NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
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Technical Analysis of the August 14, 2003, Blackout:
What Happened, Why, and What Did We Learn?

Report to the NERC Board of Trustees by the NERC Steering Group

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Acknowledgements

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NERC acknowledges the strong leadership of the Steering Group, which guided the investigation on behalf of NERC. The Steering Group members are:

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David Hilt, NERC Vice President-Compliance, directed the NERC investigation. He was assisted by Gerry Cauley, Director-Standards.

The NERC investigation team leaders are worthy of special recognition for their extraordinary efforts in managing assigned portions of the investigation. It was their expertise, objectivity, and hard work that made the investigation a success. They provided the analytical insights into what happened on August 14 and why, and developed much of the material included in this final report. The team leaders making significant contributions to the final report are:

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More than 100 additional volunteers and the staffs of NERC and the regional reliability councils participated in the investigation. To all who helped, both named and unnamed, thank you!

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I. Introduction

On August 14, 2003, just after 4 p.m. Eastern Daylight Time (EDT),[1] the North American power grid experienced its largest blackout ever. The blackout affected an estimated 50 million people and more than 70,000 megawatts (MW) of electrical load in parts of Ohio, Michigan, New York, Pennsylvania, New Jersey, Connecticut, Massachusetts, Vermont, and the Canadian provinces of Ontario and Québec. Although power was successfully restored to most customers within hours, some areas in the United States did not have power for two days and parts of Ontario experienced rotating blackouts for up to two weeks.

This report looks at the conditions on the bulk electric system that existed prior to and during the blackout, and explains how the blackout occurred. The report concludes with a series of recommendations for actions that can and should be taken by the electric industry to prevent or minimize the chance of such an outage occurring in the future.

A. NERC Investigation

1. Scope of Investigation

Historically, blackouts and other significant electric system events have been investigated by the affected regional reliability councils. The NERC Disturbance Analysis Working Group would then review the regional reports and prepare its own evaluation of the broader lessons learned. The August 14 blackout was unique with regard to its magnitude and the fact that it affected three NERC regions. The scope and depth of NERC's investigation into a blackout of this magnitude was unprecedented.

Immediately following the blackout, NERC assembled a team of technical experts from across the United States and Canada to investigate exactly what happened, why it happened, and what could be done to minimize the chance of future outages. To lead this effort, NERC established a steering group of leading experts from organizations that were not directly affected by the cascading grid failure.

The scope of NERC's investigation was to determine the causes of the blackout, how to reduce the likelihood of future cascading blackouts, and how to minimize the impacts of any that do occur. NERC focused its analysis on factual and technical issues including power system operations, planning, design, protection and control, and maintenance. Because it is the responsibility of all power system operating entities to operate the electric system reliably at all times, irrespective of regulatory, economic, or market factors, the NERC investigation did not address regulatory, economic, market structure, or policy issues.

2. Support for U.S.-Canada Power System Outage Task Force

NERC's technical investigation became a critical component of the U.S.-Canada Power System Outage Task Force, a bi-national group formed to examine all aspects of the August 14 outage. The Task Force formed three working groups to investigate the electric power system, nuclear power plant, and security aspects of the blackout. The electric system working group was led by representatives from the U.S. Department of Energy, the U.S. Federal Energy Regulatory Commission, and Natural Resources Canada.

The NERC investigation provided support to the electric system working group, analyzing enormous volumes of data to determine a precise sequence of events leading to and during the cascade. The NERC

[1] All times referenced in this report have been converted to Eastern Daylight Time.

teams met regularly with representatives of the Task Force to determine why the blackout occurred and why it extended as far as it did.

In its November 19 interim report, the Task Force concluded, and NERC concurred, that the initiating causes of the blackout were 1) that FirstEnergy (FE) lost functionality of its critical monitoring tools and as a result lacked situational awareness of degraded conditions on its transmission system, 2) that FE did not adequately manage tree growth in its transmission rights-of-way, 3) that the Midwest Independent System Operator (MISO) reliability coordinator did not provide adequate diagnostic support, and 4) that coordination between the MISO and PJM reliability coordinators was ineffective. The report cited several violations of NERC reliability standards as contributing to the blackout.

After the interim report was issued, NERC continued to support the electric system working group. NERC also began to develop its own technical report and a set of recommendations to address issues identified in the investigation.

3. Investigation Organization

Before the electric system had been fully restored, NERC began to organize its investigation. NERC appointed a steering group of industry leaders with extensive executive experience, power system expertise, and objectivity. This group was asked to formulate the investigation plan and scope, and to oversee NERC's blackout investigation.

NERC's initial efforts focused on collecting system data to establish a precise sequence of events leading up to the blackout. In the initial stage of the investigation, investigators began to build a sequence of events from information that was then available from NERC regions and from reliability coordinators. To complete such a large-scale investigation, however, it quickly became apparent that additional resources were needed. The investigation was augmented with individuals from the affected areas that had knowledge of their system design, configuration, protection, and operations. Having this first-hand expertise was critical in developing the initial sequence of events. These experts were added to the investigation teams and each team was assigned to build a sequence of events for a specific geographic area. As the sequence of events became more detailed, a database was created to facilitate management of the data and to reconcile conflicting time stamps on the thousands of events that occurred in the time leading up to and during the power system failure.

The NERC Steering Group organized investigators into teams to analyze discrete events requiring specific areas of expertise, as shown in Figure I.1. To fill these teams, NERC called on industry volunteers. The number and quality of experts who answered the call was extraordinary. Many of these volunteers relocated temporarily to Princeton, New Jersey, to allow for close collaboration during the investigation. The teams dedicated long hours — often seven days per week — over several months to analyze what happened and why. The investigators operated with complete autonomy to investigate all possible causes of the blackout. The investigation methods were systematic — investigators "looked under every rock" and methodically proved or disproved each theory put forth as to why and how the blackout occurred.

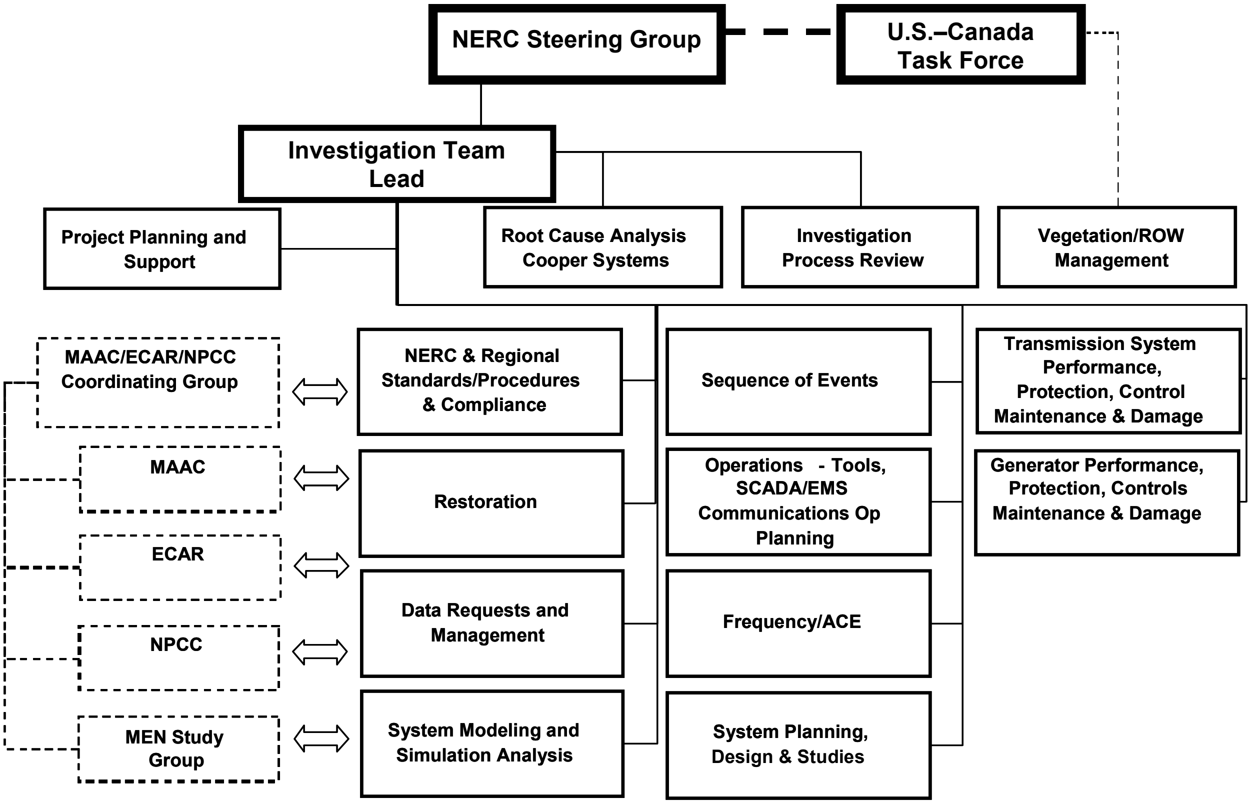


Figure I.1 — NERC Blackout Investigation Organization

4. Investigation Process

Under the guidance of the Steering Group, NERC developed a formal investigation plan. The investigation plan assigned work scopes, deliverables, and milestones for each investigation team. The major elements of the investigation process are summarized here:

- In the first days after the blackout, NERC and the reliability coordinators conferred by hotline calls to assess the status of system restoration, the continuing capacity shortage and rotating blackouts, and initial information on what had happened.
- On August 17, NERC notified all reliability coordinators and control areas in the blackout area to retain state estimator, relay, and fault recorder data from 08:00 to 17:00 on August 14. A subsequent request added event logs, one-line diagrams, and system maps to the list. On August 22, NERC issued a more substantive data request for the hours of 08:00 to 22:00 on August 14. Additional data requests were made as the investigation progressed. The response to the data requests was excellent; many entities submitted more information related to the blackout than was requested. To manage the enormous volume of data, NERC installed additional computers and a relational database, and assigned a team to catalog and manage the data.
- As part of the U.S.-Canada Power System Outage Task Force investigation and in cooperation with NERC, the U.S. Department of Energy conducted onsite interviews with operators, engineers, computer staff, supervisors, and others at all of the affected reliability coordinator and control area operating centers.
- The analysis portion of the investigation began with the development of a sequence of events. The initial focus was on the critical events leading up to the power system cascade. The task was painstakingly arduous due to the large volume of event data and the limited amount of

information that was precisely synchronized to a national time standard. Assembling the timeline to the level of accuracy needed for the remaining areas of investigation was analogous to completing a jigsaw puzzle with thousands of unique interlocking pieces. The initial sequence of events was published on September 12, 2003.

- NERC established teams to analyze different aspects of the blackout. Each team was assigned a scope and the necessary experts to complete its mission. The teams interacted frequently with investigation leaders and with the co-chairs of the electric system working group.

- A cornerstone of the investigation was a root cause analysis sponsored by the U.S. Department of Energy and facilitated by a contractor with expertise in that area. This systematic approach served to focus the investigation teams on proving the causes of the blackout based on verified facts. The work of these investigation teams was based on a) gathering data; b) verifying facts through multiple, independent sources; c) performing analysis and simulations with the data; and d) conducting an exhaustive forensic analysis of the causes of the blackout.

- NERC assisted the U.S.-Canada Power System Outage Task Force in conducting a series of information-gathering meetings on August 22, September 8–9, and October 1–3. These meetings were open only to invited entities; each meeting was recorded, and a transcription prepared for later use by investigators. The first meeting focused on assessing what was known about the blackout sequence and its causes, and identifying additional information requirements. The second meeting focused on technical issues framed around a set of questions directed to each entity operating in the blackout area. The third meeting focused on verifying detailed information to support the root cause analysis. Participation was narrowed to include only the investigators and representatives of the FirstEnergy and AEP control areas, and the Midwest Independent Transmission System Operator (MISO) and PJM reliability coordinators.
- On October 15, 2003, NERC issued a letter to all reliability coordinators and system operating entities that required them to address some of the key issues arising from the investigation.
- On November 19, 2003, the U.S.-Canada Power System Outage Task Force issued its interim report on the events and causes of the August 14 blackout. The report was developed in collaboration with the NERC investigation and NERC concurred with the report's findings.
- The second phase of the blackout investigation began after the interim report was released. For NERC, the second phase focused on two areas. First, NERC continued to analyze why the cascade started and spread as far as it did. The results of this analysis were incorporated into this report and also provided to the U.S.-Canada Power System Outage Task Force for inclusion in its final report, which was issued on April 5, 2004. NERC also began, independently of the Task Force, to develop an initial set of recommendations to minimize the risk and mitigate the impacts of possible future cascading failures. These recommendations were approved by the NERC Board of Trustees on February 10, 2004.

5. Coordination with NERC Regions

The NERC regions and the regional transmission organizations (RTOs) within these regions played an important role in the NERC investigation; these entities also conducted their own analyses of the events that occurred within their regions. The regions provided a means to identify all facility owners and to collect the necessary data. Regular conference calls were held to coordinate the NERC and regional investigations and share results.

The NERC regions provided expert resources for system modeling and simulation and other aspects of the analysis. The investigation relied on the multi-regional MAAC-ECAR-NPCC Operations Studies

Working Group, which had developed summer loading models of the systems affected by the blackout. Other groups, such as the SS-38 Task Force (system dynamics data) and Major System Disturbance Task Force, provided valuable assistance to the investigation.

The restoration phase of the blackout was successful, and NERC has deferred the bulk of the analysis of system restoration efforts to the regions, RTOs, and operating entities. Evaluation of the restoration is a significant effort that requires analyzing the effectiveness of thousands of actions against local and regional restoration plans. The results of this analysis will be consolidated by NERC and reported at a future date.

6. Ongoing Dynamic Investigation

The electrical dynamics of the blackout warrant unprecedented detailed technical analysis. The MAAC-ECAR-NPCC Major System Disturbance Task Force continues to analyze the dynamic swings in voltage, power flows, and other events captured by high-speed disturbance recorders. The results of that work will be published as they become available.

B. Report Overview

The report begins by telling a detailed story of the blackout, outlining what happened, and why. This portion of the report is organized into three sections: Section II describes system conditions on August 14 prior to the blackout, Section III describes events in northeastern Ohio that triggered the start of an uncontrolled cascade of the power system, and Section IV describes the ensuing cascade. The report concludes in Section V with a summary of the causes of the blackout, contributing factors, and other deficiencies. This section also provides a set of NERC recommendations. The majority of these recommendations were approved on February 10, 2004; however, several new recommendations have been added. Supplemental reports developed by investigation teams are under development and will be available in phase II of this report.

A report on vegetation management issues developed by the U.S.-Canada Power System Outage Task Force is an additional reference that complements this report.

C. Key Entities Affected by the August 14 Blackout

1. Electric Systems Affected by the Blackout

The August 14 blackout affected the northeastern portion of the Eastern Interconnection, covering portions of three NERC regions. The blackout affected electric systems in northern Ohio, eastern Michigan, northern Pennsylvania and New Jersey, much of New York and Ontario. To a lesser extent, Massachusetts, Connecticut, Vermont, and Québec were impacted. The areas affected by the August 14 blackout are shown in Figure I.2.

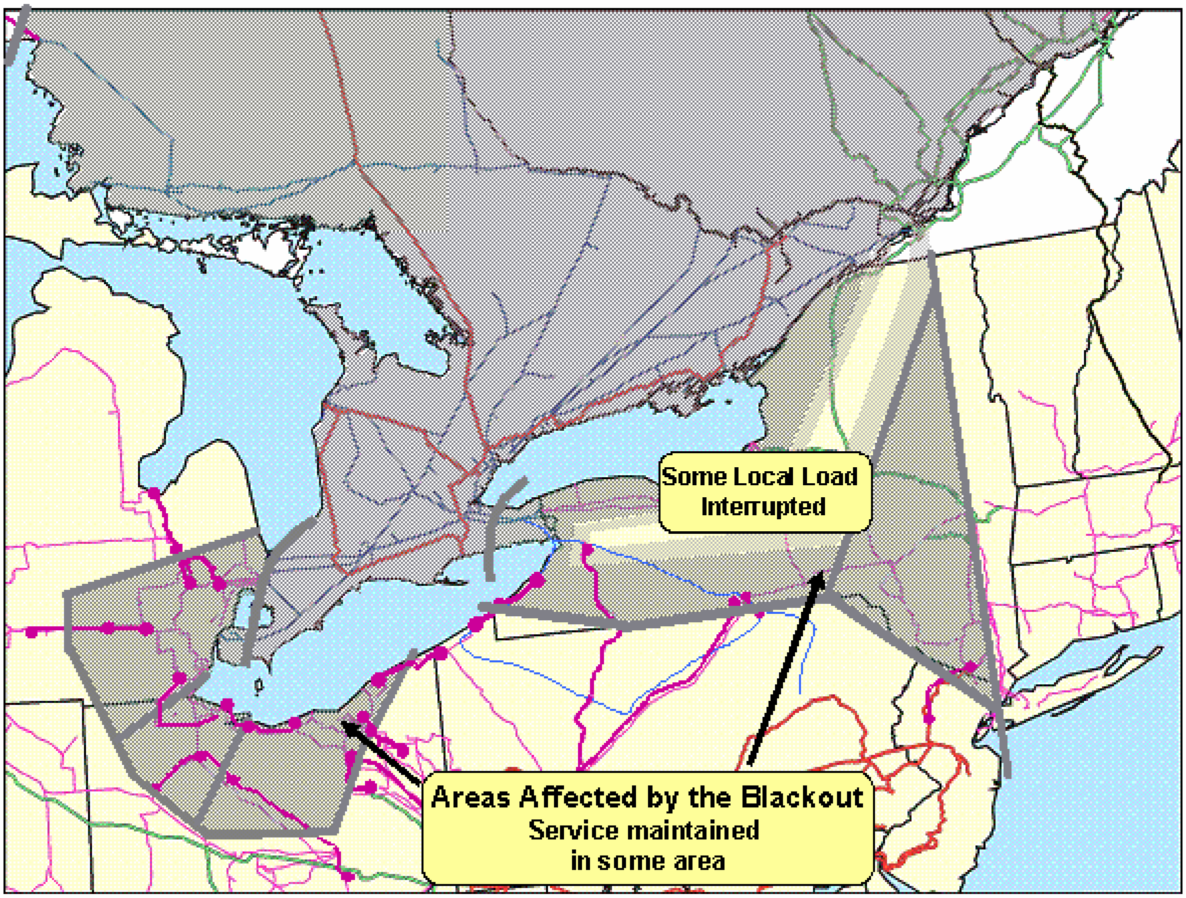


Figure I.2 — Area Affected by the Blackout

The power system in Ontario is operated by the Independent System Operator (IMO). The New York system is operated by the New York Independent System Operator (NYISO). The mid-Atlantic area, including the northern Pennsylvania and northern New Jersey areas affected by the blackout, is operated by the PJM Interconnection, LLC (PJM). Each of these entities operates an electricity market in their respective area and is responsible for reliability of the bulk electric system in that area. Each is designated as both the system operator and the reliability coordinator for their respective area.

In the Midwest, several dozen utilities operate their own systems in their franchise territory. Reliability oversight in this region is provided by two reliability coordinators, the Midwest Independent Transmission System Operator (MISO) and PJM.

New England, which is operated by the New England Independent System Operator (ISO-NE), was in the portion of the Eastern Interconnection that became separated, but was able to stabilize its generation and load with minimal loss, except for the southwest portion of Connecticut, which blacked out with New York City. Nova Scotia and Newfoundland were also not impacted severely. Hydro-Québec operates the electric system in Québec and was mostly unaffected by the blackout because this system is operated asynchronously from the rest of the interconnection.

Several of the key players involved in the blackout are described in more detail below.

2. FirstEnergy Corporation

FirstEnergy Corporation (FE) is the fifth largest electric utility in the United States. FE serves 4.4 million electric customers in a 36,100 square mile service territory covering parts of Ohio, Pennsylvania, and New Jersey. FE operates 11,502 miles of transmission lines, and has 84 ties with 13 other electric systems.

FE comprises seven operating companies (Figure I.3). Four of these companies, Ohio Edison, Toledo Edison, The Illuminating Company, and Penn Power, operate in the ECAR region; MISO serves as their reliability coordinator. These four companies now operate as one integrated control area managed by FE. The remaining three FE companies, Penelec, Met-Ed, and Jersey Central Power & Light, are in the MAAC region and PJM is their reliability coordinator. This report addresses the FE operations in northern Ohio, within ECAR and the MISO reliability coordinator footprint.

