and 69-kV system. At the same time, power flows increased on the Sammis-Star 345-kV line due to the 138-kV line trips—the only remaining paths into Cleveland from the south.

Cause 2
Inadequate Situational Awareness

FE's operators were not aware that the system was operating outside first contingency limits after the Harding-Chamberlin trip (for the possible loss of Hanna-Juniper or the Perry unit), because they did not conduct a contingency analysis.[29] The investigation team has not determined whether the system status information used by FE's state estimator and contingency analysis model was being accurately updated.

Recommendation
22, page159

Cause 1
Inadequate System Understanding

Load-Shed Analysis. The investigation team looked at whether it would have been possible to prevent the blackout by shedding load within the Cleveland-Akron area before the Star-South Canton 345 kV line tripped at 15:41 EDT. The team modeled the system assuming 500 MW of load shed within the Cleveland-Akron area before 15:41 EDT and found that this would have improved voltage at the Star bus from 91.7% up to 95.6%, pulling the line loading from 91 to 87% of its emergency ampere rating; an additional 500 MW of load would have had to be dropped to improve Star voltage to 96.6% and the line loading to 81% of its emergency ampere rating. But since the Star-South Canton line had already been compromised by the tree below it (which caused the first two trips and reclosures), and was about to trip from tree contact a third time, it is not clear that had such load shedding occurred, it would have prevented the ultimate trip and lock-out of the line. However, modeling indicates that this load shed would have prevented the subsequent tripping of the Sammis-Star line (see page 70).

Recommendations
8, page 147; 21, page 158

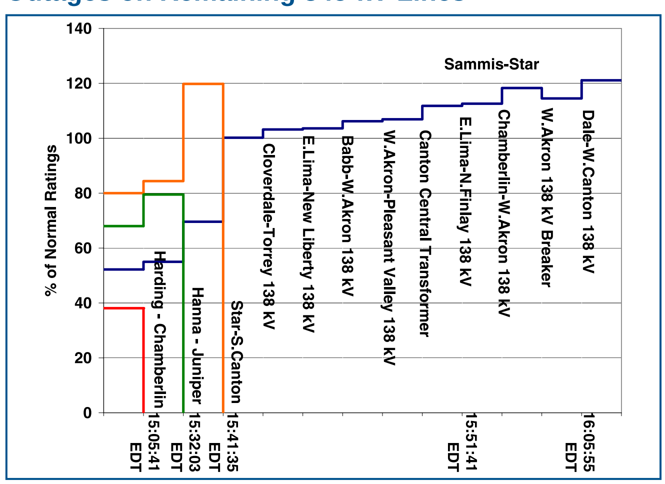
Cause 2
Inadequate Situational Awareness

System impacts of the 345-kV failures. According to extensive investigation team modeling, there were no contingency limit violations as of 15:05 EDT before the loss of the Harding-Chamberlin 345-kV line. Figure 5.12 shows the line loadings estimated by investigation team modeling as the 345-kV lines in northeast Ohio began to trip. Showing line loadings on the 345-kV lines as a percent of normal rating, it tracks how the loading on each line increased as each subsequent 345-kV and 138-kV line tripped out of service between 15:05 EDT (Harding-Chamberlin, the first line above to stair-step down) and 16:06 EDT (Dale-West Canton). As the graph shows, none of the 345- or 138-kV lines exceeded their normal ratings until after the combined trips of Harding-Chamberlin and Hanna-Juniper. But immediately after the second line was lost, Star-South Canton's loading jumped from an estimated 82% of normal to 120% of normal (which was still below its emergency rating) and remained at the 120% level for 10 minutes before tripping out. To the right, the graph shows the effects of the 138-kV line failures (discussed in the next phase) upon the two remaining 345-kV lines—i.e., Sammis-Star's loading increased steadily above 100% with each succeeding 138-kV line lost.

Following the loss of the Harding-Chamberlin 345-kV line at 15:05 EDT, contingency limit violations existed for:

- The Star-Juniper 345-kV line, whose loadings would exceed emergency limits if the Hanna-Juniper 345-kV line were lost; and

Figure 5.12. Cumulative Effects of Sequential Outages on Remaining 345-kV Lines



- The Hanna-Juniper and Harding-Juniper 345-kV lines, whose loadings would exceed emergency limits if the Perry generation unit (1,255 MW) were lost.

Operationally, once FE's system entered an N-1 contingency violation state, any facility loss beyond that pushed them farther into violation and into a more unreliable state. After loss of the Harding-Chamberlin line, to avoid violating NERC criteria, FE needed to reduce loading on these three lines within 30 minutes such that no single contingency would violate an emergency limit; that is, to restore the system to a reliable operating mode.

