4. Context and Preconditions for the Blackout: The Northeastern Power Grid Before the Blackout Began

Summary

This chapter reviews the state of the northeast portion of the Eastern Interconnection during the days and hours before 16:00 EDT on August 14, 2003, to determine whether grid conditions before the blackout were in some way unusual and might have contributed to the initiation of the blackout. Task Force investigators found that at 15:05 Eastern Daylight Time, immediately before the tripping (automatic shutdown) of FirstEnergy's (FE) Harding-Chamberlin 345-kV transmission line, the system was electrically secure and was able to withstand the occurrence of any one of more than 800 contingencies, including the loss of the Harding-Chamberlin line. At that time the system was electrically within prescribed limits and in compliance with NERC's operating policies.

Determining that the system was in a reliable operational state at 15:05 EDT on August 14, 2003, is extremely significant for determining the causes of the blackout. It means that none of the electrical conditions on the system before 15:05 EDT was a direct cause of the blackout. This eliminates a number of possible causes of the blackout, whether individually or in combination with one another, such as:

◆ Unavailability of individual generators or transmission lines

◆ High power flows across the region

◆ Low voltages earlier in the day or on prior days

◆ System frequency variations

◆ Low reactive power output from independent power producers (IPPs).

This chapter documents that although the system was electrically secure, there was clear experience and evidence that the Cleveland-Akron area was highly vulnerable to voltage instability problems. While it was possible to operate the system securely despite those vulnerabilities, FirstEnergy was not doing so because the company had not conducted the long-term and operational planning studies needed to understand those vulnerabilities and their operational implications.

It is important to emphasize that establishing whether conditions were normal or unusual prior to and on August 14 does not change the responsibilities and actions expected of the organizations and operators charged with ensuring power system reliability. As described in Chapter 2, the electricity industry has developed and codified a set of mutually reinforcing reliability standards and practices to ensure that system operators are prepared for the unexpected. The basic assumption underlying these standards and practices is that power system elements will fail or become unavailable in unpredictable ways and at

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Reliability and Security

NERC—and this report—use the following definitions for reliability, adequacy, and security.

Reliability: The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electricity supply.

Adequacy: The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security: The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

unpredictable times. Sound reliability management is designed to ensure that operators can continue to operate the system within appropriate thermal, voltage, and stability limits following the unexpected loss of any key element (such as a major generator or key transmission facility). These practices have been designed to maintain a functional and reliable grid, regardless of whether actual operating conditions are normal.

It is a basic principle of reliability management that "operators must operate the system they have in front of them"—unconditionally. The system must be operated at all times to withstand any single contingency and yet be ready within 30 minutes for the next contingency. If a facility is lost unexpectedly, the system operators must determine whether to make operational changes, including adjusting generator outputs, curtailing

Geography Lesson

In analyzing the August 14 blackout, it is crucial to understand the geography of the FirstEnergy area. FirstEnergy has seven subsidiary distribution utilities: Toledo Edison, Ohio Edison, and The Illuminating Company in Ohio and four more in Pennsylvania and New Jersey. Its Ohio control area spans the three Ohio distribution utility footprints and that of Cleveland Public Power, a municipal utility serving the city of Cleveland. Within FE's Ohio control area is the Cleveland-Akron area, shown in red cross-hatch.