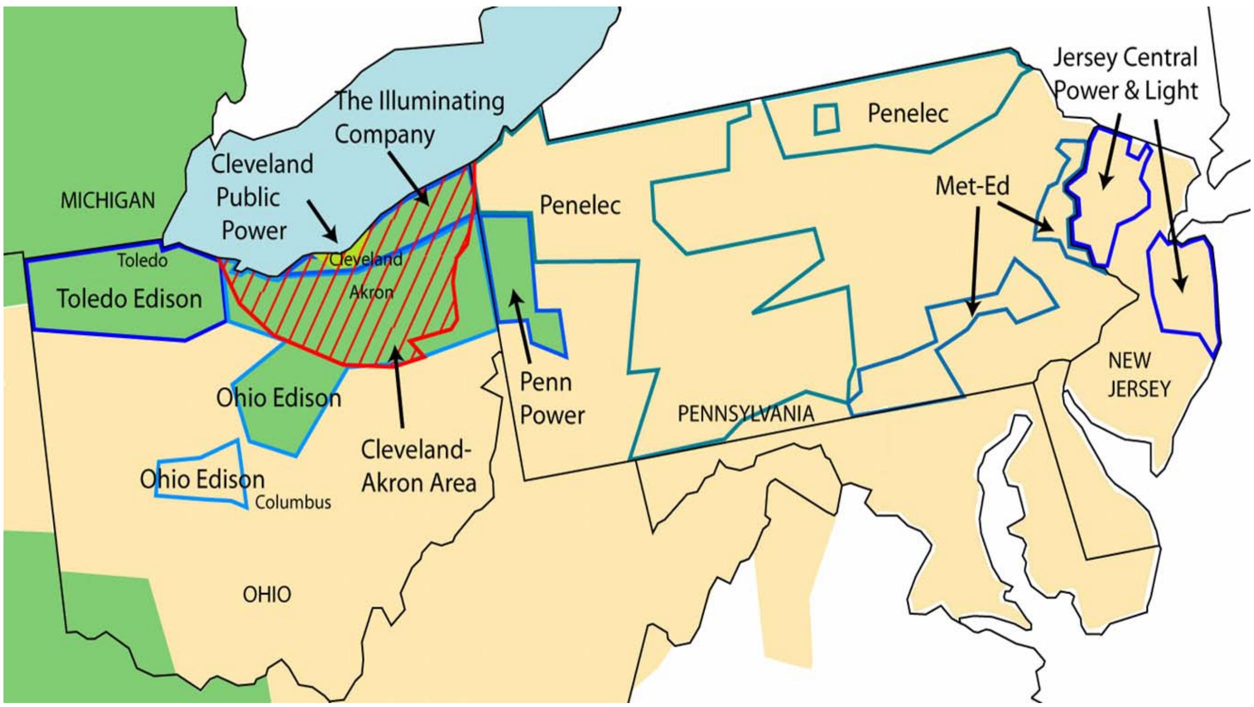


Figure I.3 — FE Operating Areas

FE operates several control centers in Ohio that perform different functions. The first is the unregulated Generation Management System (GMS), which is located in a separate facility from the transmission system operations center. The GMS handles the unregulated generation portion of the business, including Automatic Generation Control (AGC) for the FE units, managing wholesale transactions, determining fuel options for their generators, and managing ancillary services. On August 14, the GMS control center was responsible for calling on automatic reserve sharing to replace the 612 MW lost when the Eastlake Unit 5 tripped at 13:31.

The second FE control center houses the Energy Management System (EMS). The EMS control center is charged with monitoring the operation and reliability of the FE control area and is managed by a director of transmission operation services. Two main groups report to the director. The first group is responsible for real-time operations and the second is responsible for transmission operations planning support. The operations planning group has several dispatchers who perform day-ahead studies in a room across the hall from the control room.

The real-time operations group is divided into two areas: control area operators and transmission operators. Each area has two positions that are staffed 24 hours a day. A supervisor with responsibility for both areas is always present. The supervisors work 8-hour shifts (7:00–15:00, 15:00–21:00, and 21:00–7:00), while the other operators work 12-hour shifts (6:00–18:00 and 18:00–6:00). The transmission operators are in the main control room, the control area operators are in a separate room.

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

In addition to the EMS control center, FE maintains several regional control centers. These satellite operating centers are responsible for monitoring the 34.5-kV and 23-kV distribution systems. These remote consoles are part of the GE/Harris EMS system discussed later in this report, and represent some of the remote console failures that occurred.

3. MISO

The Midwest Independent Transmission System Operator (MISO) is the reliability coordinator for a region that covers more than one million square miles, stretching from Manitoba, Canada, in the north to Kentucky in the south; from Montana in the west to western Pennsylvania in the east. Reliability coordination is provided by two offices, one in Minnesota, and the other at the MISO headquarters in Carmel, Indiana. MISO provides reliability coordination for 35 control areas, most of which are members of MISO.

MISO became the reliability coordinator for FirstEnergy on February 1, 2003, when the ECAR-MET reliability coordinator office operated by AEP became part of PJM. FirstEnergy became a full member of MISO on October 1, 2003, six weeks after the blackout.

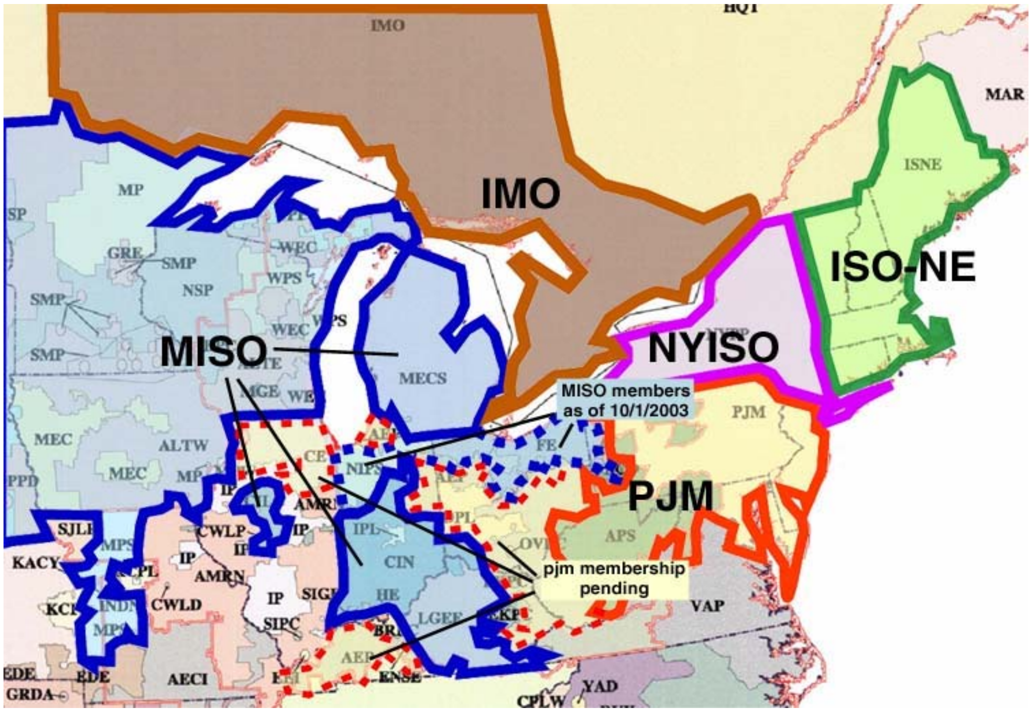


Figure I.4 — Midwest Reliability Coordinators

4. AEP

American Electric Power (AEP), based in Columbus, Ohio, owns and operates more than 80 generating stations with more than 42,000 MW of generating capacity in the United States and international markets. AEP is one of the largest electric utilities in the United States, with more than five million customers linked to AEP's 11-state electricity transmission and distribution grid. AEP's 197,500 square mile service territory includes portions of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. AEP operates approximately 39,000 miles of electric transmission lines. AEP operates the control area in Ohio just south of the FE system.

AEP system operations functions are divided into two groups: transmission and control area operations. AEP transmission dispatchers issue clearances, perform restoration after an outage, and conduct other operations such as tap changing and capacitor bank switching. They monitor all system parameters, including voltage. AEP control area operators monitor ACE, maintain contact with the PJM reliability coordinator, implement transaction schedules, watch conditions on critical flowgates, implement the NERC Transmission Loading Relief (TLR) process, and direct generator voltage schedules. AEP maintains and operates an energy management system complete with a state estimator and on-line contingency analysis that runs every five minutes.

5. PJM Interconnection, LLC

The PJM Interconnection, LLC (PJM) is AEP's reliability coordinator. PJM's reliability coordination activity is centered in its Valley Forge, Pennsylvania, headquarters with two operating centers, one in Valley Forge and one in Greensburg, Pennsylvania. There are two open video/audio live links between the west control center in Greensburg and the east control center in Valley Forge that provide for connectivity and presence between the two control centers. In training, operators are moved between all of the desks in Valley Forge and Greensburg.

PJM is also an independent system operator. PJM recently expanded its footprint to include control areas and transmission operators within MAIN and ECAR into an area it has designated as PJM-West. In PJM-East, the original PJM power pool, PJM is both the control area operator and reliability coordinator for ten utilities whose transmission systems span the Mid-Atlantic region of New Jersey, most of Pennsylvania, Delaware, Maryland, West Virginia, Ohio, Virginia, and the District of Columbia. At the time of the blackout, the PJM-West facility was the reliability coordinator desk for several control areas (Commonwealth Edison-Exelon, AEP, Duquesne Light, Dayton Power and Light, and Ohio Valley Electric Cooperative) and four generation-only control areas (Duke Energy's Washington County (Ohio) facility, Duke's Lawrence County/Hanging Rock (Ohio) facility, Allegheny Energy's Buchanan (West Virginia) facility, and Allegheny Energy's Lincoln Energy Center (Illinois) facility.

6. ECAR

The East Central Area Reliability Coordination Agreement (ECAR) is one of the ten NERC regional reliability councils. ECAR was established in 1967 as the forum to address matters related to the reliability of interconnected bulk electric systems in the east central part of the United States. ECAR members maintain reliability by coordinating the planning and operation of the members' generation and transmission facilities. ECAR membership includes 29 major electricity suppliers located in nine states serving more than 36 million people. The FE and AEP systems of interest in Ohio are located within ECAR.

ECAR is responsible for monitoring its members for compliance with NERC operating policies and planning standards. ECAR is also responsible for coordinating system studies conducted to assess the adequacy and reliability of its member systems.

II. Conditions Prior to the Start of the Blackout Sequence

The electricity industry has developed and codified a set of mutually reinforcing reliability standards and practices to ensure that system operators are prepared to deal with unexpected system events. The basic assumption underlying these standards and practices is that power system elements will fail or become unavailable in unpredictable ways. The basic principle of reliability management is that "operators must operate to maintain the security of the system they have available."

Sound reliability management is geared toward ensuring the system will continue to operate safely following the unexpected loss of any element, such as a major generating or transmission facility. Therefore, it is important to emphasize that establishing whether conditions on the system were normal or unusual prior to and on August 14 would not in either case alleviate the responsibilities and actions expected of the power system operators, who are charged with ensuring reliability.

In terms of day-ahead planning, system operators must analyze the system and adjust the planned outages of generators and transmission lines or scheduled electricity transactions, so that if a facility was lost unexpectedly, the system operators would still be able to operate the remaining system within safe limits. In terms of real-time operations, this means that the system must be operated at all times to be able to withstand the loss of any single facility and still remain within thermal, voltage, and stability limits. If a facility is lost unexpectedly, system operators must take necessary actions to ensure that the remaining system is able to withstand the loss of yet another key element and still operate within safe limits. Actions system operators may take include adjusting the outputs of generators, curtailing electricity transactions, curtailing interruptible load, and shedding firm customer load to reduce electricity demand to a level that matches what the system is able to deliver safely. These practices have been designed to maintain a functional and reliable grid, regardless of whether actual operating conditions are normal.

A. Summary of System Conditions on August 14, 2003

This section reviews the status of the northeastern portion of the Eastern Interconnection prior to 15:05 on August 14. Analysis was conducted to determine whether system conditions at that time were in some way unusual and might have contributed to the initiation of the blackout.

Using steady-state (power flow) analysis, investigators found that at 15:05, immediately prior to the tripping of FE Chamberlin-Harding 345-kV transmission line, the system was able to continue to operate reliably following the occurrence of any of more than 800 identified system contingencies, including the loss of the Chamberlin-Harding line. In other words, at 15:05 on August 14, 2003, the system was being operated within defined steady-state limits.

Low voltages were found in the Cleveland-Akron area operated by FE on August 14 prior to the blackout. These voltages placed the system at risk for voltage collapse. However, it can be said with certainty that low voltage or voltage collapse did not cause the August 14 blackout. P-Q and V-Q analysis by investigators determined that the FE system in northeastern Ohio was near a voltage collapse, but that events required to initiate a voltage collapse did not occur.

Investigators analyzed externalities that could have had adverse effects on the FE system in northeastern Ohio and determined that none of them caused the blackout. August 14 was warm in the Midwest and Northeast. Temperatures were above normal and there was very little wind, the weather was typical of a warm summer day. The warm weather caused electrical demand in northeastern Ohio to be high, but electrical demand was not close to a record level. Voltages were sagging in the Cleveland-Akron area due to a shortage of reactive power resources and the heavy air-conditioning loads, causing the FE system in that area to approach a voltage collapse condition.

Investigators also analyzed the interregional power transfers occurring on August 14 and determined that transfers across the area were high, but within studied limits and less than historical values and did not cause the blackout. Frequency anomalies on the Eastern Interconnection on August 14 prior to the blackout were determined to be caused by scheduling practices and were unrelated to the blackout.

In summary, prior to the 15:05 trip of the Chamberlin-Harding 345-kV line, the power system was within the operating limits defined by FE, although it was determined that FE had not effectively studied the minimum voltage and reactive supply criteria of its system in the Cleveland-Akron area. Investigators eliminated factors such as high power flows to Canada, low voltages earlier in the day or on prior days, the unavailability of specific generators or transmission lines (either individually or in combination with one another), and frequency anomalies as causes of the blackout.

B. Electric Demand and Comparisons to Historical Levels

August 14 was a hot summer day, but not unusually so. Temperatures were above normal throughout the northeast region of the United States and in eastern Canada. Electricity demand was high due to high air-conditioning loads typical of warm days in August. However, electricity demands were below record peaks. System operators had successfully managed higher demands both earlier in the summer and in previous years. Northern Ohio was experiencing an ordinary August afternoon, with loads moderately high to serve air-conditioning demand. FE imports into its Northern Ohio service territory that afternoon peaked at 2,853 MW, causing its system to consume high levels of reactive power.

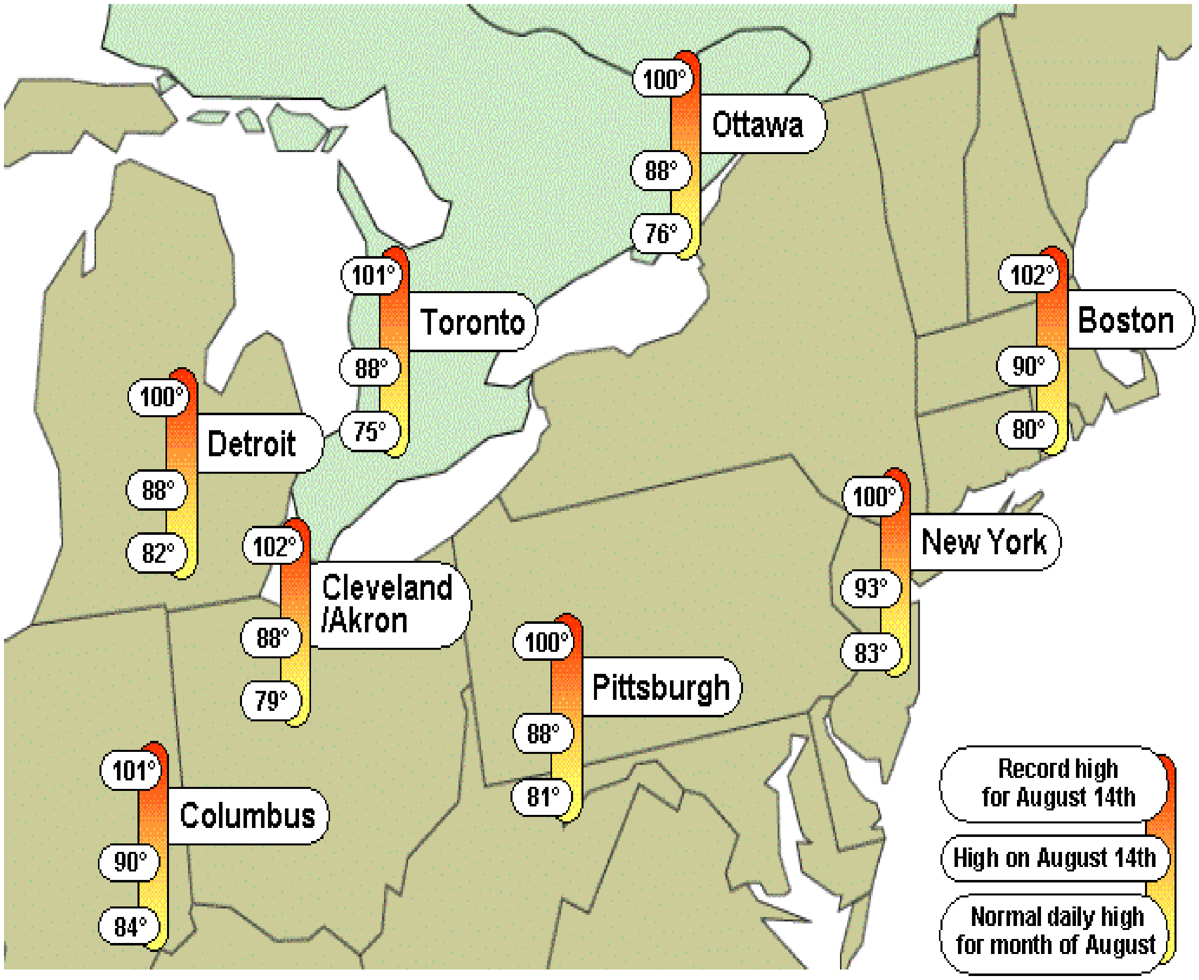


Figure II.1 — August 14 Temperatures in Northeastern United States and Eastern Canada

Table II.1 displays the peak load demands for AEP, Michigan Electric Coordinated System (MECS), FE, and PJM during the week of August 11, along with the temperatures measured at the Akron-Canton Airport. As the daily high temperature in northeastern Ohio (represented by temperatures at the Akron-Canton airport) increased from 78° F on August 11 to 87° F on August 14, the FE control area peak load demand increased by 20 percent from 10,095 MW to 12,165 MW. The loads in the surrounding systems experienced similar increases.

It is noteworthy that the FE control area peak load on August 14 was also the peak load for the summer of 2003, although it was not the all-time peak recorded for that system. That record was set on August 1, 2002, at 13,299 MW; 1,134 MW higher than on August 14, 2003. Given the correlation of load increase with ambient temperature, especially over a period of several days of warm weather, it is reasonable to assume that the load increase was due at least in part to the increased use of air conditioners. These increased air-conditioning loads lowered power factors compared to earlier in the week. These are important considerations when assessing voltage profiles, reactive reserves, and voltage stability.

Table II.1 — System Conditions for the Week August 11–14, 2003

All Load Values in MW	Monday Aug. 11	Tuesday Aug. 12	Wednesday Aug. 13	Thursday Aug. 14
Dry bulb temperature at Akron-Canton Airport	78° F	83° F	85° F	87° F
FE daily peak load in Northern Ohio (percent increase from August 11)	10,095	10,847 (7.5 percent)	11,556 (14.5 percent)	12,165 (20.5 percent)
MECS load at 14:00 (percent increase from August 11)	15,136	15,450 (2.1 percent)	17,335 (14.5 percent)	18,796 (24.2 percent)
AEP load at 14:00 (percent increase from August 11)	17,321	18,058 (4.3 percent)	18,982 (9.6 percent)	19,794 (14.3 percent)
PJM peak load (percent increase from August 11)	52,397	56,683 (8.2 percent)	58,503 (11.7 percent)	60,740 (15.9 percent)

As shown in Table II.2, FE's recorded peak electrical demands on August 14 and in prior months were well below the previously recorded peak demand.

Table II.2 — Loads on August 14 Compared to Summer 2003 and Summer 2002 Peaks

Month/Year	Actual Peak Load for Month	Date of Peak
August 2002	13,299 MW	August 1, 2002 (All-time peak)
June 2003	11,715 MW	
July 2003	11,284 MW	
August 2003	12,165 MW	August 14, 2003 (Summer 2003 Peak)

The day-ahead projections for the FE control area, as submitted to ECAR around 16:00 each afternoon that week, are shown in Table II.3. The projected peak load for August 14 was 765 MW lower than the actual FE load. FE load forecasts were low each day that week. FE forecasted that it would be a net importer over this period, peaking at 2,367 MW on August 14. Actual imports on August 14 peaked at 2,853 MW.

Table II.3 — FE Day-ahead Load Projections for Week of August 11–14, 2003

All values are in MW	Monday Aug. 11	Tuesday Aug. 12	Wednesday Aug. 13	Thursday Aug. 14
Projected Peak Load	10,300	10,200	11,000	11,400
Capacity Synchronized	10,335	10,291	10,833	10,840
Projected Import	1,698	1,800	1,818	2,367
Projected Export (to PJM)	1,378	1,378	1,278	1,278
Net Interchange (negative value is an import)	-320	-422	-540	-1,089
Spinning Reserve	355	513	373	529
Unavailable Capacity	1,100	1,144	1,263	1,433

C. Facilities out of Service

On any given day, generation and transmission capacity is unavailable; some facilities are out for routine maintenance, and others have been forced out by an unanticipated breakdown and need for repairs. August 14 was no exception.

1. Planned Generation Outages

Several key generators were out of service going into August 14.

Table II.4 — Key Generators Not Available on August 14, 2003

Generator	Rating		Reason for Outage
Davis-Besse Nuclear Unit	934 MW	481 Mvar	Prolonged NRC-ordered outage beginning on 3/22/02
Eastlake Unit 4	267 MW	150 Mvar	Forced outage on 8/13/03
Monroe Unit 1	780 MW	420 Mvar	Planned outage, taken out of service on 8/8/03
Cook Nuclear Unit 2	1,060 MW	460 Mvar	Outage began on 8/13/03
Conesville 5	400 MW	145 Mvar	Tripped at 12:05 on August 14 due to fan trip and high boiler drum pressure while returning a day early from a planned outage.

These generating units provide real and reactive power directly to the Cleveland, Toledo, and Detroit areas. Under routine practice, system operators take into account the unavailability of such units and any transmission facilities known to be out of service in the day-ahead planning studies they perform to determine the condition of the system for the next day. Knowing the status of key facilities also helps operators to determine in advance the safe electricity transfer levels for the coming day. MISO's day-ahead planning studies for August 14 took these generator outages and known transmission outages into account and determined that the regional system could be operated safely. Investigator analysis confirms that the unavailability of these generation units did not cause the blackout.