Phone Calls into the FE Control Room

Cause 2
Inadequate Situational Awareness

Beginning at 14:14 EDT when their EMS alarms failed, and until at least 15:42 EDT when they began to recognize their situation, FE operators did not understand how much of their system was being lost, and did not realize the degree to which their perception of their system was in error versus true system conditions, despite receiving clues via phone calls from AEP, PJM and MISO, and customers. The FE operators were not aware of line outages that occurred after the trip of Eastlake 5 at 13:31 EDT until approximately 15:45 EDT, although they were beginning to get external input describing aspects of the system's weakening condition. Since FE's operators were not aware and did not recognize events as they were occurring, they took no actions to return the system to a reliable state.

Recommendations
19, page 156; 26, page 161

A brief description follows of some of the calls FE operators received concerning system problems and their failure to recognize that the problem was on their system. For ease of presentation, this set of calls extends past the time of the 345-kV line trips into the time covered in the next phase, when the 138-kV system collapsed.

Following the first trip of the Star-South Canton 345-kV line at 14:27 EDT, AEP called FE at 14:32 EDT to discuss the trip and reclose of the line. AEP was aware of breaker operations at their end (South Canton) and asked about operations at FE's Star end. FE indicated they had seen nothing at their end of the line, but AEP reiterated that the trip occurred at 14:27 EDT and that the South Canton breakers had reclosed successfully.[30] There was an internal FE conversation about the AEP call at 14:51 EDT, expressing concern that they had not seen any indication of an operation, but lacking evidence within their control room, the FE operators did not pursue the issue.

At 15:19 EDT, AEP called FE back to confirm that the Star-South Canton trip had occurred and that AEP had a confirmed relay operation from the site. FE's operator restated that because they had received no trouble or alarms, they saw no problem. An AEP technician at the South Canton substation verified the trip. At 15:20 EDT, AEP decided to treat the South Canton digital fault recorder and relay target information as a "fluke," and checked the carrier relays to determine what the problem might be.[31]

At 15:35 EDT the FE control center received a call from the Mansfield 2 plant operator concerned about generator fault recorder triggers and excitation voltage spikes with an alarm for over-excitation, and a dispatcher called reporting a "bump" on their system. Soon after this call, 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."[32]

Beginning at this time, the FE operators began to think that something was wrong, but did not recognize that it was on their system. "It's got to be in distribution, or something like that, or somebody else's problem . . . but I'm not showing anything."[33] Unlike many other transmission grid control rooms, FE's control center did not have a map board (which shows schematically all major lines and plants in the control area on the wall in front of the operators), which might have shown the location of significant line and facility outages within the control area.

Recommendation
22, page 159

At 15:36 EDT, MISO contacted FE regarding the post-contingency overload on Star-Juniper for the loss of the Hanna-Juniper 345-kV line.[34]

At 15:42 EDT, FE's western transmission operator informed FE's IT 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 the first evidence that a member of FE's control room staff recognized any aspect of their degraded EMS system. There is no indication that he informed any of the other operators at this moment. However, FE's IT staff discussed the subsequent EMS alarm corrective action with some control room staff shortly thereafter.

Also at 15:42 EDT, 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."[35]

At 15:45 EDT, the 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.[36]

After the Star-South Canton 345-kV line tripped a third time and locked out at 15:41:35 EDT, AEP called FE at 15:45 EDT to discuss and inform them that they had additional lines that showed overload. FE recognized then that the Star breakers had tripped and remained open.[37]

At 15:46 EDT 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."[38]

At 15:48 EDT, an FE transmission operator sent staff to man the Star substation, and then at 15:50 EDT, requested staffing at the regions, beginning with Beaver, then East Springfield.[39]

At 15:48 EDT, PJM called MISO to report the Star-South Canton trip, but the two reliability coordinators' measures of the resulting line flows on FE's Sammis-Star 345-kV line did not match, causing them to wonder whether the Star-South Canton 345-kV line had returned to service.[40]

At 15:56 EDT, because PJM was still concerned about the impact of the Star-South Canton trip, PJM called FE to report that Star-South Canton had tripped and that PJM thought FE's Sammis-Star line was in actual emergency limit overload.[41] FE could not confirm this overload. FE informed PJM that Hanna-Juniper was also out service. FE believed that the problems existed beyond their system. "AEP must have lost some major stuff."[42]

Emergency Action

For FirstEnergy, as with many utilities, emergency awareness is often focused on energy shortages. Utilities have plans to reduce loads under these circumstances to increasingly greater degrees. Tools include calling for contracted customer load reductions, then public appeals, voltage reductions, and finally shedding system load by cutting off interruptible and firm customers. FE has a plan for this that is updated yearly. While they can trip loads quickly where there is SCADA control of load breakers (although FE has few of these), from an energy point of view, the intent is to be able to regularly rotate what loads are not being served, which requires calling personnel out to switch the various groupings in and out. This event was not, however, a capacity or energy emergency or system instability, but an emergency due to transmission line overloads.