This geographic distinction matters because the Cleveland-Akron area is a transmission-constrained load pocket with relatively limited generation. While some analyses of the blackout refer to voltages and other indicators measured at the boundaries of FE's Ohio control area, those indicators have limited relevance to the blackout—the indicators of conditions at the edges of and within the Cleveland-Akron area are the ones that matter.
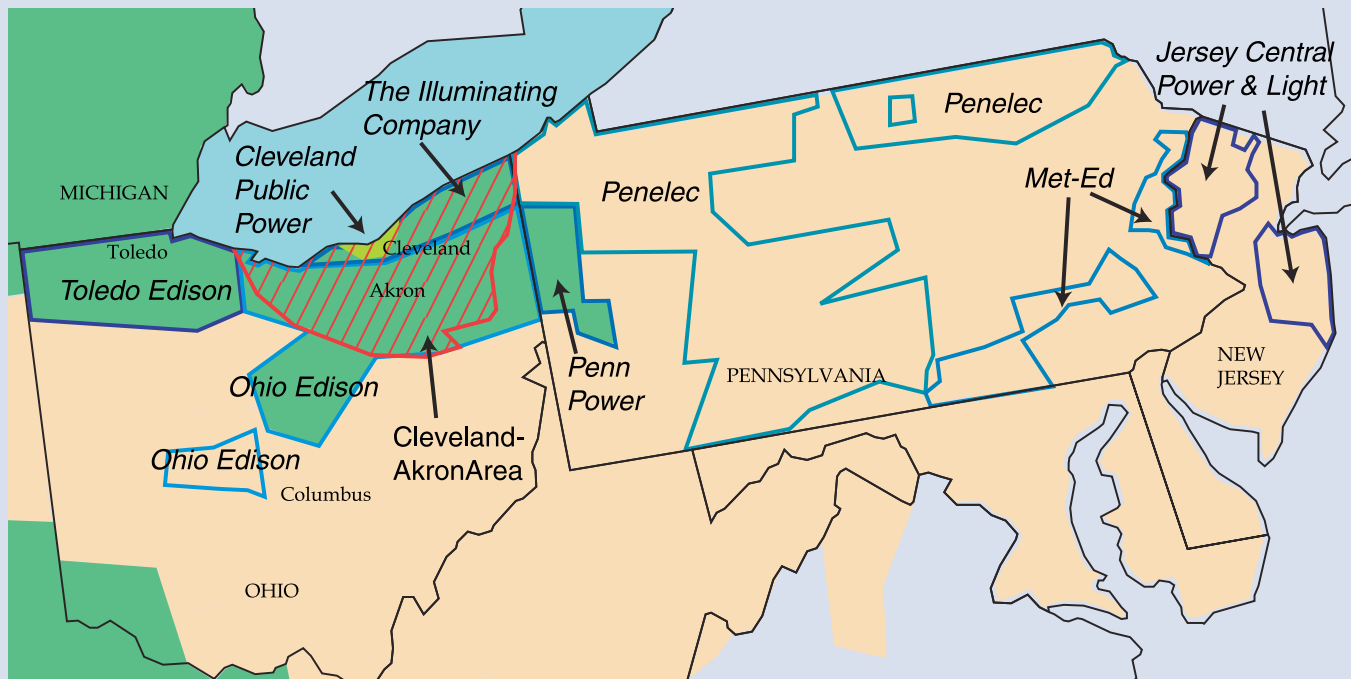
Area	All-Time Peak Load (MW)	Load on August 14, 2003 (MW)
Cleveland-Akron Area (including Cleveland Public Power)	7,340	6,715
FirstEnergy Control Area, Ohio	13,299	12,165
FirstEnergy Retail Area, including PJM	24,267	22,631
NA = not applicable.		

electricity transactions, taking transmission elements out of service or restoring them, and if necessary, shedding interruptible and firm customer load—i.e., cutting some customers off temporarily, and in the right locations, to reduce electricity demand to a level that matches what the system is then able to deliver safely.

This chapter discusses system conditions in and around northeast Ohio on August 14 and their relevance to the blackout. It reviews electric loads (real and reactive), system topology (transmission and generation equipment availability and capabilities), power flows, voltage profiles and reactive power reserves. The discussion examines actual system data, investigation team modeling results, and past FE and AEP experiences in the Cleveland-Akron area. The detailed analyses will be presented in a NERC technical report.

Electric Demands on August 14

Temperatures on August 14 were hot but in a normal range throughout the northeast region of the United States and in eastern Canada (Figure 4.1). Electricity demands were high due to high air conditioning loads typical of warm days in August, though not unusually so. As the temperature increased from 78°F (26°C) on August 11 to 87°F (31°C) on August 14, peak load within FirstEnergy's control area increased by 20%, from 10,095 MW to 12,165 MW. System operators had successfully managed higher demands in northeast Ohio and across the Midwest, both earlier in the summer and in previous years—historic peak load for FE's control area was 13,299 MW. August 14 was FE's peak demand day in 2003.

Several large operators in the Midwest consistently under-forecasted load levels between August 11 and 14. Figure 4.2 shows forecast and actual power demands for AEP, Michigan Electrical Coordinated Systems (MECS), and FE from August 11 through August 14. Variances between actual and forecast loads are not unusual, but because those forecasts are used for day-ahead planning for generation, purchases, and reactive power management, they can affect equipment availability and schedules for the following day.