2. Transmission and Generating Unit Unplanned Outages Earlier in the Day of August 14

Several unplanned outages occurred on August 14 prior to 15:05. Around noon, several transmission lines in south-central Indiana tripped; at 13:31, the Eastlake 5 generating unit along the shore of Lake Erie tripped; at 14:02, the Stuart-Atlanta 345-kV line in southern Ohio tripped.

At 12:08, Cinergy experienced forced outages of its Columbus-Bedford 345-kV transmission line in south-central Indiana, the Bloomington-Denois Creek 230-kV transmission line, and several 138-kV lines. Although the loss of these lines caused significant voltage and facility loading problems in the Cinergy control area, they had no electrical effect on the subsequent events in northeastern Ohio leading to the blackout. The Cinergy lines remained out of service during the entire blackout (except for some reclosure attempts).

MISO operators assisted Cinergy by implementing TLR procedures to reduce flows on the transmission system in south-central Indiana. Despite having no direct electrical bearing on the blackout, these early events are of interest for three reasons:

- The Columbus-Bedford line trip was caused by a tree contact, which was the same cause of the initial line trips that later began the blackout sequence in northeastern Ohio. The Bloomington-Denois Creek 230-kV line tripped due to a downed conductor caused by a conductor sleeve failure.
- The Bloomington-Denois Creek 230-kV outage was not automatically communicated to the MISO state estimator and the missing status of this line caused a large mismatch error that stopped the MISO state estimator from operating correctly at about 12:15.

- Several hours before the start of the blackout, MISO was using the TLR procedure to offload flowgates in the Cinergy system following multiple contingencies. Although investigators believe this prior focus on TLR in Cinergy was not a distraction for later events that began in Ohio, it is indicative of the approach that was being used to address post-contingency facility overloads.

Eastlake Unit 5, located near Cleveland on the shore of Lake Erie, is a generating unit with a normal rating of 597 MW that is a major source of reactive power support for the Cleveland area. It tripped at 13:31 carrying 612 MW and 400 Mvar. The unit tripped because, as the Eastlake 5 unit operator sought to increase the unit's reactive power output in response to a request from the FE system operator, the unit's protection system detected an excitation (voltage control) system failure and tripped the unit off-line. The loss of the unit required FE to import additional power to make up for the loss of the 612 MW in the Cleveland area, made voltage management in northern Ohio more challenging, and gave FE operators less flexibility in operating their system. With two of Cleveland's generators already shut down (Davis-Besse and Eastlake 4), the loss of Eastlake 5 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 outages later that afternoon; with Eastlake 5 forced out of service, transmission line loadings were notably higher but well below ratings. The Eastlake 5 unit trip is described in greater detail in Section III.

The Stuart-Atlanta 345-kV line, a Dayton Power and Light (DP&L) tie to AEP that is in the PJM-West reliability coordination area, tripped at 14:02. The line tripped as the result of a tree contact and remained out of service during the entire blackout. System modeling showed that this outage was not related electrically to subsequent events in northern Ohio that led to the blackout. However, since the line was not in MISO's footprint, MISO operators did not monitor the status of this line and did not know that it had tripped out of service. Having an incorrect status for the Stuart-Atlanta line caused MISO's state estimator to continue to operate incorrectly, even after the previously mentioned mismatch was corrected.

D. Power Transfers and Comparisons to Historical Levels

On August 14, the flow of power through the ECAR region was heavy as a result of large transfers of power from the south (Tennessee, Kentucky, Missouri, etc.) and west (Wisconsin, Minnesota, Illinois, etc.) to the north (Michigan) and east (New York). The destinations for much of the power were northern Ohio, Michigan, and Ontario, Canada.

While heavy, these transfers were not beyond previous levels or in directions not seen before. The level of imports into Ontario on August 14 was high but not unusually so. Ontario's IMO is a frequent importer of power; depending on the availability and price of generation within Ontario. IMO had safely imported similar and even larger amounts of power several times during the summers of 2003 and 2002.

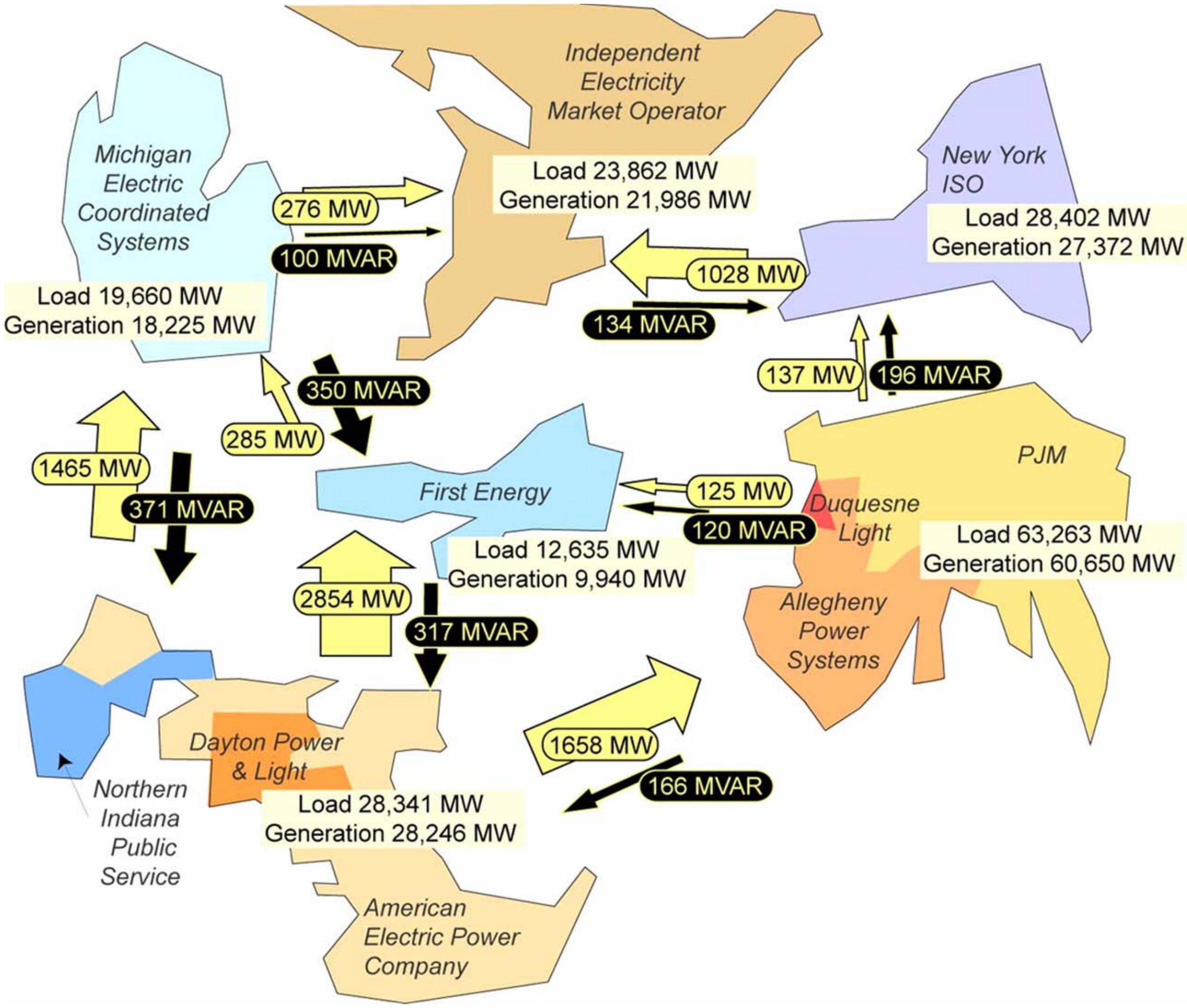


Figure II.2 — Generation, Demand, and Interregional Power Flows on August 14 at 15:05

Figure II.3 shows that the imports into the area comprising Ontario, New York, PJM, and ECAR on August 14 (shown by the red circles to be approximately 4,000 MW throughout the day) were near the peak amount of imports into that area for the period June 1 to August 13, 2003, although the August 14 imports did not exceed amounts previously seen.

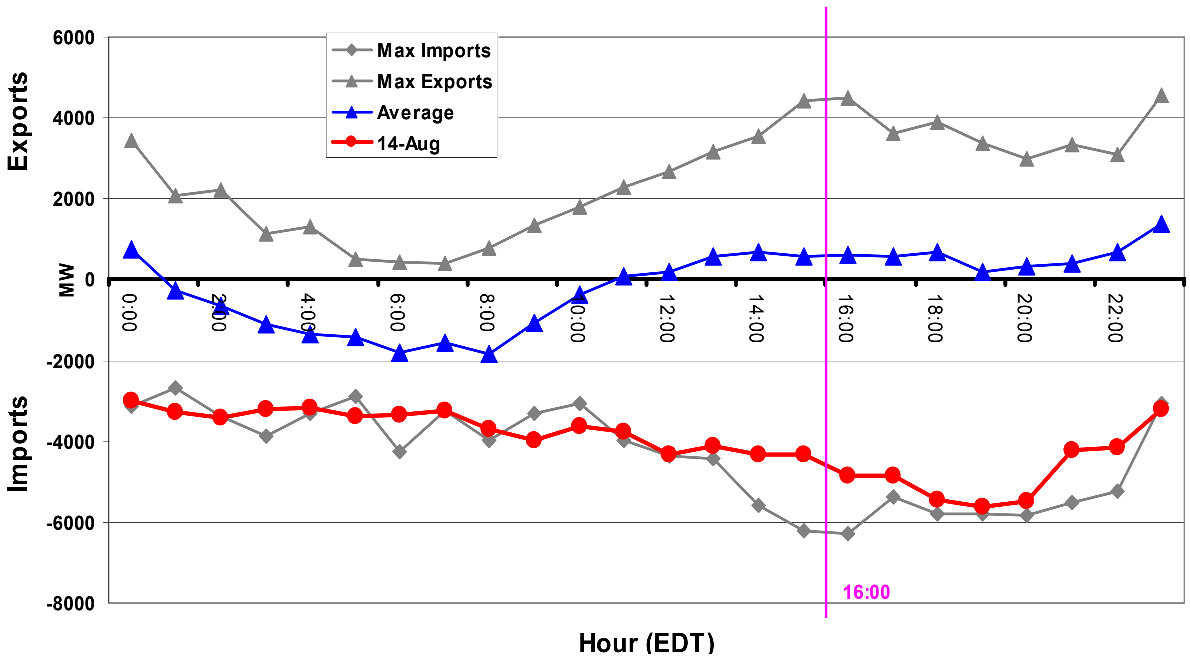


Figure II.3 — August 14, 2003, Northeast-Central Scheduled Transfers Compared to Historical Values

Figure II.4 shows the aggregated imports of the companies around Lake Erie, (MECS, IMO, FE, DLCO, NYISO, and PJM) for the peak summer days in 2002 and the days leading up to August 14, 2003. The comparison shows that the imports into the Lake Erie area were increasing in the days just prior to August 14, but that the level of these imports was lower than those recorded during the peak periods in the summer of 2002. Indeed, the import values in 2002 were about 20 percent higher than those recorded on August 14. Thus, although the imports into the Lake Erie area on August 14 were high, they were not unusually high compared to previous days in the week and were certainly lower than those recorded the previous summer.

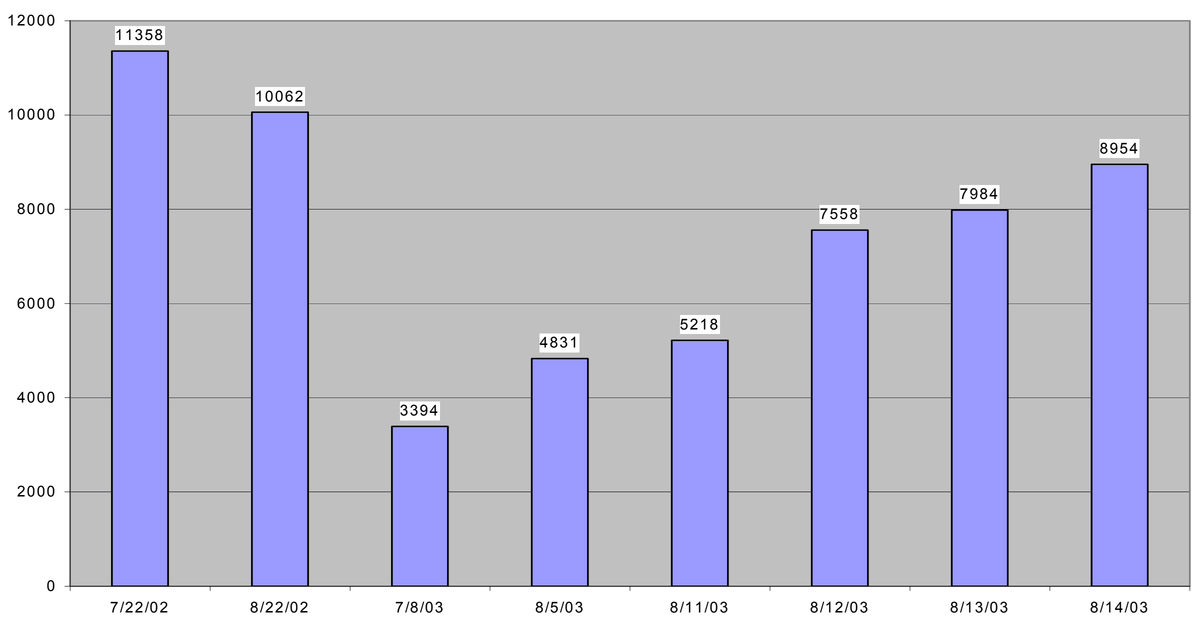


Figure II.4 — Imports for Lake Erie Systems

Another view of transfers is provided by examining the imports into IMO. Figure II.5 shows the total hourly imports into IMO for 2002 and 2003 for all days during July and August. These data show that the import levels in 2003 were generally lower compared to 2002 and that the peak import on August 14, 2003, at 2,130 MW at 14:00 was half the value recorded for the peak period in the summer of 2002.

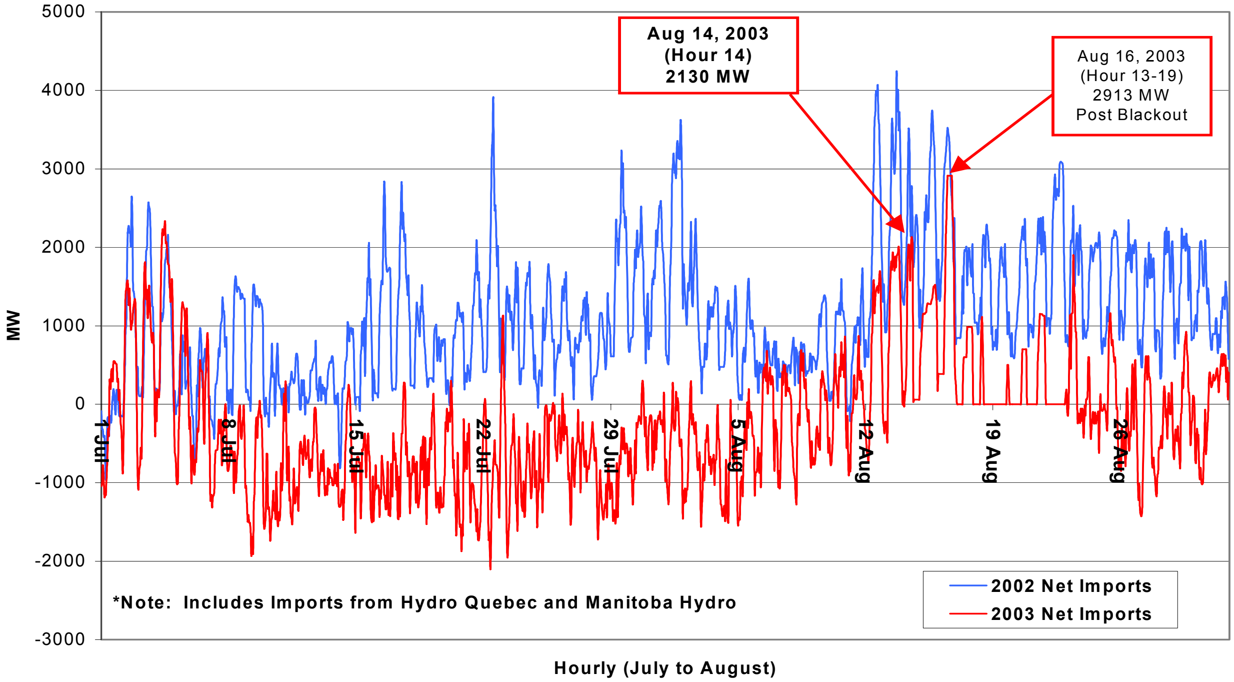


Figure II.5 — Hourly Imports into IMO

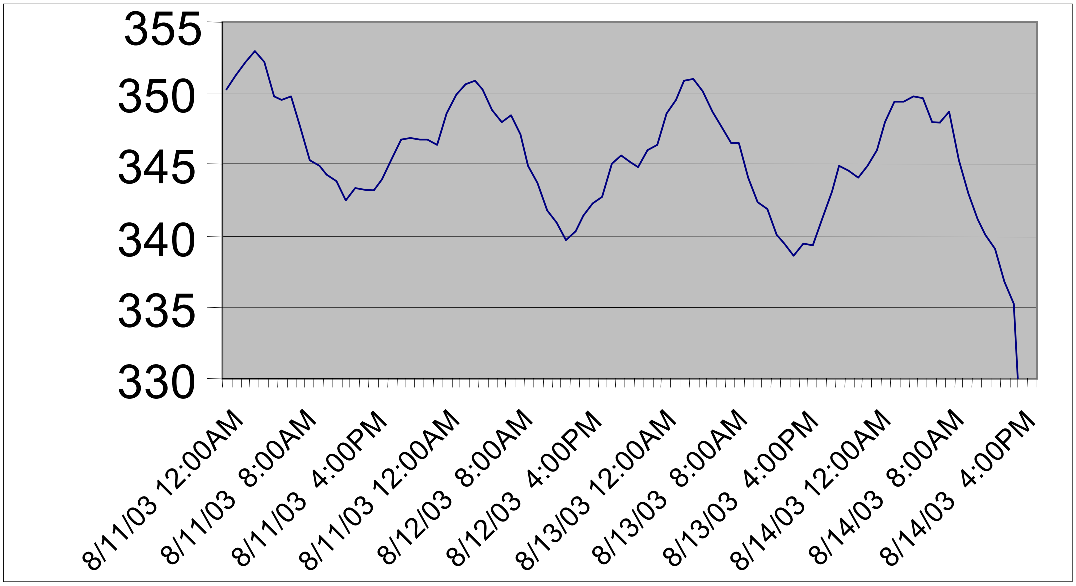
E. Voltage and Reactive Power Conditions Prior to the Blackout

1. FE Voltage Profiles

Unlike frequency, which is the same at any point in time across the interconnection, voltage varies by location and operators must monitor voltages continuously at key locations across their systems. During the days and hours leading up to the blackout, voltages were routinely depressed in a variety of locations in northern Ohio because of power transfers across the region, high air-conditioning demand, and other loads. During an interview, one FE operator stated, “some [voltage] sagging would be expected on a hot day, but on August 14 the voltages did seem unusually low.” However, as shown below in figures II.6 and II.7, actual measured voltage levels at key points on the FE transmission system on the morning of August 14 and up to 15:05 were within the range previously specified by FE as acceptable. Note, however, that most control areas in the Eastern Interconnection have set their low voltage limits at levels higher than those used by FE.

Generally speaking, voltage management can be especially challenging on hot summer days because of high transfers of power and high air-conditioning requirements, both of which increase the need for reactive power. Operators address these challenges through long-term planning, day-ahead planning, and real-time adjustments to operating equipment. On August 14, for example, investigators found that most systems in the northeastern portion of the Eastern Interconnection were implementing critical voltage procedures that are routinely used for heavy load conditions.

Figure II.6 — Representative Voltage Profile on FE System during Week of August 11



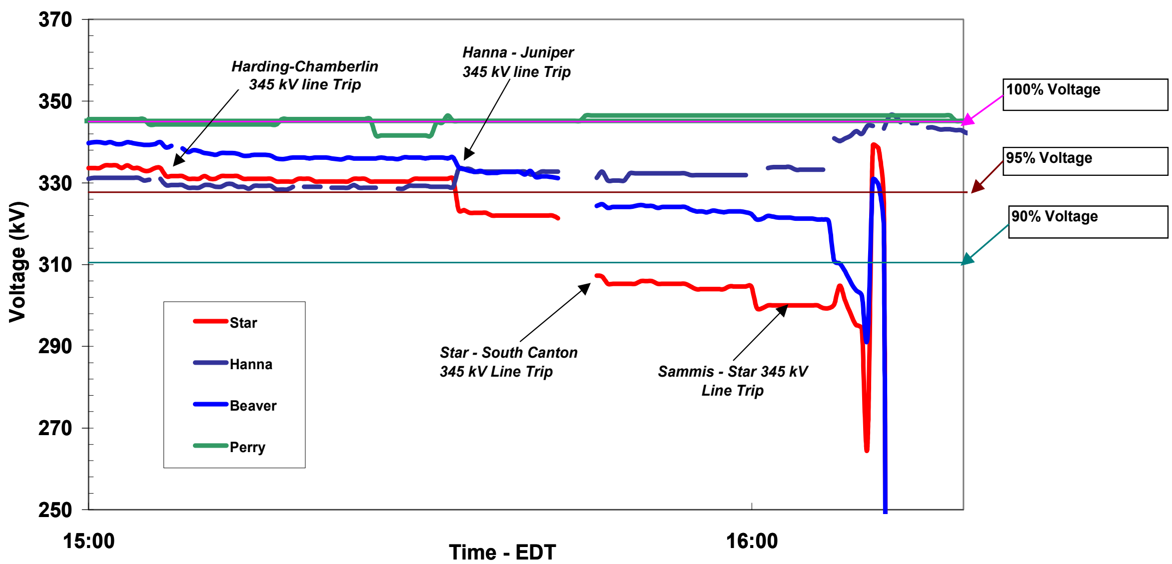


Figure II.7 — 345-kV Voltages in Northeastern Ohio on August 14, 2003

The existence of low voltages in northern Ohio is consistent with the patterns of power flow and composition of load on August 14. The power flow patterns for the region just before the Chamberlin-Harding line tripped at 15:05 show that FE was a major importer of power. Air-conditioning loads in the metropolitan areas around the southern end of Lake Erie were also consuming reactive power (Mvar). The net effect of the imports and load composition was to depress voltages in northern Ohio. Consistent with these observations, the analysis of reactive power flow shows that northern Ohio was a net importer of reactive power.