To handle an emergency effectively a dispatcher must first identify the emergency situation and then determine effective action. AEP identified potential contingency overloads at 15:36 EDT and called PJM even as Star-South Canton, one of the AEP/FE lines they were discussing, tripped and pushed FE's Sammis-Star 345-kV line to its emergency rating. Since they had been focused on the impact of a Sammis-Star loss overloading Star-South Canton, they recognized that a serious problem had arisen on the system for which they did not have a ready solution. Later, around 15:50 EDT, their conversation reflected emergency conditions (138-kV lines were tripping and several other lines overloaded) but they still found no practical way to mitigate these overloads across utility and reliability coordinator boundaries.

Recommendation 20, page 158

Cause 2
Inadequate Situational Awareness

At the control area level, FE remained unaware of the precarious condition its system was in, with key lines out of service, degrading voltages, and severe overloads on their remaining lines. Transcripts show that FE operators were aware of falling voltages and customer problems after loss of the Hanna-Juniper 345-kV line (at 15:32 EDT). They called out personnel to staff substations because they did not think they could see them with their data gathering tools. They were also talking to customers. But there is no indication that FE's operators clearly identified their situation as a possible emergency until around 15:45 EDT when the shift supervisor informed his manager that it looked as if they were losing the system; even then, although FE had grasped that its system was in trouble, it never officially declared that it was an emergency condition and that emergency or extraordinary action was needed.

FE's internal control room procedures and protocols did not prepare it adequately to identify and react to the August 14 emergency. Throughout the afternoon of August 14 there were many clues that FE had lost both its critical monitoring alarm functionality and that its transmission system's reliability was becoming progressively more compromised. However, FE did not fully piece these clues together until after it had already lost critical elements of its transmission system and only minutes before subsequent trips triggered the cascade phase of the blackout. The clues to a compromised EMS alarm system and transmission system came into the FE control room from FE customers, generators, AEP, MISO, and PJM. In spite of these clues, because of a number of related factors, FE failed to identify the emergency that it faced.

Recommendations
20, page 158; 22, page 159; 26, page 161

Cause 2
Inadequate Situational Awareness

The most critical factor delaying the assessment and synthesis of the clues was a lack of information sharing between the FE system operators. In interviews with the FE operators and analysis of phone transcripts, it is evident that rarely were any of the critical clues shared with fellow operators. This lack of information sharing can be attributed to:

Recommendation
26, page 161

1. Physical separation of operators (the reliability operator responsible for voltage schedules was across the hall from the transmission operators).

2. The lack of a shared electronic log (visible to all), as compared to FE's practice of separate hand-written logs.[43]

3. Lack of systematic procedures to brief incoming staff at shift change times.

4. Infrequent training of operators in emergency scenarios, identification and resolution of bad data, and the importance of sharing key information throughout the control room.

FE has specific written procedures and plans for dealing with resource deficiencies, voltage depressions, and overloads, and these include instructions to adjust generators and trip firm loads. After the loss of the Star-South Canton line, voltages were below limits, and there were severe line overloads. But FE did not follow any of these procedures on August 14, because FE did not know for most of that time that its system might need such treatment.

What training did the operators and reliability coordinators have for recognizing and responding to emergencies? FE relied upon on-the-job experience as training for its operators in handling the routine business of a normal day, but had never experienced a major disturbance and had no simulator training or formal preparation for recognizing and responding to emergencies. Although all affected FE and MISO operators were NERC-certified, NERC certification of operators addresses basic operational considerations but offers little insight into emergency operations issues. Neither group of operators had significant training, documentation, or actual experience for how to handle an emergency of this type and magnitude.