The existence of high air conditioning loads across the Midwest on August 14 is relevant because air conditioning loads (like other induction motors) have lower power factors than other customer electricity uses, and consume more reactive power. Because it had been hot for several days in the Cleveland-Akron area, more air conditioners were running to overcome the persistent heat, and consuming relatively high levels of reactive power—further straining the area's limited reactive generation capabilities.

Generation Facilities Unavailable on August 14

Several key generators in the region were out of service going into the day of August 14. On any given day, some generation and transmission capacity is unavailable; some facilities are out for routine maintenance, and others have been forced out by an unanticipated breakdown and require repairs. August 14, 2003, in northeast Ohio was no exception (Table 4.1).

The generating units that were not available on August 14 provide real and reactive power directly to the Cleveland, Toledo, and Detroit areas. Under standard practice, system operators take into account the unavailability of such units and any

Figure 4.1. August 2003 Temperatures in the U.S. Northeast and Eastern Canada
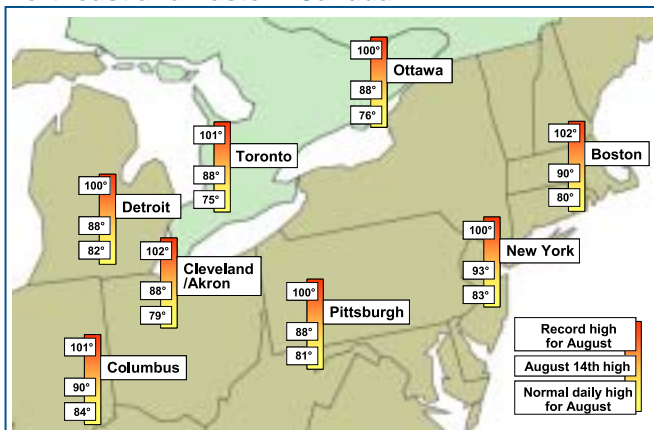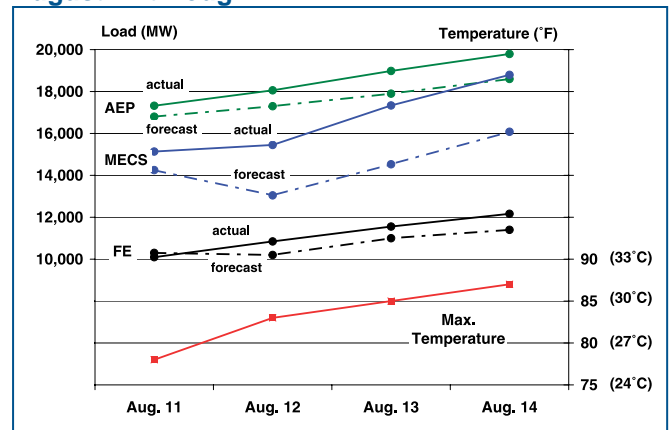

Figure 4.2. Load Forecasts Below Actuals, August 11 through 14

transmission facilities known to be out of service in the day-ahead planning studies they perform to ensure a secure system for the next day. Knowing the status of key facilities also helps operators determine in advance the safe electricity transfer levels for the coming day.

MISO's day-ahead planning studies for August 14 took the above generator outages and transmission outages reported to MISO into account and determined that the regional system could be operated safely. The unavailability of these generation units did not cause the blackout.

On August 14 four or five capacitor banks within the Cleveland-Akron area had been removed from service for routine inspection, including capacitor banks at Fox and Avon 138-kV substations.[1] These static reactive power sources are important for voltage support, but were not restored to

Table 4.1. Generators Not Available on August 14

Generator	Rating	Reason
Davis-Besse Nuclear Unit	883 MW	Prolonged NRC-ordered outage beginning on 3/22/02
Sammis Unit 3	180 MW	Forced outage on 8/12/03
Eastlake Unit 4	238 MW	Forced outage on 8/13/03
Monroe Unit 1	817 MW	Planned outage, taken out of service on 8/8/03
Cook Nuclear Unit 2	1,060 MW	Outage began on 8/13/03

Load Power Factors and Reactive Power

Load power factor is a measure of the relative magnitudes of real power and reactive power consumed by the load connected to a power system. Resistive load, such as electric space heaters or incandescent lights, consumes only real power and no reactive power and has a load power factor of 1.0. Induction motors, which are widely used in manufacturing processes, mining, and homes (e.g., air-conditioners, fan motors in forced-air furnaces, and washing machines) consume both real power and reactive power. Their load power factors are typically in the range of 0.7 to 0.9 during steady-state operation. Single-phase small induction motors (e.g., household items) generally have load power factors in the lower range.