FE operators began to address voltage concerns early in the afternoon of August 14. For example, at 13:33, the FE operator requested that capacitors at Avon Substation be restored to service. From 13:13 through 13:28, the FE system operator called nine power plant operators to request additional voltage support from generators. He noted to most of them that system voltages were sagging. The operator called the following plants:

- Sammis plant at 13:13: "Could you pump up your 138 voltage?"
- West Lorain at 13:15: "Thanks. We're starting to sag all over the system."
- Eastlake at 13:16: "We got a way bigger load than we thought we would have. So we're starting to sag all over the system."
- Three calls to other plants between 13:20 and 13:23, stating to one: "We're sagging all over the system. I need some help." Asking another: "Can you pump up your voltage?"
- "Unit 9" at 13:24: "Could you boost your 345?" Two more at 13:26 and at 13:28: "Could you give me a few more volts?"
- Bayshore at 13:41 and Perry 1 operator at 13:43: "Give me what you can, I'm hurting."
- 14:41 to Bayshore: "I need some help with the voltage…I'm sagging all over the system…" The response to the FE Western Desk: "We're fresh out of vars."

Several station operators said that they were already at or near their reactive output limits. Following the loss of Eastlake 5 at 13:31, FE operators' concern about voltage levels was heightened. Again, while there was substantial effort to support voltages in the Ohio area, FE personnel characterized the conditions as not being unusual for a peak load day. No generators were asked to reduce their active power output to be able to produce more reactive output.

P-Q and V-Q analysis by investigators determined that the low voltages and low reactive power margins in the Cleveland-Akron area on August 14 prior to the blackout could have led to a voltage collapse. In other words, the FE system in northeastern Ohio was near a voltage collapse on August 14, although that was not the cause of the blackout.

The voltage profiles of the 345-kV network in the west-to-east and north-to-south directions were plotted from available SCADA data for selected buses. The locations of these buses are shown in Figures II.8 and II.9 respectively. They extend from Allen Junction, an FE interconnection point within ITC to the west, to Homer City in PJM to the east, and from St. Clair in ITC to the north to Cardinal-Tidd in AEP to the south.

There are three observations that can be made from these voltage profiles:

- The voltage profiles in both west-to-east and north-to-south directions display a dip at the center, with FE critical buses in the Cleveland-Akron area forming a low voltage cluster at Avon Lake, Harding, Juniper, Chamberlin, and Star.
- Voltages were observed to be higher in the portions of the FE control area outside of the Cleveland-Akron area. Voltages bordering FE in adjacent control areas were observed to be higher still. The bus voltages outside the Cleveland-Akron area are consistently higher during the period leading up to August 14.

- The bus voltages in the Cleveland-Akron area show a greater decline as the week progressed compared to buses outside this area.

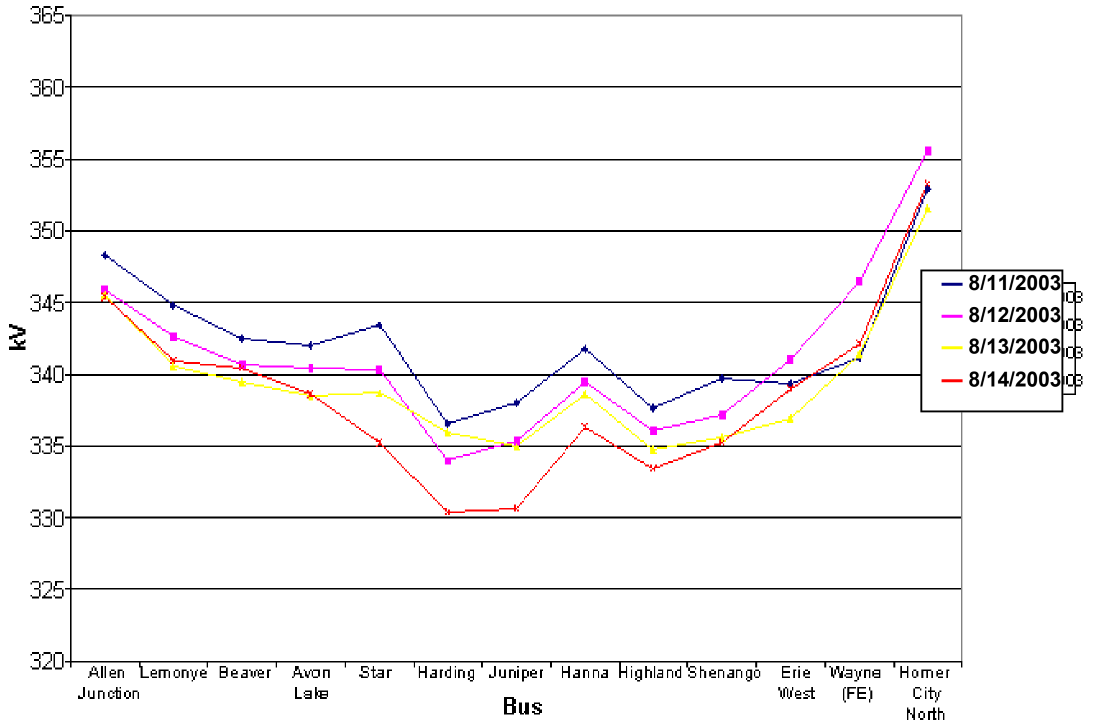


Figure II.8 — West-to-East Voltage Profile

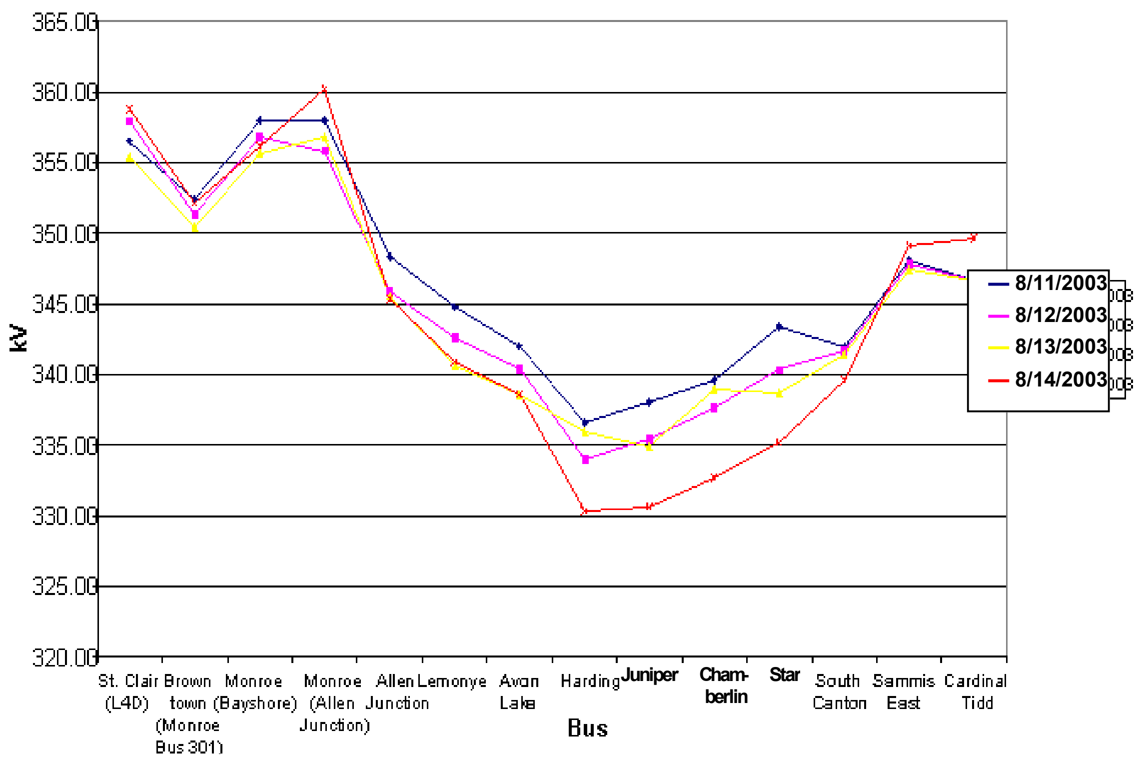


Figure II.9 — North-to-South Voltage Profile

Analysis showed that the declining voltages in the Cleveland-Akron area were strongly influenced by the increasing temperatures and loads in that area and minimally affected by transfers through FE to other systems. FE did not have sufficient reactive supply in the Cleveland-Akron area on August 14 to meet reactive power demands and maintain a safe margin from voltage collapse.

2. FE Reactive Reserves

Figure II.10 shows the actual reactive power reserves from representative generators along the Lake Erie shore and in the Cleveland-Akron area for three time periods on August 14. It also shows the reactive power reserves from representative generators in AEP, MECS, and PJM that are located in the proximity of their interconnections with FE.

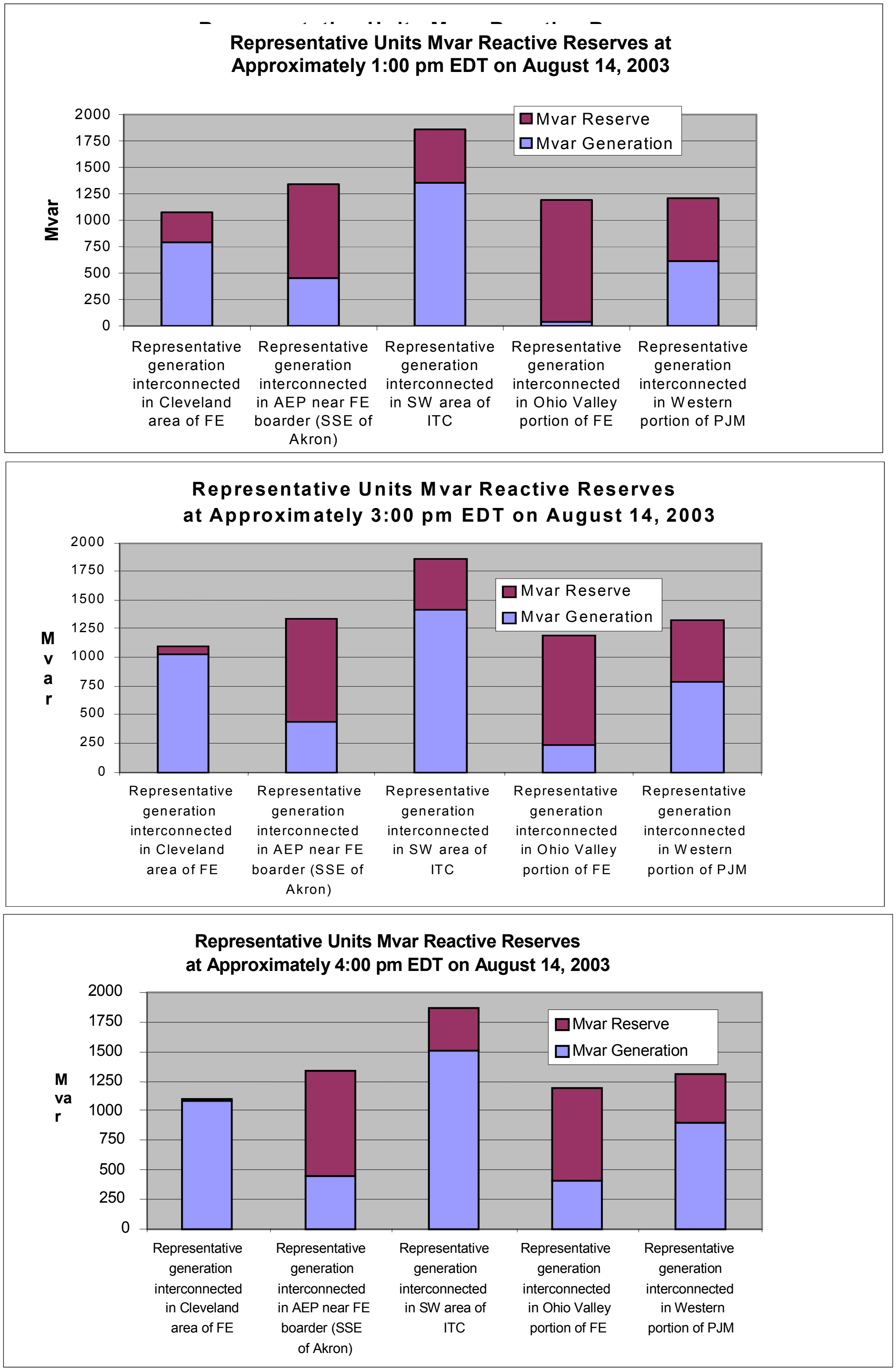


Figure II.10 — Reactive Reserves of Representative Groups of Generators on August 14, 2003

The following observations may be made:

- Reactive power reserves from the FE generators located in the Cleveland-Akron area were consistently lower than those from generators in both neighboring systems and in the southern portion of the FE system. These reserves were less than the reactive capability of the Perry nuclear generating station, the largest generating unit in the area, meaning that if the Perry unit had tripped offline, the Cleveland-Akron area would have been depleted of any reactive power reserve.
- The reactive reserves in the Cleveland-Akron area were progressively reduced as successive outages occurred on the afternoon of August 14. By 16:00, after numerous 138-kV line failures, the reserve margins in the Cleveland-Akron area were depleted.
- Generators external to this area had ample reactive margins while maintaining their scheduled voltages, but that reactive power was unable to reach the Cleveland-Akron area due to the limited ability of reactive power to flow over long distances. These included the generator group located southeast of Akron, consisting of Sammis, Beaver Valley, and Mansfield.

F. System Frequency

Figure II.11 shows a plot of the frequency for the Eastern Interconnection on August 14. As is typical, frequency is highly random within a narrow band of several one hundredths of a hertz. Prior to the blackout, frequency was within the statistical bounds of a typical day. Scheduled frequency was lowered to 59.98 at noon to conduct a time error correction. This is a routine operation. After the blackout, the frequency was high and highly variable following the loss of exports to the Northeast. Also, there appears to be a pattern relating to the times during which frequency deviations are larger.

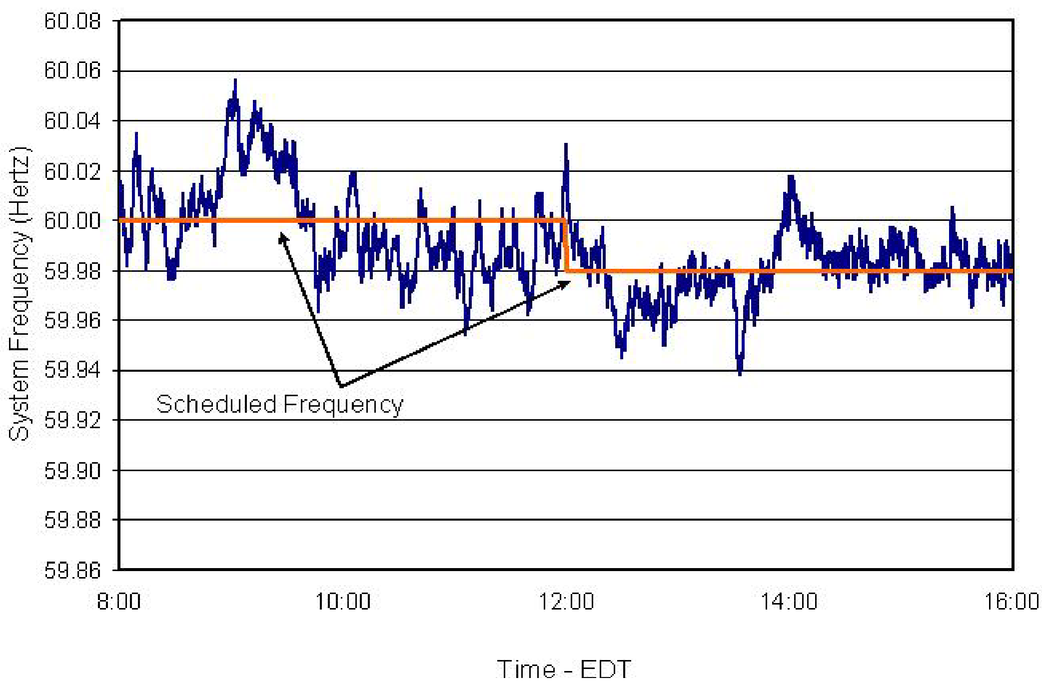


Figure II.11 — Eastern Interconnection Frequency Plot for August 14, 2003

System frequency anomalies earlier in the day on August 14 are explained by previously known interchange scheduling issues and were not a precursor to the blackout. Although frequency was somewhat variable on August 14, it was well within the bounds of safe operating practices as outlined in NERC operating policies and consistent with historical values.

Large signals in the random oscillations of frequency were seen on August 14, but this was typical for most other days as well, indicating a need for attention to the effects of scheduling interchange on interconnection frequency. Frequency generally appeared to be running high, which is not by itself a problem, but indicates that there were insufficient resources to control frequency for the existing scheduling practices. This behavior indicates that frequency anomalies seen on August 14 prior to the blackout were caused by the ramping of generation around regular scheduling time blocks and were neither the cause of the blackout nor precursor signals of a system failure. The results of this investigation should help to analyze control performance in the future.

G. Contingency Analysis of Conditions at 15:05 EDT on August 14

A power flow base case was established for 15:05 on August 14 that encompassed the entire northern portion of the Eastern Interconnection. Investigators benchmarked the case to recorded system conditions at that time. The team started with a projected summer 2003 power flow case developed in the spring of 2003 by the regional reliability councils. The level of detail involved in this region-wide study exceeded that normally considered by individual control areas and reliability coordinators. It consisted of a detailed representation of more than 44,300 buses, 59,086 transmission lines and transformers, and 6,987 major generators across the northern United States and eastern Canada. The team then revised the summer power flow case to match recorded generation, demand, and power interchange levels among control areas at 15:05 on August 14. The benchmarking consisted of matching the calculated voltages and line flows to recorded observations at more than 1,500 locations within the grid at 15:05.

Once the base case was benchmarked, the team ran a contingency analysis that considered more than 800 possible events as points of departure from the 15:05 case. None of these contingencies were found to result in a violation of a transmission line loading or bus voltage limit prior to the trip of the Chamberlin-Harding line in the FE system. According to these simulations, at 15:05, the system was able to continue to operate safely following the occurrence of any of the tested contingencies. From an electrical standpoint, the system was being operated within steady state limits at that time. Although the system was not in a reliable state with respect to reactive power margins, that deficiency did not cause the blackout.

III. Causal Events Leading to the Power System Cascade

This section explains the major events — electrical, operational, and computer-related — leading up to and causing the blackout. The period covered in this section begins at 12:15 EDT on August 14, when missing information on the Cinergy Bloomington-Denois Creek 230-kV line initially rendered MISO's state estimator ineffective. The section ends at 16:05:57 EDT on August 14, when the Sammis-Star 345-kV transmission line tripped, signaling the transition from a local event in northeastern Ohio to the start of an uncontrolled cascade that spread through much of northeastern North America.

A. Event Summary

At 13:31, the FE Eastlake 5 generating unit tripped offline due to an exciter failure while the operator was making voltage adjustments. Had Eastlake 5 remained in service, subsequent line loadings on the 345-kV paths into Cleveland would have been slightly lower and outages due to tree contacts might have been delayed; there is even a remote possibility that the line trips might not have occurred. Loss of Eastlake 5, however, did not cause the blackout. Analysis shows that the FE system was still operating within FE-defined limits after the loss of Eastlake 5.

Shortly after 14:14, the alarm and logging system in the FE control room failed and was not restored until after the blackout. Loss of this critical control center function was a key factor in the loss of situational awareness of system conditions by the FE operators. Unknown to the operators, the alarm application failure eventually spread to a failure of multiple energy management system servers and remote consoles, substantially degrading the capability of the operators to effectively monitor and control the FE system. At 14:27, the Star-South Canton 345-kV tie line between FE and AEP opened and reclosed. When AEP operators called a few minutes later to confirm the operation, the FE operators had no indication of the operation (since the alarms were out) and denied their system had a problem. This was the first clear indication of a loss of situational awareness by the FE operators.

Between 15:05 and 15:42, three FE 345-kV transmission lines supplying the Cleveland-Akron area tripped and locked out because the lines contacted overgrown trees within their rights-of-way. At 15:05, while loaded at less than 45 percent of its rating, FE's Chamberlin-Harding 345-kV line tripped and locked out. No alarms were received in the FE control room because of the alarm processor failure, and the operators' loss of situational awareness had grown from not being aware of computer problems to not being aware of a major system problem. After 15:05, following the loss of the Chamberlin-Harding line, the power system was no longer able to sustain the next-worst contingency without overloading facilities above emergency ratings.

The loss of two more key 345-kV lines in northern Ohio due to tree contacts shifted power flows onto the underlying network of 138-kV lines. These lines were not designed to carry such large amounts of power and quickly became overloaded. Concurrently, voltages began to degrade in the Akron area. As a result of the increased loading and decaying voltages, sixteen 138-kV lines tripped sequentially over a period of 30 minutes (from 15:39 to 16:09), in what can best be described as a cascading failure of the 138-kV system in northern Ohio. Several of these line trips were due to the heavily loaded lines sagging into vegetation, distribution wires, and other underlying objects.