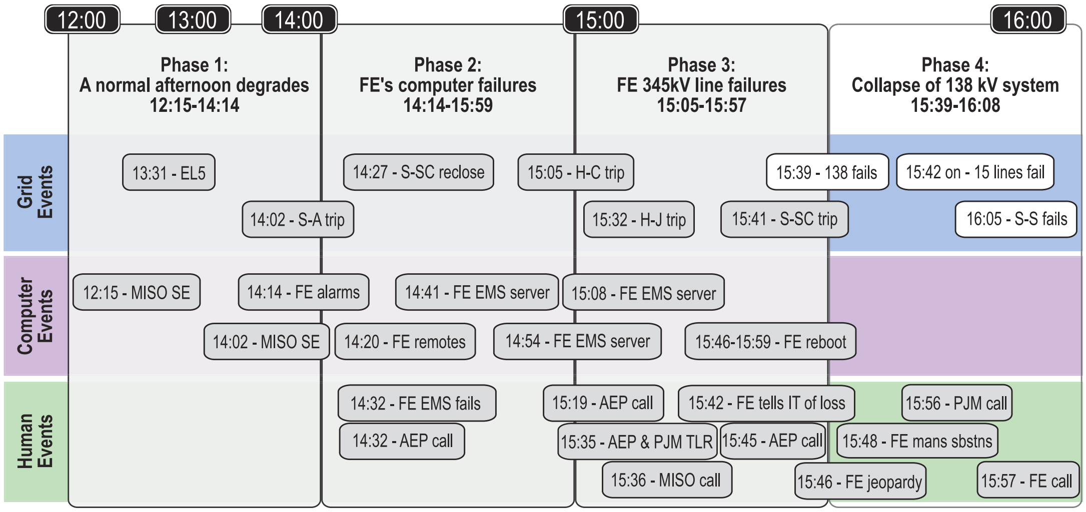
Recommendation
20, page 158

Cause 4
Inadequate RC Diagnostic Support

MISO was hindered because it lacked clear visibility, responsibility, authority, and ability to take the actions needed in this circumstance. MISO had interpretive and operational tools and a large amount of system data, but had a limited view of FE's system. In MISO's function as FE's reliability coordinator, its primary task was to initiate and implement TLRs, recognize and solve congestion problems in less dramatic reliability circumstances with longer solution time periods than those which existed on August 14, and provide assistance as requested.

Throughout August 14, most major elements of FE's EMS were working properly. The system was automatically transferring accurate real-time information about FE's system conditions to computers at AEP, MISO, and PJM. FE's operators did not believe the transmission line failures reported by AEP and MISO were real until 15:42 EDT, after FE conversations with the AEP and MISO control rooms and calls from FE IT staff to report the failure of their alarms. At that point in time, FE operators began to think that their system might be in jeopardy—but they did not act to restore any of the lost transmission lines, clearly alert their reliability coordinator or neighbors about their situation, or take other possible remedial measures (such as load- shedding) to stabilize their system.

Figure 5.13. Timeline Phase 4



Phase 4: 138-kV Transmission System Collapse in Northern Ohio: 15:39 to 16:08 EDT

Overview of This Phase

As each of FE's 345-kV lines in the Cleveland area tripped out, it increased loading and decreased voltage on the underlying 138-kV system serving Cleveland and Akron, pushing those lines into overload. Starting at 15:39 EDT, the first of an eventual sixteen 138-kV lines began to fail (Figure 5.13). Relay data indicate that each of these lines eventually ground faulted, which indicates that it sagged low enough to contact something below the line.

Figure 5.14 shows how actual voltages declined at key 138-kV buses as the 345- and 138-kV lines were lost. As these lines failed, the voltage drops caused a number of large industrial customers with voltage-sensitive equipment to go off-line automatically to protect their operations. As the 138-kV lines opened, they blacked out customers in Akron and the areas west and south of the city, ultimately dropping about 600 MW of load.

Key Phase 4 Events

Between 15:39 EDT and 15:58:47 EDT seven 138-kV lines tripped:

4A) 15:39:17 EDT: Pleasant Valley-West Akron 138-kV line tripped and reclosed at both ends after sagging into an underlying distribution line.

15:42:05 EDT: Pleasant Valley-West Akron 138-kV West line tripped and reclosed.

15:44:40 EDT: Pleasant Valley-West Akron 138-kV West line tripped and locked out.

4B) 15:42:49 EDT: Canton Central-Cloverdale 138-kV line tripped on fault and reclosed.

15:45:39 EDT: Canton Central-Cloverdale 138-kV line tripped on fault and locked out.

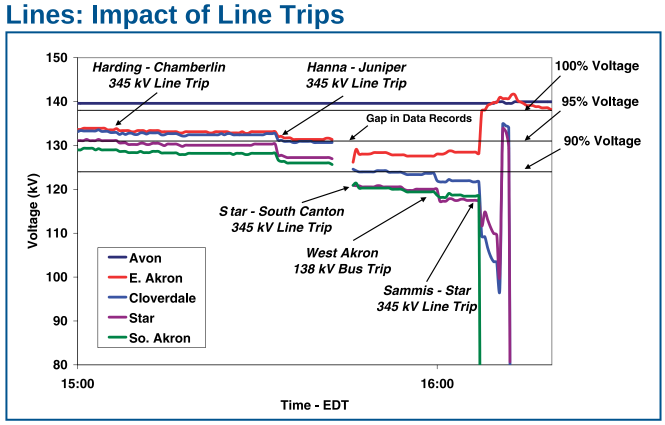
4C) 15:42:53 EDT: Cloverdale-Torrey 138-kV line tripped.