The lower the load power factor, the more reactive power is consumed by the load. For example, a 100 MW load with a load power factor of 0.92 consumes 43 MVAr of reactive power, while the same 100 MW of load with a load power factor of 0.88 consumes 54 MVAr of reactive power. Under depressed voltage conditions, the induction motors used in air-conditioning units and refrigerators, which are used more heavily on hot and humid days, draw even more reactive power than under normal voltage conditions.

In addition to end-user loads, transmission elements such as transformers and transmission lines consume reactive power. Reactive power compensation is required at various locations in the network to support the transmission of real power. Reactive power is consumed within transmission lines in proportion to the square of the electric current shipped, so a 10% increase of power transfer will require a 21% increase in reactive power generation to support the power transfer.

In metropolitan areas with summer peaking loads, it is generally recognized that as temperatures and humidity increase, load demand increases significantly. The power factor impact can be quite large—for example, for a metropolitan area of 5 million people, the shift from winter peak to summer peak demand can shift peak load from 9,200 MW in winter to 10,000 MW in summer; that change to summer electric loads can shift the load power factor from 0.92 in winter down to 0.88 in summer; and this will increase the MVAr load demand from 3,950 in winter up to 5,400 in summer—all due to the changed composition of end uses and the load factor influences noted above.

Reactive power does not travel far, especially under heavy load conditions, and so must be generated close to its point of consumption. This is why urban load centers with summer peaking loads are generally more susceptible to voltage instability than those with winter peaking loads. Thus, control areas must continually monitor and evaluate system conditions, examining reactive reserves and voltages, and adjust the system as necessary for secure operation.

service that afternoon despite the system operators' need for more reactive power in the area.[2] Normal utility practice is to inspect and maintain reactive resources in off-peak seasons so the facilities will be fully available to meet peak loads.

Cause 1
Inadequate System Understanding

The unavailability of the critical reactive resources was not known to those outside of FirstEnergy. NERC policy requires that critical facilities be identified and that neighboring control areas and reliability coordinators be made aware of the status of those facilities to identify the impact of those conditions on their own facilities. However, FE never identified these capacitor banks as critical and so did not pass on status information to others.

Recommendations 23, page 160; 30, page 163

Unanticipated Outages of Transmission and Generation on August 14

Three notable unplanned outages occurred in Ohio and Indiana on August 14 before 15:05 EDT. Around noon, several Cinergy transmission lines in south-central Indiana tripped; at 13:31 EDT, FE's Eastlake 5 generating unit along the southwestern shore of Lake Erie tripped; at 14:02 EDT, a line within the Dayton Power and Light (DPL) control area, the Stuart-Atlanta 345-kV line in southern Ohio, tripped. Only the Eastlake 5 trip was electrically significant to the FirstEnergy system.

◆ Transmission lines on the Cinergy 345-, 230-, and 138-kV systems experienced a series of outages starting at 12:08 EDT and remained out of service during the entire blackout. The loss of these lines caused significant voltage and loading problems in the Cinergy area. Cinergy made generation changes, and MISO operators responded by implementing transmission loading relief (TLR) procedures to control flows on the transmission system in south-central Indiana. System modeling by the investigation team (see details below, pages 41-43) showed that the loss of these lines was not electrically related to subsequent events in northern Ohio that led to the blackout.

◆ The Stuart-Atlanta 345-kV line, operated by DPL, and monitored by the PJM reliability coordinator, tripped at 14:02 EDT. This was the result of a tree contact, and the line remained out of service the entire afternoon. As explained below, system modeling by the investigation

team has shown that this outage did not cause the 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 it had gone out of service. This led to a data mismatch that prevented MISO's state estimator (a key monitoring tool) from producing usable results later in the day at a time when system conditions in FE's control area were deteriorating (see details below, pages 46 and 48-49).

Recommendation 30, page 163

◆ Eastlake Unit 5 is a 597 MW (net) generating unit located west of Cleveland on Lake Erie. It is a major source of reactive power support for the Cleveland area. It tripped at 13:31 EDT. The cause of the trip was that as the Eastlake 5 operator sought to increase the unit's reactive power output (Figure 4.3), the unit's protection system detected that VAr output exceeded the unit's VAr capability and tripped the unit off-line. The loss of the Eastlake 5 unit did not put the grid into an unreliable state—i.e., it was still able to withstand safely another contingency. However, the loss of the unit required FE to import additional power to make up for the loss of the unit's output (612 MW), made voltage management in northern Ohio more challenging, and gave FE operators less flexibility in operating their system (see details on pages 45-46 and 49-50).