Loss of the 138-kV paths, along with the previous loss of the 345-kV paths into Cleveland, overloaded the remaining major path into the area: the FE Sammis-Star 345-kV line. Sammis-Star tripped at 16:05:57, signaling the beginning of an uncontrollable cascade of the power system. The trip was a pivotal point between a localized problem in northeastern Ohio and what became a wide-area cascade affecting eight states and two provinces. The loss of the heavily overloaded Sammis-Star line instantly created major and unsustainable burdens on other lines, first causing a "domino-like" sequence of line outages westward and northward across Ohio and into Michigan, and then eastward, splitting New York from Pennsylvania and New Jersey. The cascade sequence after the Sammis-Star trip is described in Section IV.

Although overgrown trees caused an unexpected rash of non-random line trips on the FE system, and FE operating personnel lost situational awareness, there could have been assistance from MISO, FE's reliability coordinator, had it not been for lack of visual tools and computer problems there as well. The first sign of trouble came at 12:15, when MISO's state estimator experienced an unacceptably large mismatch error between state-estimated values and measured values. The error was traced to an outage of Cinergy's Bloomington-Denois Creek 230-kV line that was not updated in MISO's state estimator. The line status was quickly corrected, but the MISO analyst forgot to reset the state estimator to run automatically every five minutes.

At 14:02, DP&L's Stuart-Atlanta 345-kV line tripped and locked out due to a tree contact. By the time the failure to reset the MISO state estimator to run automatically was discovered at 14:40, the state estimator was missing data on the Stuart-Atlanta outage and, when finally reset, again failed to solve correctly. This combination of human error and ineffective updating of line status information to the MISO state estimator prevented the state estimator from operating correctly from 12:15 until 15:34. MISO's real-time contingency analysis, which relies on state estimator input, was not operational until 16:04. During this entire time, MISO was unable to correctly identify the contingency overload that existed on the FE system after the Chamberlin-Harding line outage at 15:05, and could not recognize worsening conditions as the Hanna-Juniper and Star-South Canton lines also failed. MISO was still receiving data from FE during this period, but was not aware of the line trips.

By around 15:46, when FE, MISO, and neighboring systems had begun to realize that the FE system was in serious jeopardy, the only practical action to prevent the blackout would have been to quickly drop load. Analysis indicated that at least 1,500 to 2,500 MW of load in the Cleveland-Akron area would have had to been shed. However, no such effort was made by the FE operators. They still lacked sufficient awareness of system conditions at that time and had no effective means to shed an adequate amount of load quickly. Furthermore, the investigation found that FE had not provided system operators with the capability to manually or automatically shed that amount of load in the Cleveland area in a matter of minutes, nor did it have operational procedures in place for such an action.

B. Significant Events Prior to the Start of the Blackout

1. Eastlake Unit 5 Trips at 13:31 EDT

Eastlake Unit 5 is located in northern Ohio along the southern shore of Lake Erie. 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. This also increased the importance of the Eastlake 5 and Perry 1 units as resources in that area.

Throughout the morning, the EMS operators were calling the plants to request increases in reactive power. A key conversation took place between the EMS (system control center) operator and the Eastlake Unit 5 operator at approximately 13:16 on August 14:

> EMS Operator: "Hey, do you think you could help out the 345 voltage a little?"
>
> Eastlake 5 Operator: "Buddy, I am — yeah, I'll push it to my max max. You're only going to get a little bit."
>
> EMS Operator: "That's okay, that's all I can ask."

The effects of the plant operator trying to go to "max max" at 13:16 are apparent in Figure III.1. The reactive output rose above the assumed maximum for about four minutes. There is a slight step increase in the reactive output of the unit again. This increase is believed to correlate with the trip of a 138-kV capacitor bank in the FE system that field personnel were attempting to restore to service. The reactive output remains at this level for another three to four minutes and then the Automatic Voltage Regulator (AVR) tripped to manual operation and a set point that effectively brought the (gross) Mvar output of the unit to zero. When a unit at full MW load trips from AVR to manual control, the Mvar output should not be designed or set to decrease the Mvar output to zero. Normal practice is to decrease the exciter to the rated full load DC field current or a reasonable preset value. Subsequent investigation found that this unit was set incorrectly.

About four or five minutes after the Mvar output decreased to zero, the operator was increasing the terminal voltage and attempting to place the exciter back on AVR control when the excitation system tripped altogether (see Figure III.1). The unit then tripped off at 13:31:34 when the loss of excitation relay operated. Later phone transcripts indicate subsequent trouble with a pump valve at the plant that would not re-seat after the trip. As a result, the unit could not be quickly returned to service.

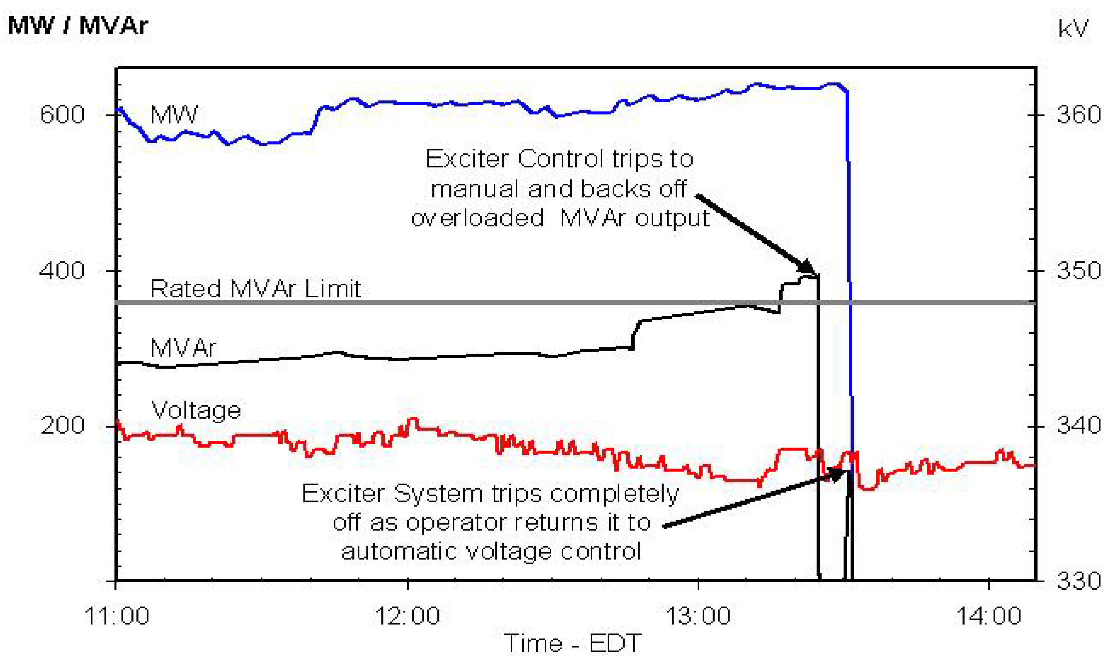


Figure III.1 — Eastlake 5 Output Prior to Trip at 13:31 EDT

The excitation system failure not only tripped the Eastlake unit 5 — a critical unit in the Cleveland area — the effort to increase Eastlake 5 voltage did not produce the desired result. Rather, the result of trying to increase the reactive output of the Eastlake 5 generating unit, once the unit tripped, was a decrease in reactive support to the Cleveland-Akron area.

At no time during the morning or early afternoon of August 14 did the FE operators indicate voltage problems or request any assistance from outside the FE control area for voltage support. FE did not report the loss of Eastlake Unit 5 to MISO. Further, MISO did not monitor system voltages; that responsibility was left to its member operating systems.

When Eastlake 5 tripped, flows caused by replacement power transfers and the associated reactive power to support these additional imports into the area contributed to higher line loadings on the paths into the Cleveland area. At 15:00, FE load was approximately 12,080 MW, and FE was importing about 2,575 MW, or 21 percent of the total load. With imports this high, FE reactive power demands, already high due to the increasing air-conditioning loads that afternoon, were using up nearly all available reactive resources.

Simulations indicate that the loss of Eastlake 5 was an electrically significant step in the sequence of events, although it was not a cause of the blackout. However, contingency analysis simulation of the conditions immediately following the loss of the Chamberlin-Harding 345-kV circuit at 15:05 shows that the system was unable to sustain the next worst contingency event without exceeding emergency ratings. In other words, with Eastlake 5 out of service, the FE system was in a first contingency limit violation after the loss of the Chamberlin-Harding 345-kV line. However, when Eastlake 5 was modeled as being in service, all contingency violations were eliminated, even after the loss of Chamberlin-Harding.

FE operators did not access contingency analysis results at any time during the day on August 14, nor did the operators routinely conduct such studies on shift. In particular, the operators did not use contingency analysis to evaluate the loss of Eastlake 5 at 13:31 to determine whether the loss of another line or generating unit would put their system at risk. FE operators also did not request or evaluate a contingency analysis after the loss of Chamberlin-Harding at 15:05 (in part because they did not know that it had tripped out of service). Thus, FE did not discover at 15:05, after the Chamberlin-Harding line trip, that their system was no longer within first contingency criteria and that operator action was needed to immediately begin correcting the situation.

FE had a state estimator that ran automatically every 30 minutes. The state estimator solution served as a base from which to perform contingency analyses. Interviews of FE personnel indicate that the contingency analysis model was likely running on August 14, but it was not consulted at any point that afternoon. FE indicated that it had experienced problems with the automatic contingency analysis operation since the system was installed in 1995. As a result, the practice was for FE operators or engineers to run contingency analysis manually as needed.

2. Stuart-Atlanta 345-kV Line Trips at 14:02 EDT

The Stuart-Atlanta 345-kV line is in the DP&L control area. After the Stuart-Atlanta line tripped, DP&L did not immediately provide an update of a change in equipment status using a standard form that posts the status change in the NERC System Data Exchange (SDX). The SDX is a database that maintains information on grid equipment status and relays that information to reliability coordinators, control areas, and the NERC IDC. The SDX was not designed as a real-time information system, and DP&L was required to update the line status in the SDX within 24 hours. MISO, however, was inappropriately using the SDX to update its real-time state estimator model. On August 14, MISO checked the SDX to make sure that it had properly identified all available equipment and outages, but found no posting there regarding the Stuart-Atlanta outage.

At 14:02:00 the Stuart-Atlanta line tripped and locked out due to contact with a tree. Investigators determined that the conductor had contacted five 20–25 feet tall Ailanthus trees, burning off the tops of the trees. There was no fire reported on the ground and no fire agencies were contacted, disproving claims that the outage had been caused by ionization of the air around the conductors induced by a ground fire. Investigation modeling reveals that the loss of the Stuart-Atlanta line had no adverse electrical effect on power flows and voltages in the FE area, either immediately after its trip or later that afternoon. The Stuart-Atlanta line outage is relevant to the blackout only because it contributed to the failure of MISO's state estimator to operate effectively, and MISO was unable to provide adequate diagnostic support to FE until 16:04.

3. Star-South Canton 345-kV Line Trip and Reclose

At 14:27:16, while loaded at about 54 percent of its emergency ampere rating, the Star-South Canton 345-kV tie line (between AEP and FE) tripped and successfully reclosed. The digital fault recorder indicated a solid Phase C-to-ground fault near the FE Star station. The South Canton substation produced an alarm in AEP's control room. However, due to the FE computer alarm system failure beginning at 14:14, the line trip and reclosure at FE Star substation were not alarmed at the FE control center. The FE operators had begun to lose situational awareness of events occurring on their system as early as 14:27, when the Star-South Canton line tripped momentarily and reclosed. Figure III.2 presents the initial events: the Eastlake 5 trip, the Stuart-Atlanta trip, and the Star-South Canton trip and reclose.

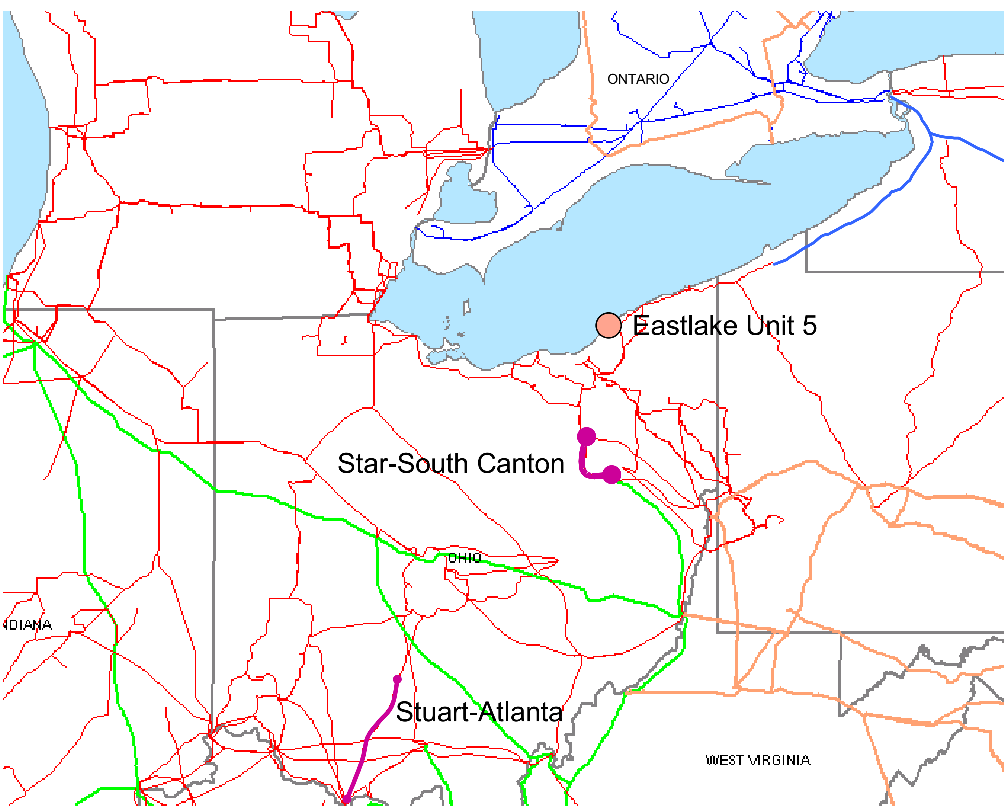


Figure III.2 — Initial Events

C. FE Computer System Failures: Loss of Situational Awareness

1. Alarm Processor Failure at 14:14 EDT

Starting around 14:14, FE control room operators lost the alarm function that provided audible and visual indications when a significant piece of equipment changed from an acceptable to problematic status. Analysis of the alarm problem performed by FE after the blackout suggests that the alarm processor essentially "stalled" while processing an alarm event. With the software unable to complete that alarm event and move to the next one, the alarm processor buffer filled and eventually overflowed. After 14:14, the FE control computer displays did not receive any further alarms, nor were any alarms being printed or posted on the EMS's alarm logging facilities.

FE operators relied heavily on the alarm processor for situational awareness, since they did not have any other large-scale visualization tool such as a dynamic map board. The operators would have been only partially handicapped without the alarm processor, had they known it had failed. However, by not knowing that they were operating without an alarm processor, the operators did not recognize system conditions were changing and were not receptive to information received later from MISO and neighboring systems. The operators were unaware that in this situation they needed to manually, and more closely, monitor and interpret the SCADA information they were receiving.

Cause 1a[2]: FE had no alarm failure detection system. Although the FE alarm processor stopped functioning properly at 14:14, the computer support staff remained unaware of this failure until the second EMS server failed at 14:54, some 40 minutes later. Even at 14:54, the responding support staff understood only that all of the functions normally hosted by server H4 had failed, and did not realize that the alarm processor had failed 40 minutes earlier. Because FE had no periodic diagnostics to evaluate and report the state of the alarm processor, nothing about the eventual failure of two EMS servers would have directly alerted the support staff that the alarms had failed in an infinite loop lockup — or that the alarm processor had failed in this manner both earlier and independently of the server failure events. Even if the FE computer support staff had communicated the EMS failure to the operators (which they did not) and fully tested the critical functions after restoring the EMS (which they did not), there still would have been a minimum of 40 minutes, from 14:14 to 14:54, during which the support staff was unaware of the alarm processor failure.

Working under the assumption that their power system was in satisfactory condition and lacking any EMS alarms to the contrary, FE control room operators were surprised when they began receiving telephone calls from others — MISO, AEP, PJM, and FE field operations staff — who offered information on the status of FE transmission facilities that conflicted with the FE system operators' understanding of the situation. The first hint to FE control room staff of any computer problems occurred at 14:19, when a caller and an FE control room operator discussed the fact that three sub-transmission center dial-ups had failed. At 14:25, a control room operator talked again with a caller about the failure of these three remote terminals. The next hint came at 14:32, when FE scheduling staff spoke about having made schedule changes to update the EMS pages, but that the totals did not update.

There is an entry in the FE western desk operator's log at 14:14 referring to the loss of alarms, but it appears that entry was made after-the-fact, referring back to the time of the last known alarm.

[2] Causes appear in chronological order. Their numbering, however, corresponds to overall categorization of causes summarized in Section V.

If any operator knew of the alarm processor failure prior to 15:42, there was no evidence from the phone recordings, interview transcripts, or written logs that the problem was discussed during that time with any other control room staff or with computer support staff.

Although the alarm processing function failed, the remainder of the EMS continued to collect valid real-time status information and measurements for the FE power system, and continued to have supervisory control over the FE system. The FE control center continued to send its normal complement of information to other entities, including MISO and AEP. Thus, these other entities continued to receive accurate information about the status and condition of the FE power system, even past the point when the FE alarm processor failed. However, calls received later from these other entities did not begin to correct the FE operators' loss of situational awareness until after 15:42.

2. Remote Console Failures between 14:20 and 14:25 EDT

Between 14:20 and 14:25, several FE remote control terminals in substations ceased to operate. FE advised the investigation team that it believes this occurred because the data feeding into those terminals started "queuing" and overloading the terminals' buffers. FE system operators did not learn about the remote terminal failures until 14:36, when a technician at one of the sites noticed the terminal was not working after he came on early for the shift starting at 15:00 and called the main control room to report the problem. As remote terminals failed, each triggered an automatic page to FE computer support staff. 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.

3. FE EMS Server Failures

The FE EMS system includes several server nodes that perform the advanced EMS applications. Although any one of them can host all of the functions, normal FE system configuration is to have several host subsets of applications, with one server remaining in a "hot-standby" mode as a backup to the other servers, should any fail. At 14:41, the primary server hosting the EMS alarm processing application failed, due either to the stalling of the alarm application, the "queuing" to the remote terminals, or some combination of the two. Following pre-programmed 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 back-up while still stalled and ineffective, the back-up server failed 13 minutes later, at 14:54. Accordingly, all of the EMS applications on these two servers stopped running.

The concurrent loss of two EMS servers apparently caused several new problems for the FE EMS and the system operators using 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 refreshes displays on operators' computer consoles. Thus, at times on August 14, operator screen refresh rates, normally one-to-three 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 from one or more top level screens, the operators' primary tool for observing system conditions slowed to a frustrating crawl. This situation likely occurred between 14:54 and 15:08, when both servers failed, and again between

15:46 and 15:59, while FE computer support personnel attempted a "warm reboot" of both servers to remedy the alarm problem.[3]

Loss of the first server caused an auto-page to be issued to alert the FE EMS computer support personnel to the problem. When the back-up server failed, it too sent an auto-page to FE computer support staff. At 15:08, the support staff completed a warm reboot. Although the FE computer support staff should 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 or when they completed the primary server restart at 15:08. At 15:42, a member of the computer support staff was told of the alarm problem by a control room operator. FE has stated to investigators that their computer support staff had been unaware before then that the alarm processing sub-system of the EMS was not working.

Startup diagnostics monitored during that warm reboot verified that the computer and all expected processes were running. Accordingly, the FE computer support 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 computer support staff did not confirm with the control room operators that the alarm system was again working properly.

Cause 1b: FE computer support staff did not effectively communicate the loss of alarm functionality to the FE system operators after the alarm processor failed at 14:14, nor did they have a formal procedure to do so. Knowing the alarm processor had failed would have provided FE operators the opportunity to detect the Chamberlin-Harding line outage shortly after 15:05 using supervisory displays still available in their energy management system. Knowledge of the Chamberlin-Harding line outage would have enabled FE operators to recognize worsening conditions on the FE system and to consider manually reclosing the Chamberlin-Harding line as an emergency action after subsequent outages of the Hanna-Juniper and Star-South Canton 345-kV lines. Knowledge of the alarm processor failure would have allowed the FE operators to be more receptive to information being received from MISO and neighboring systems regarding degrading conditions on the FE system. This knowledge would also have allowed FE operators to warn MISO and neighboring systems of the loss of a critical monitoring function in the FE control center computers, putting them on alert to more closely monitor conditions on the FE system, although there is not a specific procedure requiring FE to warn MISO of a loss of a critical control center function. The FE operators were complicit in this deficiency by not recognizing the alarm processor failure existed, although no new alarms were received by the operators after 14:14. A period of more than 90 minutes elapsed before the operators began to suspect a loss of the alarm processor, a period in which, on a typical day, scores of routine alarms would be expected to print to the alarm logger.

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 operators could not manage affiliated power plants on pre-set programs to respond automatically to meet FE system load and interchange obligations. Although the AGC did not

[3] 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 whereby only that node is shut down and restarted. 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 computer support personnel on August 14 were warm reboots. A cold reboot was done in the early morning of August 15, which corrected the alarm problem.

work from 14:54 to 15:08 and again from 15:46 to 15:59 (periods when both servers were down), this loss of functionality does not appear to have had any causal effect on the blackout.