4D) 15:44:12 EDT: East Lima-New Liberty 138-kV line tripped from sagging into an underlying distribution line.

4E) 15:44:32 EDT: Babb-West Akron 138-kV line tripped on ground fault and locked out.

4F) 15:45:40 EDT: Canton Central 345/138 kV transformer tripped and locked out due to 138 kV circuit breaker operating multiple times,

Figure 5.14. Voltages on FirstEnergy's 138-kV Lines: Impact of Line Trips



which then opened the line to FE's Cloverdale station.

4G) 15:51:41 EDT: East Lima-N. Findlay 138-kV line tripped, likely due to sagging line, and reclosed at East Lima end only.

4H) 15:58:47 EDT: Chamberlin-West Akron 138-kV line tripped.

Note: 15:51:41 EDT: Fostoria Central-N. Findlay 138-kV line tripped and reclosed, but never locked out.

At 15:59:00 EDT, the loss of the West Akron bus tripped due to breaker failure, causing another five 138-kV lines to trip:

4I) 15:59:00 EDT: West Akron 138-kV bus tripped, and cleared bus section circuit breakers at West Akron 138 kV.

4J) 15:59:00 EDT: West Akron-Aetna 138-kV line opened.

4K) 15:59:00 EDT: Barberton 138-kV line opened at West Akron end only. West Akron-B18 138-kV tie breaker opened, affecting West Akron 138/12-kV transformers #3, 4 and 5 fed from Barberton.

4L) 15:59:00 EDT: West Akron-Granger-Stoney-Brunswick-West Medina opened.

4M) 15:59:00 EDT: West Akron-Pleasant Valley 138-kV East line (Q-22) opened.

4N) 15:59:00 EDT: West Akron-Rosemont-Pine-Wadsworth 138-kV line opened.

From 16:00 EDT to 16:08:59 EDT, four 138-kV lines tripped, and the Sammis-Star 345-kV line tripped due to high current and low voltage:

4O) 16:05:55 EDT: Dale-West Canton 138-kV line tripped due to sag into a tree, reclosed at West Canton only

4P) 16:05:57 EDT: Sammis-Star 345-kV line tripped

4Q) 16:06:02 EDT: Star-Urban 138-kV line tripped

4R) 16:06:09 EDT: Richland-Ridgeville-Napoleon-Stryker 138-kV line tripped on overload and locked out at all terminals

4S) 16:08:58 EDT: Ohio Central-Wooster 138-kV line tripped

Note: 16:08:55 EDT: East Wooster-South Canton 138-kV line tripped, but successful automatic reclosing restored this line.

4A-H) Pleasant Valley to Chamberlin-West Akron Line Outages

From 15:39 EDT to 15:58:47 EDT, seven 138-kV lines in northern Ohio tripped and locked out. At 15:45:41 EDT, Canton Central-Tidd 345-kV line tripped and reclosed at 15:46:29 EDT because Canton Central 345/138-kV CB "A1" operated multiple times, causing a low air pressure problem that inhibited circuit breaker tripping. This event forced the Canton Central 345/138-kV transformers to disconnect and remain out of service, further weakening the Canton-Akron area 138-kV transmission system. At 15:58:47 EDT the Chamberlin-West Akron 138-kV line tripped.

4I-N) West Akron Transformer Circuit Breaker Failure and Line Outages

At 15:59 EDT FE's West Akron 138-kV bus tripped due to a circuit breaker failure on West Akron transformer #1. This caused the five remaining 138-kV lines connected to the West Akron substation to open. The West Akron 138/12-kV transformers remained connected to the Barberton-West Akron 138-kV line, but power flow to West Akron 138/69-kV transformer #1 was interrupted.

4O-P) Dale-West Canton 138-kV and Sammis-Star 345-kV Lines Tripped

After the Cloverdale-Torrey line failed at 15:42 EDT, Dale-West Canton was the most heavily loaded line on FE's system. It held on, although heavily overloaded to 160 and 180% of normal ratings, until tripping at 16:05:55 EDT. The loss of this line had a significant effect on the area, and voltages dropped significantly. More power shifted back to the remaining 345-kV network, pushing Sammis-Star's loading above 120% of rating. Two seconds later, at 16:05:57 EDT, Sammis-Star tripped out. Unlike the previous three 345-kV lines, which tripped on short circuits to ground due to tree contacts, Sammis-Star tripped because its protective relays saw low apparent impedance (depressed voltage divided by abnormally high line current)—i.e., the relay reacted as if the high flow was due to a short circuit. Although three more 138-kV lines dropped quickly in Ohio following the Sammis-Star trip, loss of the Sammis-Star line marked the turning point at which system problems in northeast Ohio initiated a cascading blackout across the northeast United States and Ontario.