The concurrent loss of the EMS servers also caused the failure of the FE strip chart function. Numerous strip charts are visible in the FE control room, driven by the EMS computers. They show a variety of system conditions including raw ACE (Area Control Error), FE system load, and Sammis-South Canton and Star-South Canton line loadings. The chart recorders 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 operator noticed or reported the failed operation of the charts. 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.

Without an effective EMS, 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 the alarm processing on the EMS was not working and, subsequently, did not monitor other available telemetry. Shortly after 14:14 when their EMS alarms failed, and until at least 15:42 when they began to recognize the gravity of 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 system conditions was in error, despite receiving clues via phone calls from AEP, PJM, MISO, and customers. The FE operators were not aware of line outages that occurred after the trip of Eastlake 5 at 13:31 until approximately 15:45, although they were beginning to get external input describing aspects of the system's weakening condition. Since FE 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. Unknowingly, they used the outdated system condition information they did have to discount information received from others about growing system problems.

Cause 1c: FE control center computer support staff did not fully test the functionality of applications, including the alarm processor, after a server failover and restore. After the FE computer support staff conducted a warm reboot of the energy management system to get the failed servers operating again, they did not con-duct a sufficiently rigorous test of critical energy management system applications to determine that the alarm processor failure still existed. Full testing of all critical energy management functions after restoring the servers would have detected the alarm processor failure as early as 15:08 and would have cued the FE system operators to use an alternate means to monitor system conditions. Knowledge that the alarm processor was still failed after the server was restored would have enabled FE operators to proactively monitor sys-tem conditions, become aware of the line outages occurring on the system, and act on operational information that was received. Knowledge of the alarm processor failure would also have allowed FE operators to warn MISO and neighboring systems, assuming there was a procedure to do so, of the loss of a critical monitoring function in the FE control center computers, putting them on alert to more closely monitor conditions on the FE system.

4. FE EMS History

The EMS in service at the FE 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 to this EMS were made in 1998, although more recent updates were available from the vendor. On August 14, the system was not running the most recent release of the XA21 software. FE had decided well before then to replace its XA21 system with an EMS from another vendor.

> ***Cause 1d: FE operators did not have an effective alternative to easily visualize the overall conditions of the system once the alarm processor failed.*** An alternative means of readily visualizing overall system conditions, including the status of critical facilities, would have enabled FE operators to become aware of forced line outages in a timely manner even though the alarms were non-functional. Typically, a dynamic map board or other type of display could provide a system status overview for quick and easy recognition by the operators. As with the prior causes, this deficiency precluded FE operators from detecting the degrading system conditions, taking corrective actions, and alerting MISO and neighboring systems.

FE personnel told the investigation team that the alarm processing application had failed on several occasions prior to August 14, leading to loss of the alarming of system conditions and events for FE operators. This was, however, the first time the alarm processor had failed in this particular mode in which the alarm processor completely locked up due to XA21 code errors. FE computer support personnel neither recognized nor knew how to correct the alarm processor lock-up. FE staff told investigators that it was only during a post-outage support call with GE late on August 14 that FE and GE determined that the only available course of action to correct the alarm problem was a cold reboot of the XA21 system. In interviews immediately after the blackout, FE computer support 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. However, the support staff decided not to take such action because the operators considered power system conditions to be precarious and operators were concerned about the length of time that the reboot might take and the reduced capability they would have until it was completed.

D. The MISO State Estimator Is Ineffective from 12:15 to 16:04 EDT

It is common for reliability coordinators and control areas to use a state estimator to monitor the power system to improve the accuracy over raw telemetered data. The raw data are processed mathematically to make a "best fit" power flow model, which can then be used in other software applications, such as real-time contingency analysis, to simulate various conditions and outages to evaluate the reliability of the power system. Real-time contingency analysis is used to alert operators if the system is operating insecurely; it can be run either on a regular schedule (e.g., every five 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 its state estimator every five minutes and contingency analysis less frequently. If the model does not have accurate and timely information about key facilities, then 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. On August 14, MISO's state estimator and real-time contingency analysis tools were still under development and not fully mature. At about 12:15, MISO's state estimator produced a solution with a large mismatch outside the acceptable tolerance. This was traced to the outage at 12:12:47 of Cinergy's Bloomington-Denois Creek 230-kV line. This line tripped out due to a sleeve failure. Although this line was out of service, its status was not updated in the state estimator.

Line status information within MISO's reliability coordination area is transmitted to MISO by the ECAR data network or direct links intended to be automatically linked to the state estimator. This requires coordinated data naming as well as instructions that link the data to the tools. For the Bloomington-Denois Creek line, the automatic linkage of line status to the state estimator had not yet been established. The line status was corrected manually and MISO's analyst obtained a good state estimator solution at about 13:00 and a real-time contingency analysis solution at 13:07. However, to troubleshoot this problem, he had turned off the automatic trigger that runs the state estimator every five minutes. After fixing the problem he forgot to re-enable the automatic trigger. So, although he had manually run the state estimator and real-time contingency analysis 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.

The fact that the state estimator was not running automatically on its regular five-minute schedule was discovered at about 14:40. The automatic trigger was re-enabled but again the state estimator failed to solve successfully. This time, the investigation identified the Stuart-Atlanta 345-kV line outage at 14:02 to be the likely cause. This line, jointly owned by DP&L and AEP, is monitored by DP&L. The line is under PJM's reliability umbrella rather than MISO's. Even though it affects electrical flows within MISO and could stall MISO's state estimator, the line's status had not been automatically linked to MISO's state estimator.

Cause 3a: MISO was using non-real-time information to monitor real-time operations in its area of responsibility. MISO was using its Flowgate Monitoring Tool (FMT) as an alternative method of observing the real-time status of critical facilities within its area of responsibility. However, the FMT was receiving information on facility outages from the NERC SDX, which is not intend-ed as a real-time information system and is not required to be updated in real-time. Therefore, without real-time outage information, the MISO FMT was unable to accurately estimate real-time conditions within the MISO area of responsibility. If the FMT had received accurate line outage distribution factors representing current system topology, it would have identified a contingency overload on the Star-Juniper 345-kV line for the loss of the Hanna-Juniper 345-kV line as early as 15:10. This information would have enabled MISO to alert FE operators regarding the contingency violation and would have allowed corrective actions by FE and MISO. The reliance on non-real-time facility status information from the NERC SDX is not limited to MISO; others in the Eastern Interconnection use the same SDX information to calculate TLR curtailments in the IDC and make operational decisions on that basis. What was unique compared to other reliability coordinators on that day was MISO's reliance on the SDX for what they intended to be a real-time system monitoring tool.

The discrepancy between actual measured system flows (with Stuart-Atlanta out of service) and the MISO model (which assumed Stuart-Atlanta was in service) was still preventing the state estimator from solving correctly at 15:09 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, when the MISO reliability coordinator called PJM to verify the correct status. After the reliability coordinators determined that Stuart-Atlanta had tripped, MISO updated the state estimator and it solved correctly. The real-time contingency analysis was then run manually and solved successfully at 15:41. MISO's state estimator and contingency analysis were back under full automatic operation and solving effectively by 16:04, about two minutes before the trip of the Sammis-Star line and initiation of the cascade.

In summary, the MISO state estimator and real-time contingency analysis tools were effectively out of service between 12:15 and 15:41 and were not in full automatic operation until 16:04. This prevented MISO from promptly performing pre-contingency "early warning" assessments of power system reliability during the afternoon of August 14. MISO's ineffective diagnostic support contributed to FE's lack of situational awareness.

E. Precipitating Events: 345-kV Transmission Line Trips: 15:05 to 15:41 EDT

1. Summary

From 15:05:41 to 15:41:35, three 345-kV lines failed with power flows at or below each transmission line's emergency rating. Each trip and lockout was the result of a contact between an energized line and a tree that had grown so tall that it had encroached into the minimum safe clearance for the line. As each line failed, power flow was shifted onto the remaining lines. As each of the transmission lines failed and power flows shifted to other transmission paths, voltages on the rest of FE system degraded further. The following key events occurred during this period:

- 15:05:41: The Chamberlin-Harding 345-kV line tripped, reclosed, tripped again, and locked out.
- 15:31–33: MISO called PJM to determine if PJM had seen the Stuart-Atlanta 345-kV line outage. PJM confirmed Stuart-Atlanta was out.
- 15:32:03: The Hanna-Juniper 345-kV line tripped, reclosed, tripped again, and locked out.
- 15:35: 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.
- 15:36: MISO called FE regarding a post-contingency overload on the 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. MISO used the FMT to arrive at this assessment.
- 15:41:33–35: The Star-South Canton 345-kV line tripped, reclosed, tripped again at 15:41, and remained out of service, while AEP and PJM were discussing TLR relief options to reduce loading on the line.

2. Chamberlin-Harding 345-kV Line Trip at 15:05 EDT

Figure III.3 shows the location of the Chamberlin-Harding line and the two subsequent critical line trips.

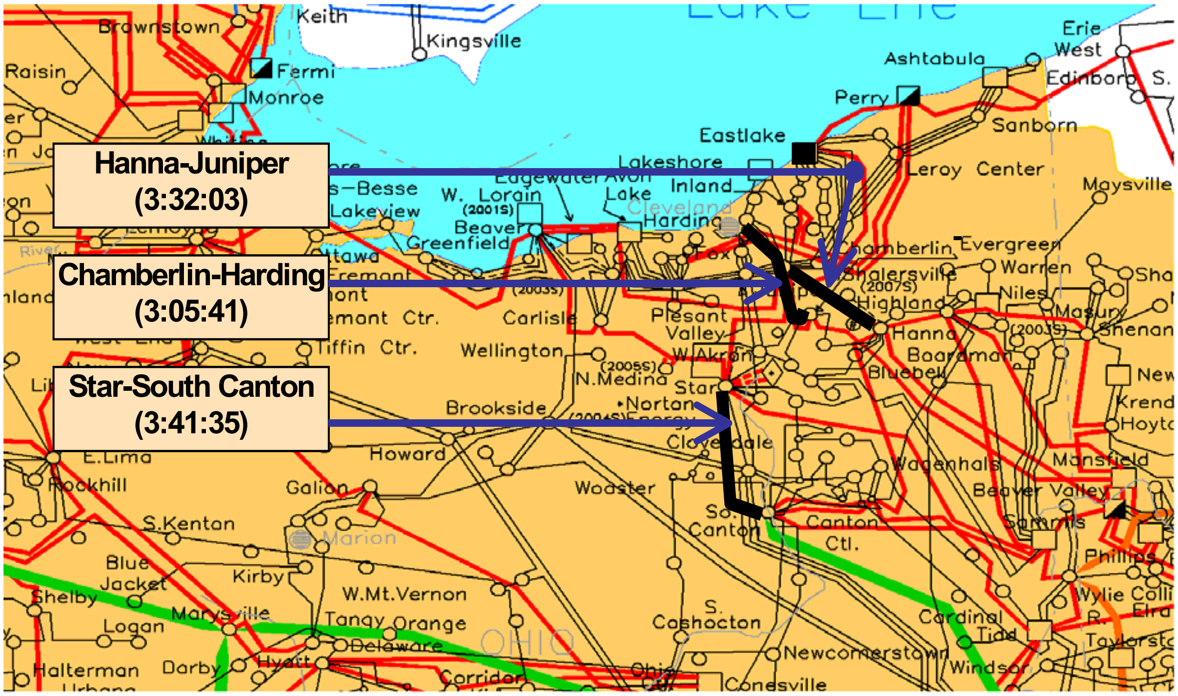
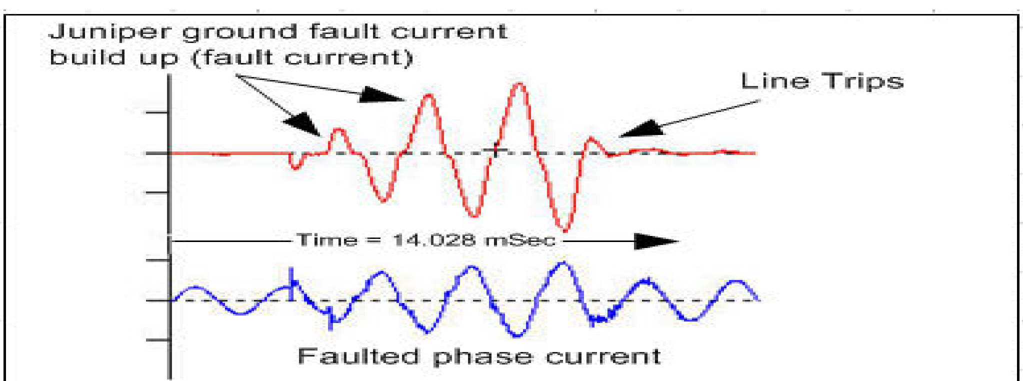


Figure III.3 — Location of Three Line Trips

At 15:05:41, The FE Chamberlin-Harding 345-kV line tripped and locked out while loaded at 500 MVA or 43.5 percent of its normal and emergency ratings of 1,195 MVA (which are the same values). At 43.5 percent loading, the conductor temperature did not exceed its design temperature and the line could not have sagged sufficiently to allow investigators to conclude that the line sagged into the tree due to overload. Instead, investigators determined that FE had allowed trees in the Chamberlin-Harding right-of-way to grow too tall and encroach into the minimum safe clearance from a 345-kV energized conductor. The investigation team examined the relay data for this trip, which indicated high impedance Phase C fault-to-ground, and identified the geographic location of the fault. They determined that the relay data match the classic signature pattern for a tree-to-line fault (Figure III.4). Chamberlin-Harding tripped on directional ground relay — part of a directional comparison relay scheme protecting the line.



Harding-Chamberlin 345-kV fault at 15:05 EDT
DFR recorder taken from Harding-Juniper at Juniper

Figure III.4 — Juniper DFR Indication of Tree Contact for Loss of the Chamberlin-Harding Line

Cause 2: FE did not effectively manage vegetation in its transmission line rights-of-way. The lack of situational awareness resulting from Causes 1a–1e would have allowed a number of system failure modes to go undetected. However, it was the fact that FE allowed trees growing in its 345-kV transmission rights-of-way to encroach within the minimum safe clearances from energized conductors that caused the Chamberlin-Harding, Hanna-Juniper, and Star-South Canton 345-kV line outages. These three tree-related outages triggered the localized cascade of the Cleveland-Akron 138-kV system and the over-loading and tripping of the Sammis-Star line, eventually snowballing into an uncontrolled wide-area cascade. These three lines experienced non-random, common mode failures due to un-checked tree growth. With properly cleared rights-of-way and calm weather, such as existed in Ohio on August 14, the chances of those three lines randomly tripping within 30 minutes is extremely small. Effective vegetation management practices would have avoided this particular sequence of line outages that triggered the blackout. However, effective vegetation management might not have precluded other latent failure modes. For example, investigators determined that there was an elevated risk of a voltage collapse in the Cleveland-Akron area on August 14 if the Perry 1 nuclear plant had tripped that afternoon in addition to Eastlake 5, because the transmission system in the Cleveland-Akron area was being operated with low bus voltages and insufficient reactive power margins to remain stable following the loss of Perry 1.

Going to the fault location as determined from the relay data, the field team found the remains of trees and brush. At this location, conductor height measured 46 feet 7 inches, while the height of the felled tree measured 42 feet; 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 three to four feet higher than estimated here. Burn marks were observed 35 feet 8 inches up the tree, and the crown of this tree was at least six feet taller than the observed burn marks. The tree showed evidence of fault current damage.

To be sure that the evidence of tree-to-line contacts and tree remains found at each site were 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 evidence of line-tree contacts. Records establish that there were no prior sustained outages known to be caused by trees for these lines in 2001, 2002, or 2003. Chamberlin-Harding had zero outages for those years. Hanna-Juniper had six outages in 2001, ranging from four minutes to a maximum of 34 minutes — two were from an unknown cause, one was caused by lightning, and three were caused by a relay failure or mis-operation. Star-South Canton had no outages in that same two-and-a-half year period.

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 flyovers in 2001 and 2002 indicate that the examiners saw a significant number of trees and brush that needed clearing or trimming along many FE transmission lines.

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

Chamberlin-Harding 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 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 Chamberlin-Harding trip as a significant event and could not advise FE regarding the event or its consequences.

Further, without its state estimator and associated real-time contingency analysis, MISO was unable to identify potential overloads that would occur due to various line or equipment outages. Accordingly, when the Chamberlin-Harding 345-kV line tripped at 15:05, the state estimator did not produce results and could not predict an overload if the Hanna-Juniper 345-kV line were also to fail.

MISO did not discover that Chamberlin-Harding 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, when MISO told FE that MISO's flowgate monitoring tool showed a Star-Juniper line overload following a contingency loss of Hanna-Juniper. However, investigators found no evidence within the control room logs or transcripts to show that FE knew of the Chamberlin-Harding line failure until after the blackout.

Cause 1e: FE did not have an effective contingency analysis capability cycling periodically on-line and did not have a practice of running contingency analysis manually as an effective alternative for identifying contingency limit violations. Real-time contingency analysis, cycling automatically every 5–15 minutes, would have alerted the FE operators to degraded system conditions following the loss of the Eastlake 5 generating unit and the Chamberlin-Harding 345-kV line. Initiating a manual contingency analysis after the trip of the Chamberlin-Harding line could also have identified the degraded system conditions for the FE operators. Know-ledge of a contingency limit violation after the loss of Chamberlin-Harding and know-ledge that conditions continued to worsen with the subsequent line losses would have allowed the FE operators to take corrective actions and notify MISO and neighboring systems of the developing system emergency. FE was operating after the trip of the Chamberlin-Harding 345-kV line at 15:05, such that the loss of the Perry 1 nuclear unit would have caused one or more lines to exceed their emergency ratings.

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

3. FE Hanna-Juniper 345-kV Line Trips at 15:32 EDT

Incremental line current and temperature increases, escalated by the loss of Chamberlin-Harding, caused enough sag on the Hanna-Juniper line that it experienced a fault current due to tree contact, tripped and locked out at 15:32:03, with current flow at 2,050 amperes or 87.5 percent of its normal and emergency line rating of 2,344 amperes. Figure III.5 shows the Juniper digital fault recorder indicating the tree signature of a high-impedance ground fault. Analysis showed high arc resistance limiting the actual fault current well below the calculated fault current assuming a "bolted" (no arc resistance) fault.

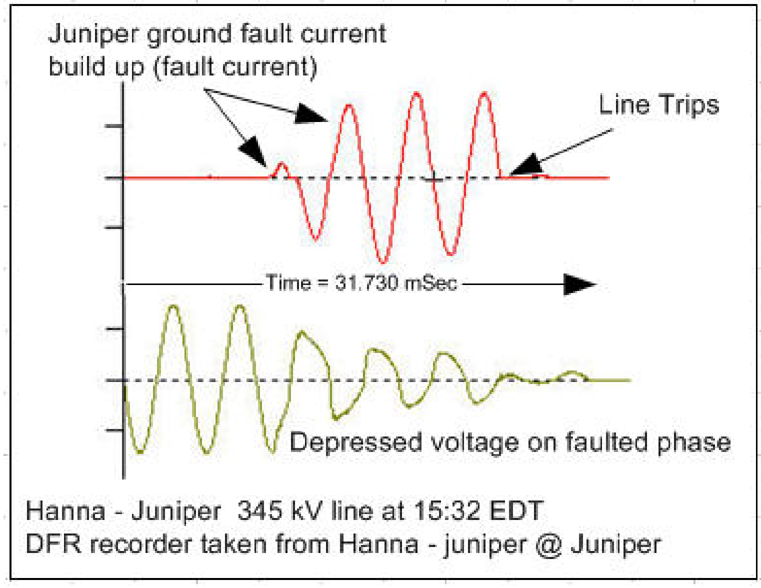


Figure III.5 — Juniper DFR Indication of Tree Contact for Loss of Hanna-Juniper

The tree contact occurred on the south phase of the Hanna-Juniper line, which is lower than the center phase due to construction design. Although little evidence remained of the tree during the field visit in October, the team observed a tree stump 14 inches in diameter at its ground line and talked to a member of the FE tree-trimming crew who witnessed the contact on August 14 and reported it to the FE operators. FE was conducting right-of-way vegetation maintenance and the tree crew at Hanna-Juniper was three spans away clearing vegetation near the line, when the contact occurred on August 14. FE provided photographs that clearly indicate that the tree was of excessive height. Similar trees nearby but not in the right-of-way were 18 inches in diameter at ground line and 60 feet in height. Further inspection showed at least 20 trees growing in this right-of-way.

When the Hanna-Juniper line tripped at 15:32:03, the Harding-Juniper 345-kV line tripped concurrently. Investigators believe the Harding-Juniper operation was an overtrip caused by a damaged coaxial cable that prevented the transmission of a blocking signal from the Juniper end of the line. Then the Harding-Juniper line automatically initiated a high-speed reclosure of both ring bus breakers at Juniper and one ring bus breaker at Harding. The A-Phase pole on the Harding breaker failed to reclose. This caused unbalanced current to flow in the system until the second Harding breaker reclosed automatically 7.5 seconds later.

Hanna-Juniper was loaded at 87.5 percent of its normal and emergency rating when it tripped. With this line open, almost 1,200 MVA had to find a new path to reach the loads in Cleveland. Loading on the remaining two 345-kV lines increased, with Star-Juniper taking the most of the power shift. This caused the loading on Star-South Canton to rise above 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.

Because its alarm system was not working, FE was not aware of the Chamberlin-Harding or Hanna-Juniper line trips. However, once MISO manually updated the state estimator model for the Stuart-Atlanta line outage, the software successfully completed a state estimation and contingency analysis at 15:41. But this left a 36-minute period, from 15:05 to 15:41, during which MISO did not anticipate the potential consequences of the Hanna-Juniper loss, and FE operators knew of neither 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 Chamberlin-Harding outage.

According to interviews, AEP had a contingency analysis capability that covered lines into Star. The AEP operator identified a problem for Star-South Canton overloads for a Sammis-Star line loss at about 15:33 and, at 15:35, asked PJM to begin developing a 350 MW TLR to mitigate it. The TLR was to relieve the actual overload above the normal rating then occurring on Star-South Canton, and to prevent an overload above the emergency rating on that line for the loss of Sammis-Star. But when they began working on the TLR, neither AEP nor PJM realized that Hanna-Juniper had already tripped at 15:32, further degrading system conditions. Most TLRs are for cuts of 25 to 50 MW. A 350 MW TLR request was highly unusual and the operators were attempting to confirm why so much relief was suddenly required before implementing the requested TLR.

Cause 3b: MISO did not have real-time topology information for critical lines mapped into its state estimator. The MISO state estimator and network analysis tools were still considered to be in development on August 14 and were not fully capable of automatically recognizing changes in the configuration of the modeled system. Following the trip of lines in the Cinergy system at 12:12 and the DP&L Stuart-Atlanta line at 14:02, the MISO state estimator failed to solve correctly as a result of large numerical mismatches. MISO real-time contingency analysis, which operates only if the state estimator solves, did not operate properly in automatic mode again until after the black-out. Without real-time contingency analysis information, the MISO operators did not detect that the FE system was in a contingency violation after the Chamberlin-Harding 345-kV line tripped at 15:05. Since MISO was not aware of the contingency violation, MISO did not inform FE and thus FE's lack of situational awareness described in Causes 1a-e was allowed to continue. With an operational state estimator and real-time contingency analysis, MISO operators would have known of the contingency violation and could have informed FE, thus enabling FE and MISO to take timely actions to return the system to within limits.

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. This shortened time span between the Hanna-Juniper and Star-South Canton line trips is a first hint that the pace of events was beginning to accelerate. This activity between AEP and PJM was the second time on August 14 an attempt was made to remove actual and contingency overloads using an administrative congestion management procedure (reallocation of transmission through TLR) rather than directly ordering generator shifts to relieve system overloads first. The prior incident was the TLR activity between Cinergy and MISO for overloads on the Cinergy system.

The primary means MISO was using to assess reliability on key flowgates was its flowgate monitoring tool. After the Chamberlin-Harding 345-kV line outage at 15:05, the FMT produced incorrect results because the outage was not reflected in the model. As a result, the tool assumed that Chamberlin-Harding was still available and did not predict an overload for the loss of the Hanna-Juniper 345-kV line.

When Hanna-Juniper tripped at 15:32, the resulting overload was detected by MISO SCADA and set off alarms to MISO's system operators, who then phoned FE about it. Because both MISO's state estimator was still in a developmental state, was not working properly, and the flowgate monitoring tool did not have updated line status information, MISO's ability to recognize evolving contingency situations on the FE system was impaired.

Although an inaccuracy was identified with MISO's flowgate monitoring tool, it still functioned with reasonable accuracy and prompted MISO to call FE to discuss the Hanna-Juniper line problem. The FMT showed an overload at 108 percent of the operating limit. However, the tool did not recognize that Chamberlin-Harding was out of service at the time. If the distribution factors had been updated, the overload would have appeared to be even greater. It would not have identified problems south of Star since that was not part of the flowgate and thus was not modeled in MISO's flowgate monitor.

4. Loss of the Star-South Canton 345-kV Line at 15:41 EDT

The Star-South Canton line crosses the boundary between FE and AEP; each company owns the portion of the line within its service territory and manages the right-of-way for that portion. The Star-South Canton line tripped and reclosed three times on the afternoon of August 14, first at 14:27:15 while operating at less than 55 percent of its rating. With the loss of Chamberlin-Harding and Hanna-Juniper, there was a substantial increase in load on the Star-South Canton line. This line, which had relayed and reclosed earlier in the afternoon at 14:27, again relayed and reclosed at 15:38:47. It later relayed and locked out in a two-second sequence from 15:41:33 to 15:41:35 on a Phase C ground fault. Subsequent investigation found substantial evidence of tree contact. It should be noted that this fault did not have the typical signature of a high impedance ground fault.

Following the first trip of the Star-South Canton line at 14:27, AEP called FE at 14:32 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 and that the South Canton breakers had reclosed successfully.

There was an internal FE conversation about the AEP call at 14:51 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. According to the transcripts, FE operators dismissed the information as either not accurate or not relevant to their system, without following up on the discrepancy between the AEP event and the information observed in the FE control room. There was no subsequent verification of conditions with MISO. Missing the trip and reclose of the Star-South Canton at 14:27, despite a call from AEP inquiring about it, was a clear indication that the FE operators' loss of situational awareness had begun.

At 15:19, AEP called FE back to confirm that the Star-South Canton trip had occurred and that an AEP technician had confirmed the relay operation at South Canton. The FE operator restated that because they had received no trouble alarms, they saw no problem. At 15:20, AEP decided to treat the South Canton digital fault recorder and relay target information as a spurious relay operation and to check the carrier relays to determine what the problem might be.

A second trip and reclose of Star-South Canton occurred at 15:38:48. Finally, at 15:41:35, the line tripped and locked out at the Star substation. A short-circuit-to-ground occurred in each case. Less than ten minutes after the Hanna-Juniper line trip at 15:32, Star-South Canton tripped with power flow at 93.2 percent of its emergency rating. AEP had called FE three times between the initial trip at 14:27 and 15:45 to determine if FE knew the cause of the line trips.

Investigators inspected the right-of-way at the location indicated by the relay digital fault recorders, which was 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. The identifiable tree remains measured 30 feet 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. Topsoil in the area of the tree trunk was also 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.

It was only after AEP notified FE that the Star-South Canton 345-kV circuit had tripped and locked out at 15:42 did the FE control area operator compare this information to the breaker statuses for their end of the line at Star. After 15:42, the FE operator failed to immediately inform the MISO and adjacent control areas when they became aware that system conditions had changed due to unscheduled equipment outages that might affect other control areas.

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

5. Degrading System Conditions After the 345-kV Line Trips

Figure III.6 shows the line loadings calculated by the investigation team 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, the graph tracks how the loading on each line increased as each subsequent 345-kV and 138-kV line tripped out of service between 15:05 (Chamberlin-Harding) and 16:06 (Dale-West Canton). As the graph shows, none of the 345- or 138-kV lines exceeded their normal ratings on an actual basis (although contingency overloads existed) until after the combined trips of Chamberlin-Harding and Hanna-Juniper. But immediately after Hanna-Juniper was lost, Star-South Canton's loading jumped from an estimated 82 percent of normal to 120 percent of normal (still below its emergency rating) and remained at that level for ten minutes before tripping out. To the right, the graph shows the effects of the 138-kV line failures (discussed next) on the remaining 345-kV line, i.e., Sammis-Star's loading increased steadily above 100 percent with each succeeding 138-kV line lost.

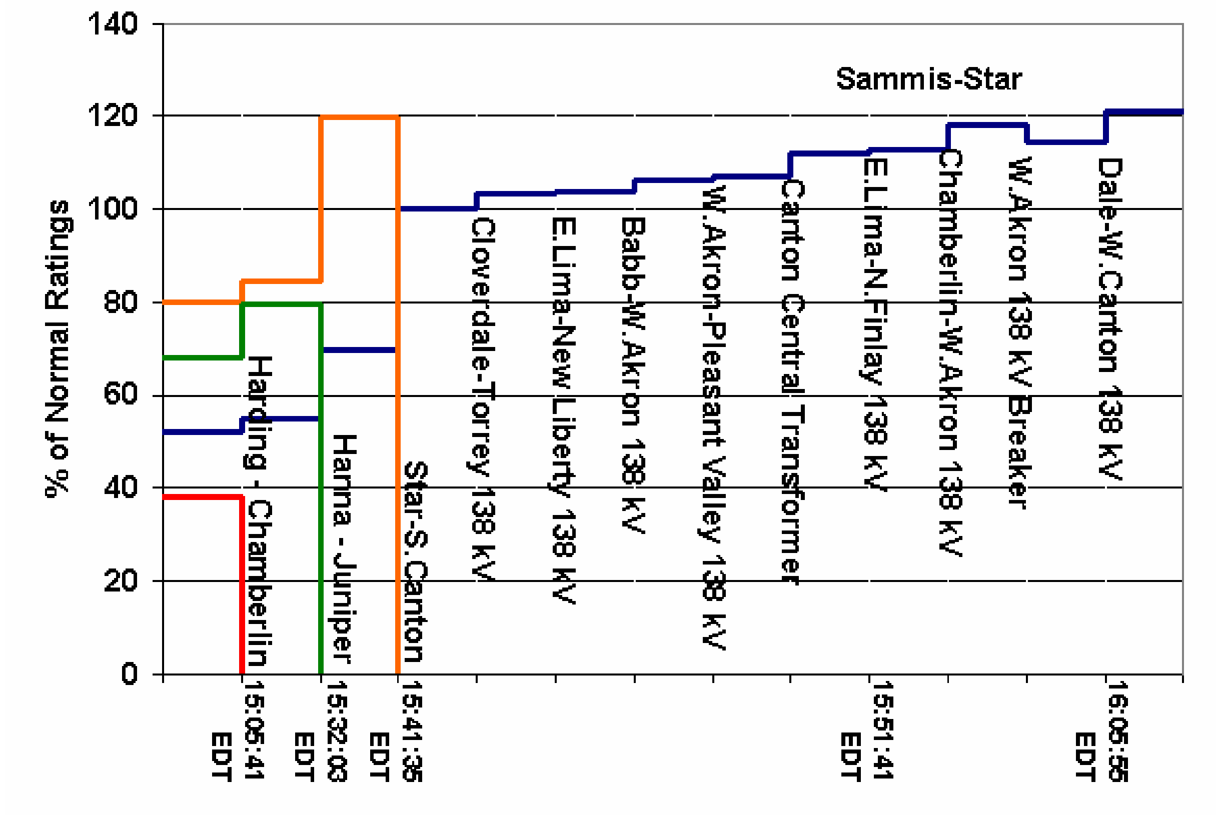


Figure III.6 — Line Loadings as the Northeast Ohio 345-kV Lines Trip

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

- The Star-Juniper 345-kV line, whose loading would exceed its emergency limit for the loss of the Hanna-Juniper 345-kV line; and
- The Hanna-Juniper and Harding-Juniper 345-kV lines, whose loadings would exceed emergency limits for the loss of the 1,255 MW Perry Nuclear Generating Plant.

Operationally, once the FE system entered an n-1 contingency violation state at 15:05 after the loss of Chamberlin-Harding, any facility loss beyond that pushed them into a more unreliable state. To restore the system to a reliable operating state, FE needed to reduce loading on the Star-Juniper, Hanna-Juniper, and Harding-Juniper lines (normally within 30 minutes) such that no single contingency would violate an emergency limit on one of those lines. Due to the non-random nature of events that afternoon (overgrown trees contacting lines), not even a 30-minute response time was adequate as events were beginning to speed up. The Hanna-Juniper line tripped and locked out at 15:32, only 27 minutes after Chamberlin-Harding.

6. Phone Calls Indicated Worsening Conditions

During the afternoon of August 14, FE operators talked to their field personnel, MISO, PJM, adjoining systems (such as AEP), and customers. The FE operators received pertinent information from all of these sources, but did not grasp some key information about the condition of the system from the clues offered. This information included a call from the FE eastern control center asking about possible line trips, a call from the Perry nuclear plant regarding what looked like near-line trips, AEP calling about their end of the Star-South Canton line tripping, and MISO and PJM calling about possible line overloads.

At 15:35, 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; a dispatcher called reporting a "bump" on their system. Soon after this call, the FE Reading, Pennsylvania, control center called reporting that fault recorders in the Erie west and south areas had activated, and 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."

It was at about this time that the FE operators began to suspect something might be wrong, but did not recognize that the problems were on their own system. "It's got to be in distribution, or something like that, or somebody else's problem … but I'm not showing anything." Unlike many transmission system control centers, the FE center did not have a map board, which might have shown the location of significant line and facility outages within the control area.

At 15:36, MISO contacted FE regarding the post-contingency overload on Star-Juniper for the loss of the Hanna-Juniper 345-kV line. Unknown to MISO and FE, Hanna-Juniper had already tripped four minutes earlier.

At 15:42, the FE western transmission operator informed the FE computer support staff that the EMS system functionality was compromised. "Nothing seems to be updating on the computers…. We've had people calling and reporting trips and nothing seems to be updating in the event summary… I think we've got something seriously sick." This is the first evidence that a member of the FE control room operating staff recognized that their EMS system was degraded. There is no indication that he informed any of the other operators at this time. However, the FE computer support staff discussed the subsequent EMS corrective action with some control room operators shortly thereafter.

Also at 15:42, 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."

At 15:45, the tree trimming crew reported that they had witnessed a tree-caused fault on the Eastlake-Juniper line. However, the actual fault was on the Hanna-Juniper 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.

After the Star-South Canton line tripped a third time and locked out at 15:42, AEP called FE at 15:45 to discuss and inform them that they had additional lines showing overloads. FE recognized then that the Star breakers had tripped and remained open.

At 15:46, 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."

At 15:48, an FE transmission operator sent staff to man the Star substation, and then at 15:50, requested staffing at the regions, beginning with Beaver, then East Springfield. This act, 43 minutes after the Chamberlin-Harding line trip and 18 minutes before the Sammis-Star trip, signaled the start of the cascade, and was the first clear indication that at least one of the FE system operating staff was beginning to recognize that an emergency situation existed.

At the same time the activities above were unfolding at FE, AEP operators grew quite concerned about the events unfolding on their ties with FE. Beginning with the first trip of the Star-South Canton 345 kV line, AEP contacted FE attempting to verify the trip. Later, their state estimation and contingency analysis tools indicated a contingency overload for Star-South Canton 345 kV line and AEP requested Transmission Loading Relief action by their reliability coordinator, PJM. A conversation beginning at 15:35 between AEP and PJM showed considerable confusion on the part of the reliability coordinator.

Cause 3c: The PJM and MISO reliability coordinators lacked an effective procedure on when and how to coordinate an operating limit violation observed by one of them in the other's area due to a contingency near their common boundary. The lack of such a procedure caused in-effective communications between PJM and MISO regarding PJM's awareness of a possible overload on the Sammis-Star line as early as 15:48. An effective procedure would have enabled PJM to more clearly communicate the information it had regarding limit violations on the FE system, and would have enabled MISO to be aware of those conditions and initiate corrective actions with FE.

PJM Operator: "Where specifically are you interested in?"

AEP Operator: "The South Canton-Star."

PJM Operator: "The South Canton-Star. Oh, you know what? This is interesting. I believe this one is ours…that one was actually in limbo one night, one time we needed it."

AEP Operator: "For AEP?"

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

AEP Operator: "Yeah."

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

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

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

AEP Operator: "Pardon?"

PJM Operator: "What do you need? What do you need on it? How much relief you need?"

AEP Operator: "Quite a bit."

PJM Operator: "Quite a bit. What's our limit?"

AEP Operator: "I want a 3-B."

PJM Operator: "3-B."

AEP Operator: "It's good for 1,412, so I need how much cut off?"

PJM Operator: "You need like… 230, 240."

PJM Operator: "Now let me ask you, there is a 345 line locked out DPL Stuart to Atlanta. Now, I still haven't had a chance to get up and go see where that is. Now, I don't know if that would have an effect."

AEP Operator: "1,341. I need - man, I need 300. I need 300 megawatts cut."

PJM Operator: "Okay. Verify our real-time flows on…"

From this conversation it appears that the PJM reliability coordinator is not closely monitoring Dayton Power and Light and AEP facilities (areas for which PJM has reliability coordinator responsibility) in real time. Further, the operator must leave the desk to determine where a 345 kV line is within the system, indicating a lack of familiarity with the system.

AEP Operator: "What do you have on the Sammis-Star, do you know?"

PJM Operator: I'm sorry? Sammis-Star, okay, I'm showing 960 on it and it's highlighted in blue. Tell me what that means on your machine."

AEP Operator: "Blue? Normal. Well, it's going to be in blue, I mean - that's what's on it?"

PJM Operator: "960, that's what it says."

AEP Operator: "That circuit just tripped. South Canton-Star."

PJM Operator: "Did it?"

AEP Operator: "It tripped and re-closed…"

AEP Operator: "We need to get down there now so they can cut the top of the hour. Is there anything on it? What's the flowgate, do you know?"

PJM Operator: "Yeah, I got it in front of me. It is-it is 2935."

AEP Operator: "Yeah…2935. I need 350 cut on that."

PJM Operator: "Whew, man."

AEP Operator: "Well, I don't know why. It popped up all of a sudden like that…that thing just popped up so fast."

PJM Operator: "And… 1,196 on South Canton. Can you verify these? And 960 on - South Canton-Star 1,196, Sammis-Star 960?"

AEP Operator: "They might be right, I'm…"

PJM Operator: "They were highlighted in blue, I guess I thought maybe that was supposed to be telling me something."

This conversation demonstrates that the PJM operator is not fully familiar with the monitoring system being used. The operator is questioning the AEP operator about what something in blue on the screen represents since presumably the AEP operator is more familiar with the system the PJM operator is using.

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

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

AEP Operator: "Probably."

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

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

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

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

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

AEP: "Oh, my gosh, I'm in deep…"

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

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

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

AEP Operator: "Pardon?"

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

As the AEP operators continue to witness the evolving cascade of the FE 138 kV system, the conversation ended at this point and PJM called MISO at 15:55. PJM reported the Star-South Canton trip to MISO, but their measures of the resulting line flows on the FE Sammis-Star line did not match, causing them to wonder whether the Star-South Canton line had returned to service. From the MISO operator phone transcripts:

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

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

PJM Operator: "Did they?"

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

PJM Operator: "Star-Juniper."

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

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

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

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

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

PJM Operator: "Yes."

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

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

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

PJM Operator: "1,109?"

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

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

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

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

MISO Operator: "Okay."

PJM Operator: "Thank you, sir. Bye."

Considering the number of facilities lost, and that each reliability coordinator is discovering new lines are out that he did not previously know, there is an eerie lack of urgency or any discussion of actions to be taken. The MISO operator provided some additional information about transmission line outages in FE, even though they did not have direct monitoring capabilities of their facilities on August 14. The PJM operator indicated that the South Canton-Star line was out of service, but did not relay any of the information regarding the other lines that were reported as tripping by the AEP operator. The MISO operator did not act on this information and PJM operator did not press the issue.

As shown by the investigation, by 15:55 at the start of this PJM-MISO call, the overload on Sammis-Star line exceeded 110% and continued to worsen. The overload began at 15:42 after the Star - S. Canton 345kV line locked open. At 16:05:57 just prior to tripping, fault recorders show a Sammis-Star flow of 2,850 amperes or 130% of its emergency 2193 ampere rating.

At 15:56, PJM was still concerned about the impact of the Star-South Canton trip, and PJM called FE to report that Star-South Canton had tripped and that PJM thought Sammis-Star was in actual emergency limit overload. FE could not confirm this overload. Investigators later discovered that FE was using a higher rating for the Sammis-Star line than was being used by MISO, AEP, and PJM — indicating ineffective coordination of FE line ratings with others.[4] FE informed PJM that Hanna-Juniper was also out of service. At this time, FE operators still believed that the problems existed beyond their system, one of them saying, “AEP must have lost some major stuff.”

Modeling indicates that the return of either the Hanna-Juniper or Chamberlin-Harding lines would have diminished, but not alleviated, all of the 138-kV overloads. The return of both lines would have restored all of the 138 lines to within their emergency ratings. 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. Also, since Star-South Canton had already tripped and reclosed three times, it is 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 could have reduced most line loadings to within emergency range and helped to stabilize the system. However, the amount of load shedding required grew rapidly as the FE system unraveled.

F. Localized Cascade of the 138-kV System in Northeastern Ohio: 15:39 to 16:08 EDT

1. Summary

At 15:39, a series of 138-kV line trips occurred in the vicinity of Akron because the loss of the Chamberlin-Harding, Hanna-Juniper, and Star-South Canton 345-kV lines overloaded the 138-kV system with electricity flowing north toward the Akron and Cleveland loads. Voltages in the Akron area also began to decrease and eventually fell below low limits.

One of the two Pleasant Valley-West Akron lines was the first 138-kV line to trip at 15:39:37, indicating the start of a cascade of 138-kV line outages in that area. A total of seven 138-kV

[4] 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 950 MVA normal rating and 1,076 MVA emergency rating for this line. The facility owner (in this case FE) develops the line rating. It has not been determined when FE changed the ratings it was using; they did not communicate the changes to all concerned parties.

lines tripped during the next 20 minutes, followed at 15:59 by a stuck-breaker operation that cleared the 138-kV bus at West Akron and instantaneously opened five more 138-kV lines. Four additional 138-kV lines eventually opened over a three-minute period from 16:06 to 16:09, after the Sammis-Star 345-kV line opened to signal the transition from a localized failure to a spreading wide-area cascade.

During this same period at 15:45:41, the Canton Central-Tidd 345-kV line tripped and then reclosed at 15:46:29. The Canton Central 345/138-kV Circuit Breaker A1 operated multiple times, causing a low air pressure problem that inhibited circuit breaker tripping. This event forced the Canton Central 345/138-kV transformer to disconnect and remain out of service, further weakening the Canton-Akron area 138-kV transmission system.

Approximately 600 MW of customer loads were shut down in Akron and areas to the west and south of the city during the cascade because they were being served by transformers connected to those lines. As the lines failed, severe voltage drops caused a number of large industrial customers with voltage-sensitive equipment to go off-line automatically to protect their operations.