Losing the 138-kV Transmission Lines

The tripping of 138-kV transmission lines that began at 15:39 EDT occurred because the loss

Cause 1
Inadequate System Understanding

of the combination of the Harding-Chamberlin, Hanna-Juniper and Star-South Canton 345-kV lines overloaded the 138-kV system with electricity flowing north toward the Akron and Cleveland loads. Modeling indicates that the return of either the Hanna-Juniper or Chamberlin-Harding 345-kV lines would have diminished, but not alleviated, all of the 138-kV overloads. In theory, the return of both lines would have restored all the 138-kV lines to within their emergency ratings.

Cause 2
Inadequate Situational Awareness

However, all three 345-kV lines had already been compromised due to tree contacts so it is unlikely that FE would have successfully restored either line had they known it had tripped out, and since Star-South Canton had already tripped and reclosed three times it is also unlikely that an operator knowing this would have trusted it to operate securely under emergency conditions. While generation redispatch scenarios alone would not have solved the overload problem, modeling indicates that shedding load in the Cleveland and Akron areas may have reduced most line loadings to within emergency range and helped stabilize the system. However, the amount of load shedding required grew rapidly as FE's system unraveled.

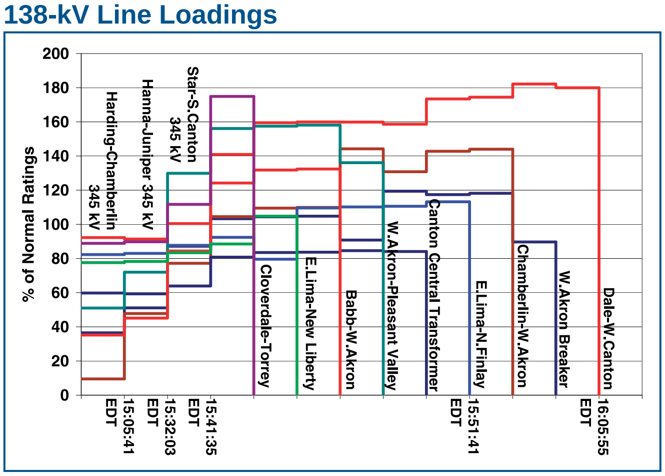
Preventing the Blackout with Load-Shedding

Cause 1
Inadequate System Understanding

The investigation team examined whether load shedding before the loss of the Sammis-Star 345-kV line at 16:05:57 EDT could have prevented this line loss. The team found that 1,500 MW of load would have had to be dropped within the Cleveland-Akron area to restore voltage at the Star bus from 90.8% (at 120% of normal and emergency ampere rating) up to 95.9% (at 101% of normal and emergency ampere rating).[44] The P-V and V-Q analysis reviewed in Chapter 4 indicated that 95% is the minimum operating voltage appropriate for 345-kV buses in the Cleveland-Akron area. The investigation team concluded that since the Sammis-Star 345 kV outage was the critical event leading to widespread cascading in Ohio and beyond, if manual or automatic load-shedding of 1,500 MW had occurred within the Cleveland-Akron area before that outage, the blackout could have been averted.

Recommendations
8, page 147; 21, page 158; 23, page 160

Figure 5.15. Simulated Effect of Prior Outages on 138-kV Line Loadings



Loss of the Sammis-Star 345-kV Line

Figure 5.15, derived from investigation team modeling, shows how the power flows shifted across FE's 345- and key 138-kV northeast Ohio lines as the line failures progressed. All lines were loaded within normal limits after the Harding-Chamberlin lock-out, but after the Hanna-Juniper trip at 15:32 EDT, the Star-South Canton 345-kV line and three 138-kV lines jumped above normal loadings. After Star-South Canton locked out at 15:41 EDT within its emergency rating, five 138-kV and the Sammis-Star 345-kV lines were overloaded. From that point, as the graph shows, each subsequent line loss increased loadings on other lines, some loading to well over 150% of normal ratings before they failed. The Sammis-Star 345-kV line stayed in service until it tripped at 16:05:57 EDT.

FirstEnergy had no automatic load-shedding schemes in place, and did not attempt to begin manual load-shedding. As Chapters 4 and 5 have established, once Sammis-Star tripped, the possibility of averting the coming cascade by shedding load ended. Within 6 minutes of these overloads, extremely low voltages, big power swings and accelerated line tripping would cause separations and blackout within the Eastern Interconnection.

Recommendation
21, page 158

Endnotes

1 Investigation team field visit to FE 10/8/2003: Steve Morgan.

2 Investigation team field visit to FE, September 3, 2003, Hough interview: "When asked whether the voltages seemed unusual, he said that some sagging would be expected on a hot day, but on August 14th the voltages did seem unusually low." Spidle interview: "The voltages for the day were not particularly bad."

[3] Manual of Operations, valid as of March 3, 2003, Process flowcharts: Voltage Control and Reactive Support – Plant and System Voltage Monitoring Under Normal Conditions.

[4] 14:13:18. Channel 16 - Sammis 1. 13:15:49 / Channel 16 – West Lorain (FE Reliability Operator (RO) says, "Thanks. We're starting to sag all over the system.") / 13:16:44. Channel 16 – Eastlake (talked to two operators) (RO says, "We got a way bigger load than we thought we would have." And "…So we're starting to sag all over the system.") / 13:20:22. Channel 16 – RO to "Berger" / 13:22:07. Channel 16 – "control room" RO says, "We're sagging all over the system. I need some help." / 13:23:24. Channel 16 – "Control room, Tom" / 13:24:38. Channel 16 – "Unit 9" / 13:26:04. Channel 16 – "Dave" / 13:28:40. Channel 16 "Troy Control." Also general note in RO Dispatch Log.

[5] Example at 13:33:40, Channel 3, FE transcripts.

[6] Investigation team field visit to MISO, Walsh and Seidu interviews.

[7] FE had and ran a state estimator every 30 minutes. This served as a base from which to perform contingency analyses. FE's contingency analysis tool used SCADA and EMS inputs to identify any potential overloads that could result from various line or equipment outages. FE indicated that it has experienced problems with the automatic contingency analysis operation since the system was installed in 1995. As a result, FE operators or engineers ran contingency analysis manually rather than automatically, and were expected to do so when there were questions about the state of the system. Investigation team interviews of FE personnel indicate that the contingency analysis model was likely running but not consulted at any point in the afternoon of August 14.

[8] After the Stuart-Atlanta line tripped, Dayton Power & Light did not immediately provide an update of a change in equipment availability using a standard form that posts the status change in the SDX (System Data Exchange, the NERC database which maintains real-time information on grid equipment status), which relays that notice to reliability coordinators and control areas. After its state estimator failed to solve properly, MISO checked the SDX to make sure that they had properly identified all available equipment and outages, but found no posting there regarding Stuart-Atlanta's outage.

[9] Investigation team field visit, interviews with FE personnel on October 8-9, 2003.

[10] DOE Site Visit to First Energy, September 3, 2003, Interview with David M. Elliott.

[11] FE Report, "Investigation of FirstEnergy's Energy Management System Status on August 14, 2003," Bullet 1, Section 4.2.11.

[12] Investigation team interviews with FE, October 8-9, 2003.

[13] Investigation team field visit to FE, October 8-9, 2003: team was advised that FE had discovered this effect during post-event investigation and testing of the EMS. FE's report "Investigation of FirstEnergy's Energy Management System Status on August 14, 2003" also indicates that this finding was "verified using the strip charts from 8-14-03" (page 23), not that the investigation of this item was instigated by operator reports of such a failure.

[14] There is a conversation between a Phil and a Tom that speaks of "flatlining" 15:01:33. Channel 15. There is no mention of AGC or generation control in the DOE Site Visit interviews with the reliability coordinator.

[15] FE Report, "Investigation of FirstEnergy's Energy Management System Status on August 14, 2003."

[16] Investigation team field visit to FE, October 8-9, 2003, Sanicky Interview: "From his experience, it is not unusual for alarms to fail. Often times, they may be slow to update or they may die completely. From his experience as a real-time operator, the fact that the alarms failed did not surprise him." Also from same document, Mike McDonald interview, "FE has previously had [servers] down at the same time. The big issue for them was that they were not receiving new alarms."

[17] A "cold" reboot of the XA21 system is one in which all nodes (computers, consoles, etc.) of the system are shut down and then restarted. Alternatively, a given XA21 node can be "warm" rebooted wherein only that node is shut down and restarted, or restarted from a shutdown state. A cold reboot will take significantly longer to perform than a warm one. Also during a cold reboot much more of the system is unavailable for use by the control room operators for visibility or control over the power system. Warm reboots are not uncommon, whereas cold reboots are rare. All reboots undertaken by FE's IT EMSS support personnel on August 14 were warm reboots.

[18] The cold reboot was done in the early morning of 15 August and corrected the alarm problem as hoped.

[19] Example at 14:19, Channel l4, FE transcripts.

[20] Example at 14:25, Channel 8, FE transcripts.

[21] Example at 14:32, Channel 15, FE transcripts.