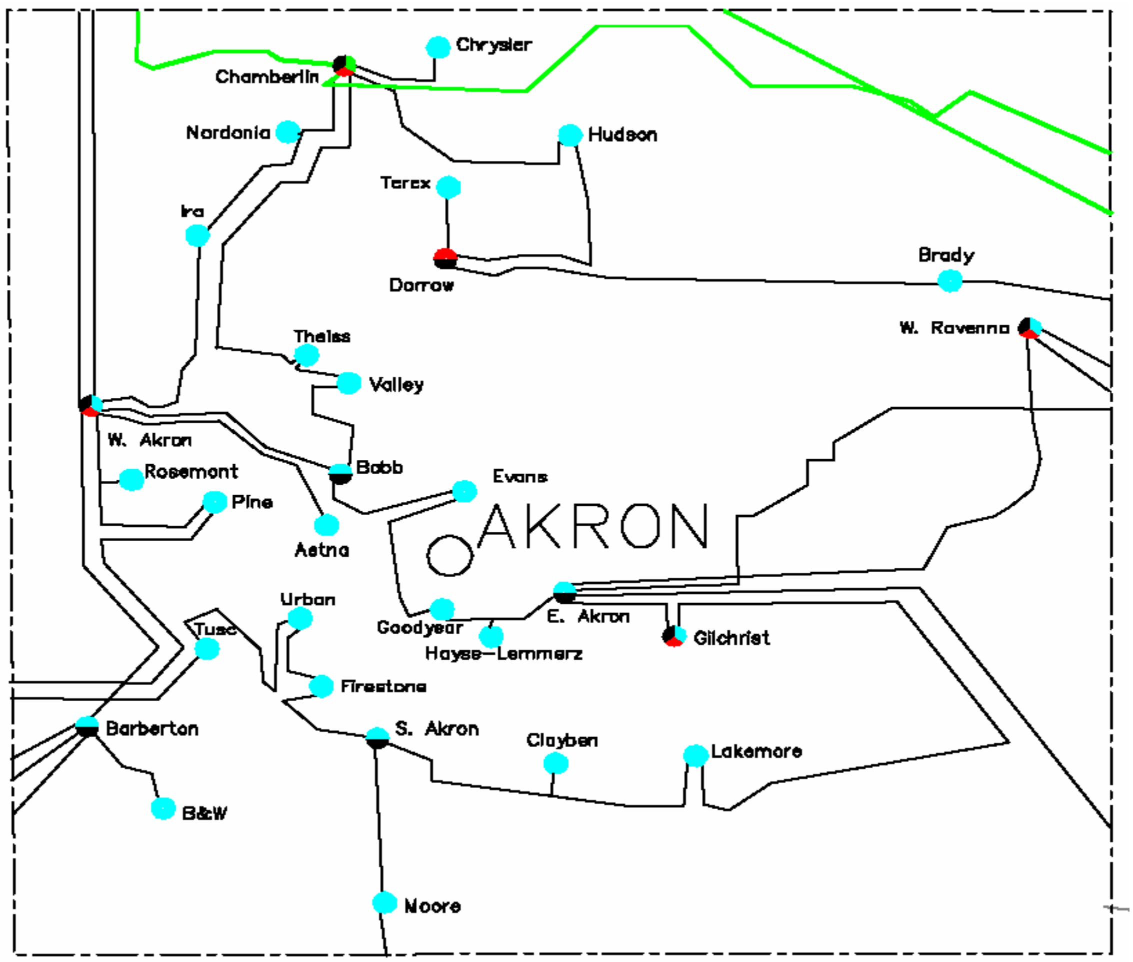


Figure III.7 — Akron Area Substations Participating in Localized 138-kV Cascade

2. 138-kV Localized Cascade Sequence of Events

From 15:39 to 15:58:47, seven 138-kV lines in northern Ohio tripped and locked out.

Table III.1 — 138-kV Line Trips Near Akron: 15:39 to 15:58:47

15:39:17	Pleasant Valley-West Akron 138-kV line tripped and reclosed at both ends.
15:42:05	Pleasant Valley-West Akron 138-kV West line tripped and reclosed.
15:44:40	Pleasant Valley-West Akron 138-kV West line tripped and locked out. B Phase had sagged into the underlying distribution conductors.
15:42:49	Canton Central-Cloverdale 138-kV line tripped and reclosed.
15:45:40	Canton Central-Cloverdale 138-kV line tripped and locked out. Phase-to-ground pilot relay targets were reported at both ends of the line. DFR analysis identified the fault to be 7.93 miles from Canton Central. The Canton Central 138-kV bus is a ring bus. A 138-kV circuit breaker failed to clear the 138-kV line fault at Canton Central. This breaker is common to the 138-kV autotransformer bus and the Canton Central-Cloverdale 138-kV line.
15:42:53	Cloverdale-Torrey 138-kV line tripped.
15:44:12	East Lima-New Liberty 138-kV line tripped. B Phase sagged into the underbuild.
15:44:32	Babb-West Akron 138-kV line tripped and locked out.
15:51:41	East Lima-North Findlay 138-kV line tripped and reclosed at the East Lima end only. At the same time, the Fostoria Central-North Findlay 138-kV line tripped and reclosed, but never locked out.
15:58:47	Chamberlin-West Akron 138-kV line tripped. Relays indicate a probable trip on overload.

With the Canton Central-Cloverdale 138-kV line trip at 15:45:40, the Canton Central 345-kV and 138-kV circuit breakers opened automatically to clear the fault via breaker failure relaying. Transfer trip initiated circuit breaker tripping at the Tidd substation end of the Canton Central-Tidd 345-kV line. A 345-kV disconnect opened automatically disconnecting two autotransformers from the Canton Central-Tidd 345-kV line after the fault was interrupted. The 138-kV circuit breaker's breaker-failure relay operated as designed to clear the fault. After the 345-kV disconnect opened and the 345-kV circuit breakers automatically reclosed, Canton Central-Tidd 345kV was restored at 15:46:29.

Table III.2 — West Akron Stuck Breaker Failure

15:59:00	West Akron-Aetna 138-kV line opened.
15:59:00	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.
15:59:00	West Akron-Granger-Stoney-Brunswick-West Medina opened.
15:59:00	West Akron-Pleasant Valley 138-kV East line (Q-22) opened.
15:59:00	West Akron-Rosemont-Pine-Wadsworth 138-kV line opened.

The West Akron substation 138-kV bus was cleared at 15:59:00 due to a circuit breaker failure. The circuit breaker supplied a 138/69-kV transformer. The transformer phase directional power relay operated to initiate the trip of the breaker and its subsequent breaker failure backup protection. There was no system fault at the time. The phase directional power relay operated because the 69-kV system in the Akron area became a supply to the 138-kV system. This reversal of power was due to the number of 138-kV lines that had tripped due to overloads and line faults caused by line overloads.

Investigators believe that the 138-kV circuit breaker failed because it was slow to operate. At 15:59:00, the West Akron 138-kV bus cleared from a failure to trip relay on the 138-kV circuit breaker B26, which supplies the 138/69-kV transformer number 1. The breaker trip was initiated by a phase directional overcurrent relay in the B26 relay circuit looking directionally into the 138-kV system from the 69-kV system. 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 number 1 was interrupted. Output of the failure to trip (breaker failure) timer initiated a trip of all five remaining 138-kV lines connected at West Akron. Investigators believe that the relay may have operated due to high reactive power flow into the 138-kV system. This is possible even though power was flowing into the 69-kV system at the time.

From 16:00 to 16:08:59, four additional 138-kV lines tripped and locked out, some before and some after the Sammis-Star 345-kV line trip. After the Cloverdale-Torrey line failed at 15:42, Dale-West Canton was the most heavily loaded line on the FE system. It held on, although overloaded to between 160 and 180 percent of its normal rating, until tripping at 16:05:55. The loss of the Dale-West Canton 138-kV line had a significant effect on the area, and voltages dropped significantly after the loss of this line.

Even more importantly, loss of the Dale-West Canton line shifted power from the 138-kV system back to the remaining 345-kV network, pushing Sammis-Star's loading above 120 percent of its rating. This rating is a substation equipment rating rather than a transmission line thermal rating, therefore sag was not an issue. Two seconds later, at 16:05:57, Sammis-Star tripped and locked out. Unlike the previous three 345-kV lines, which tripped on short circuits 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 problems in northeast Ohio initiated a cascading blackout across the Northeast.

Table III.3 — Additional 138-kV Line Trips Near Akron

16:05:55	Dale-West Canton 138- kV line tripped at both ends, reclosed at West Canton only.
16:05:57	Sammis-Star 345-kV line tripped.
16:06:02	Star-Urban 138-kV line tripped (reclosing is not initiated for backup trips).
16:06:09	Richland-Ridgeville-Napoleon-Stryker 138-kV line tripped and locked out at all terminals.
16:08:58	Ohio Central-Wooster 138-kV line tripped.
16:08:55	East Wooster-South Canton 138-kV line tripped, but successful automatic reclosing restored this line.

3. Sammis-Star 345-kV Line Trip: Pivot Point

Sammis-Star did not trip due to a short circuit to ground (as did the prior 345-kV lines that tripped). Sammis-Star tripped due to protective relay action that measured low apparent impedance (depressed voltage divided by abnormally high line current) (Figure III.10). There was no fault and no major power swing at the time of the trip — rather, high flows above the line's emergency rating, together with depressed voltages, caused the overload to appear to the protective relays as a remote fault on the system. In effect, the relay could no longer differentiate between a remote three-phase fault and a high line-load condition. Moreover, the reactive flows (Var) on the line were almost ten times higher than they had been earlier in the day. The steady state loading on the line had increased gradually to the point where the operating point entered the zone 3 relay trip circle. The relay operated as it was designed to do. By design, reclosing is not initiated for trips initiated by backup relays.

As shown in Figure III.8, the Sammis-Star line trip completely severed the 345-kV path into northern Ohio from southeast Ohio, triggering a new, fast-paced sequence of 345-kV transmission line trips in which each line trip placed a greater flow burden on those lines remaining in service. After Sammis-Star tripped, there were only three paths left for power to flow into northern Ohio: (1) from northwestern Pennsylvania to northern Ohio around the south shore of Lake Erie, (2) from southern Ohio, and (3) from eastern Michigan and Ontario. Northeastern Ohio had been substantially weakened as a source of power to eastern Michigan, making the Detroit area more reliant on 345-kV lines west and northwest of Detroit, and from northwestern Ohio to eastern Michigan.

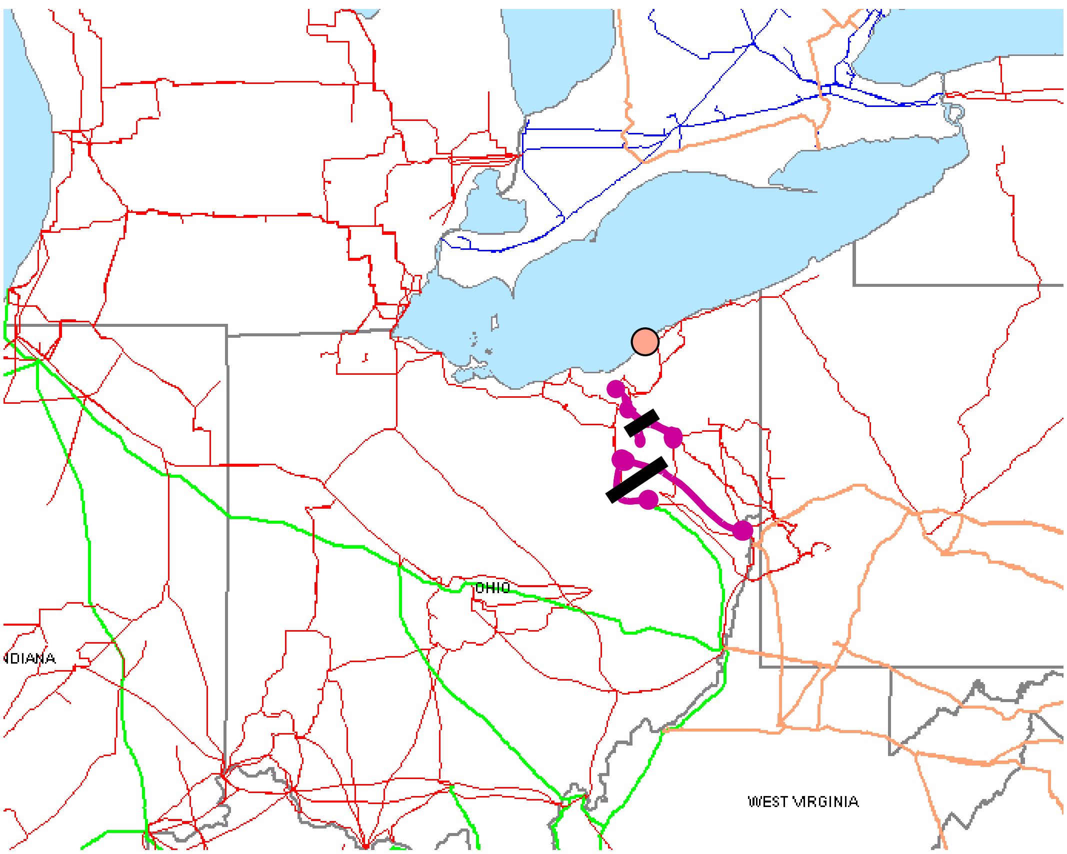


Figure III.8 — Cleveland-Akron Cut Off

After the Sammis-Star line trip, the conditions were set for an uncontrolled cascade of line failures that would separate the northeastern United States and eastern Canada from the rest of the Eastern Interconnection, then a breakup and collapse of much of that newly formed island. An important distinction is drawn here — that no events, actions, or failures to take action after the Sammis-Star trip can be deemed to have caused the blackout. Later sections will address other factors that affected the extent and severity of the blackout.

The Sammis-Star line tripped at Sammis Generating Station due to a zone 3 impedance relay. There were no system faults occurring at the time. The relay tripped because increased real and reactive power flow caused the apparent impedance to be within the impedance circle (reach) of the relay. Several 138-kV line outages just prior to the tripping of Sammis-Star contributed to the tripping of this line. Low voltages and the increased reactive power flow into the line from Sammis Generating Station contributed to the operation of the relay. Prior to the loss of Sammis-Star, operator action to shed load may have been an appropriate action. Subsequent to the Sammis-Star line trip, only automatic protection systems would have mitigated the cascade.

A zone 3 relay can be defined as an impedance relay that is set to detect system faults on the protected transmission line and beyond.[5] It sometimes serves a dual purpose. It can act through a timer to see faults beyond the next bus up to and including the furthest remote element attached to the bus. It is used for equipment protection beyond the line and it is an alternative to equipment failure communication systems sometimes referred to as breaker failure transfer trip. Zone 3 relays can also be used in the high-speed relaying system for the line. In this application, the relay needs directional intelligence from the other end of the line that it receives via a highly reliable communication system. In the Sammis-Star trip, the zone 3 relay operated because it was set to detect a remote fault on the 138-kV side of a Star substation transformer in the event of a breaker failure.

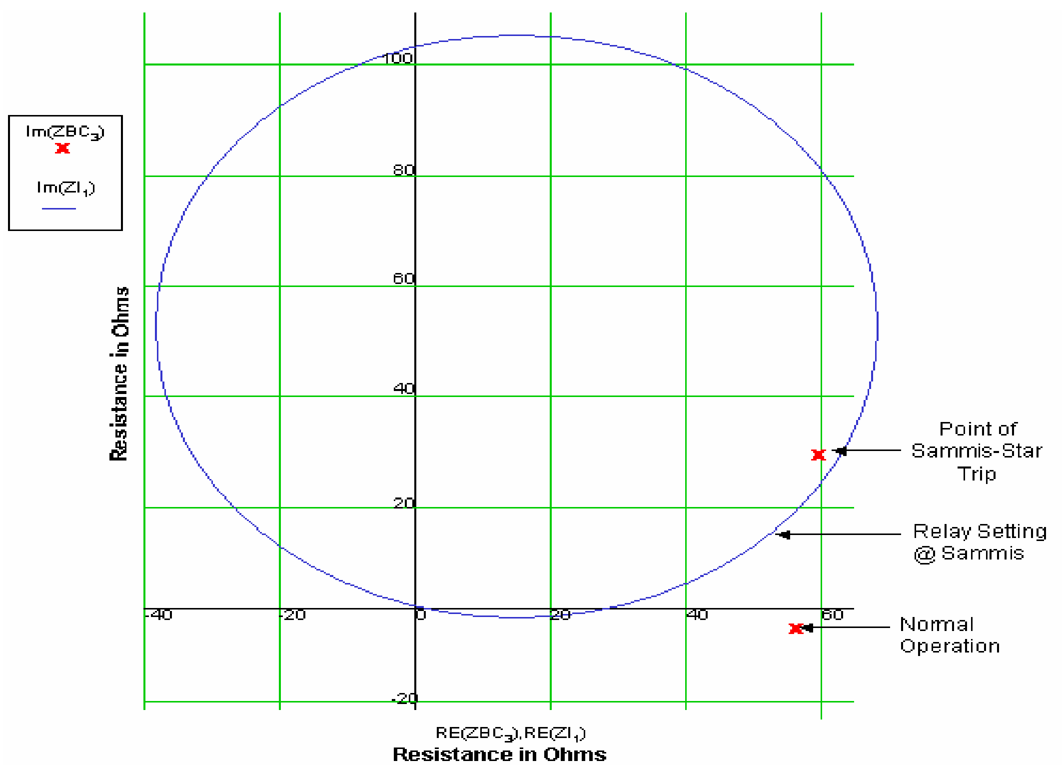


Figure III.9 — Load Encroachment of Sammis-Star Zone 3 Impedance Relay

[5] Zone 3 in this context means all forward and overreaching distance relays, which could also include zone 2 distance relays.

Systems Failure Anatomy of a Blackout Part 1
Updated on: 1/28/2013

1. The North American power grid experienced its largest blackout ever, on August 14, 2003. The blackout affected an estimated _________ people and more than 70,000 megawatts (MW) of electrical load in parts of Ohio, Michigan, New York, Pennsylvania, New Jersey, Connecticut, Massachusetts, Vermont, and the Canadian provinces of Ontario and Québec.

    a) 30 million
    b) 40 million
    c) 50 million
    d) 60 million

2. Immediately following the blackout, NERC assembled a team of technical experts from _________ to investigate exactly what happened, why it happened, and what could be done to minimize the chance of future outages.

    a) United States
    b) Canada
    c) Mexico
    d) both a) and b)

3. According to the November 19 interim report, the Task Force and NERC concluded that the initiating cause of the blackout was _________.

    a) that FirstEnergy lost functionality of its critical monitoring tools and as a result lacked situational awareness of degraded conditions on its transmission system
    b) that FirstEnergy did not adequately manage tree growth in its transmission rights-of-way
    c) that the Midwest Independent Systems Operator reliability coordinator did not provide adequate diagnostic support
    d) all of the above

4. FirstEnergy is the _________ largest electric utility in the United States and serves 4.4 million electric customers.

    a) third
    b) fifth
    c) seventh
    d) ninth

5. Using steady-state (power flow) analysis immediately prior to the tripping of the FE Chamberlin-Harding transmission line, the system was discovered to be operating _________ defined steady-state limits.

    a) within
    b) outside

6. The FE control area peak load on August 14 was also the peak load for the summer of 2003, although it was not the all-time peak recorded for that system.

    a) True
    b) False

7. Mary, a northeastern Ohio resident, noted that on August 14 temperatures were slightly high, comparable to that of a warm sunny day. Due to the increase in temperature, the demand for electricity in northeastern Ohio also increased. However, the increase in electrical demand was not a record-high and did not cause the blackout.

    a) True
    b) False

8. According to Table II.2, the "Actual Peak Load (MW)" of the month of August was _________ in 2002 than in August 2003.

    a) lower
    b) same
    c) higher

9. Unlike _________, which is the same at any point in time across the interconnection, _________ varies by location and operators must monitor voltages continuously at key locations across their systems.

    a) frequency; voltage
    b) current; frequency
    c) voltage; current
    d) current; frequency

10. Voltage measurements can be challenging on hot summer days, like August 14, because of _________.

    a) high transfers of power
    b) high air-conditioning requirements
    c) increase in need for reactive power
    d) all of the above

11. On the day of the blackout, the alarm and logging system in the FE control room failed and was not restored until after the blackout. Loss of this critical control center function was a key factor in the loss of situational awareness of system conditions by the FE operators.

    a) True
    b) False

12. The investigation found that the FE had provided system operators with the capability to manually and automatically shed that amount of load in the Cleveland area in a matter of minutes.

    a) True
    b) False

13. Due to the concurrent loss of two EMS servers, operator screen refresh rates were slowed from 1-3 seconds to as long as _________ per screen. This added to the lack of situation awareness during the blackout.

    a) 14 seconds
    b) 23 seconds
    c) 38 seconds
    d) 59 seconds

14. Loss of _________ meant that FE operators could not manage affiliated power plants on pre-set programs to respond automatically to meet FE system load and interchange obligations.

    a) situational awareness
    b) Automatic Generation Control (AGC)
    c) power
    d) alarm functionality

15. Without an effective EMS, one of the only remaining way to monitor system conditions would have been through _________.

    a) telephone calls
    b) email
    c) telegraph
    d) all of the above

16. Investigators determined that FE had allowed trees in the Chamberlin-Harding right-of-way to grow too tall and encroach into the minimum safe clearance from a _________ energized conductor.

    a) 145-kV
    b) 245-kV
    c) 345-kV
    d) 445-kV

17. Shown on Figure III.6 (Page 46) which of the following lines operated at 120% of its normal rating?

    a) Harding-Chamberlin
    b) Cloverdale-Torrey
    c) Hanna-Juniper
    d) Star-Canton

18. Approximately 600 MW of customer loads were shut down in Akron and areas to the west and south of the city during the cascade of lines tripping and then coming back on.

    a) 300 MW
    b) 600 MW
    c) 900 MW
    d) 1200 MW

19. Why did the Sammis-Star line trip?

    a) Short circuit
    b) High temperature
    c) Low resistance
    d) Impedance relay

20. Which line trip was the last event that occurred that could have caused the blackout?

    a) Sammis-Star
    b) Hanna-Juniper
    c) Harding Chamberlin
    d) Dale-Conton