[22] "Interim Report, Utility Vegetation Management," U.S.-Canada Joint Outage Investigation Task Force, Vegetation Management Program Review, October 2003, page 7.

[23] Investigation team transcript, meeting on September 9, 2003, comments by Mr. Steve Morgan, Vice President Electric Operations:

Mr. Morgan: The sustained outage history for these lines, 2001, 2002, 2003, up until the event, Chamberlin-Harding had zero operations for those two-and-a-half years. And Hanna-Juniper had six operations in 2001, ranging from four minutes to maximum of 34 minutes. Two were unknown, one was lightning, one was a relay failure, and two were really relay scheme mis-operations. They're category other. And typically, that—I don't know what this is particular to operations, that typically occurs when there is a mis-operation.

Star-South Canton had no operations in that same period of time, two-and-a-half years. No sustained outages. And Sammis-Star, the line we haven't talked about, also no sustained outages during that two-and-a-half year period. So is it normal? No. But 345 lines do operate, so it's not unknown.

[24] "Utility Vegetation Management Final Report," CN Utility Consulting, March 2004, page 32.

[25] "FE MISO Findings," page 11.

[26] FE was conducting right-of-way vegetation maintenance on a 5-year cycle, and the tree crew at Hanna-Juniper was three spans away, clearing vegetation near the line, when the contact occurred on August 14. Investigation team 9/9/03 meeting transcript, and investigation field team discussion with the tree-trimming crew foreman.

[27] Based on "FE MISO Findings" document, page 11.

[28] "Interim Report, Utility Vegetation Management," US-Canada Joint Outage Task Force, Vegetation Management Program Review, October 2003, page 6.

[29] Investigation team September 9, 2003 meeting transcripts, Mr. Steve Morgan, First Energy Vice President, Electric System Operations:

Mr. Benjamin: Steve, just to make sure that I'm understanding it correctly, you had indicated that once after Hanna-Juniper relayed out, there wasn't really a problem with voltage on the system until Star-S. Canton operated. But were the system operators aware that when Hanna-Juniper was out, that if Star-S. Canton did trip, they would be outside of operating limits?

Mr. Morgan: I think the answer to that question would have required a contingency analysis to be done probably on demand for that operation. It doesn't appear to me that a contingency analysis, and certainly not a demand contingency analysis, could have been run in that period of time. Other than experience, I don't know that they would have been able to answer that question. And what I know of the record right now is that it doesn't appear that they ran contingency analysis on demand.

Mr. Benjamin: Could they have done that?

Mr. Morgan: Yeah, presumably they could have.

Mr. Benjamin: You have all the tools to do that?

Mr. Morgan: They have all the tools and all the information is there. And if the State Estimator is successful in solving, and all the data is updated, yeah, they could have. I would say in addition to those tools, they also have access to the planning load flow model that can actually run the same—full load of the model if they want to.

[30] Example synchronized at 14:32 (from 13:32) #18 041 TDC-E2 283.wav, AEP transcripts.

[31] Example synchronized at 14:19 #2 020 TDC-E1 266.wav, AEP transcripts.

[32] Example at 15:36 Channel 8, FE transcripts.

[33] Example at 15:41:30 Channel 3, FE transcripts.

[34] Example synchronized at 15:36 (from 14:43) Channel 20, MISO transcripts.

[35] Example at 15:42:49, Channel 8, FE transcripts.

[36] Example at 15:46:00, Channel 8 FE transcripts.

[37] Example at 15:45:18, Channel 4, FE transcripts.

[38] Example at 15:46:00, Channel 8 FE transcripts.

[39] Example at 15:50:15, Channel 12 FE transcripts.

[40] Example synchronized at 15:48 (from 14:55), channel 22, MISO transcripts.

[41] Example at 15:56:00, Channel 31, FE transcripts.

[42] FE Transcripts 15:45:18 on Channel 4 and 15:56:49 on Channel 31.

[43] The operator logs from FE's Ohio control center indicate that the west desk operator knew of the alarm system failure at 14:14, but that the east desk operator first knew of this development at 15:45. These entries may have been entered after the times noted, however.

[44] The investigation team determined that FE was using a different set of line ratings for Sammis-Star than those being used in the MISO and PJM reliability coordinator calculations or by its neighbor AEP. Specifically, FE was operating Sammis-Star assuming that the 345-kV line was rated for summer normal use at 1,310 MVA, with a summer emergency limit rating of 1,310 MVA. In contrast, MISO, PJM and AEP were using a more conservative rating of 950 MVA normal and 1,076 MVA emergency for this line. The facility owner (in this case FE) is the entity which provides the line rating; when and why the ratings were changed and not communicated to all concerned parties has not been determined.