Key Parameters for the Cleveland-Akron Area at 15:05 EDT

The investigation team benchmarked their power flow models against measured data provided by

Figure 4.3. MW and MVAr Output from Eastlake Unit 5 on August 14
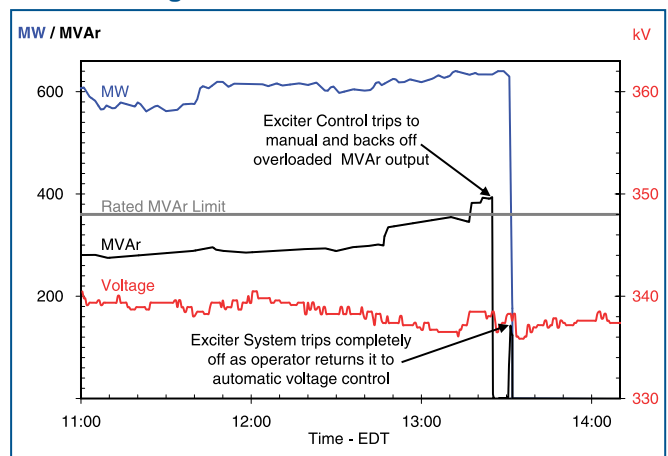
FirstEnergy for the Cleveland-Akron area at 15:05 EDT (just before the first of FirstEnergy's key transmission lines failed), as shown in Table 4.2. Although the modeled figures do not match actual system conditions perfectly, overall this model shows a very high correspondence to the actual occurrences and thus its results merit a high degree of confidence. Although Table 4.2 shows only a few key lines within the Cleveland-Akron area, the model was successfully benchmarked to match actual flows, line-by-line, very closely across the entire area for the afternoon of August 14, 2003.

The power flow model assumes the following system conditions for the Cleveland-Akron area at 15:05 EDT on August 14:

◆ Cleveland-Akron area load = 6,715 MW and 2,402 MVAr

◆ Transmission losses = 189 MW and 2,514 MVAr

◆ Reactive power from fixed shunt capacitors (all voltage levels) = 2,585 MVAr

◆ Reactive power from line charging (all voltage levels) = 739 MVAr

◆ Network configuration = after the loss of Eastlake 5, before the loss of Harding-Chamberlin 345-kV line

◆ Area generation combined output: 3,000 MW and 1,200 MVAr.

Cause 1
Inadequate System Understanding

Given these conditions, the power flow model indicates that about 3,900 MW and 400 MVAr of real power and reactive power flow into the Cleveland-Akron area was needed to meet the sum of customer load demanded plus line losses. There was about 688 MVAr of reactive reserve from generation in the area, which is slightly more than the 660 MVAr reactive capability of the Perry nuclear unit. Combined with the fact that a 5% reduction in operating voltage would cause a 10% reduction in

reactive power (330 MVAr) from shunt capacitors and line charging and a 10% increase (250 MVAr) in reactive losses from transmission lines, these parameters indicate that the Cleveland-Akron area would be precariously short of reactive power if the Perry plant were lost.

Power Flow Patterns

Several commentators have suggested that the voltage problems in northeast Ohio and the subsequent blackout occurred due to unprecedented high levels of inter-regional power transfers occurring on August 14. Investigation team analysis indicates that in fact, power transfer levels were high but were within established limits and previously experienced levels. Analysis of actual and test case power flows demonstrates that inter-regional power transfers had a minimal effect on the transmission corridor containing the Harding-Chamberlin, Hanna-Juniper, and Star-South Canton 345-kV lines on August 14. It was the increasing native load relative to the limited amount of reactive power available in the Cleveland-Akron area that caused the depletion of reactive power reserves and declining voltages.

On August 14, the flow of power through the ECAR region as a whole (lower Michigan, Indiana, Ohio, Kentucky, West Virginia, and western Pennsylvania) was heavy as a result of transfers of power from the south (Tennessee, etc.) and west (Wisconsin, Minnesota, Illinois, Missouri, etc.) to the north (Ohio, Michigan, and Ontario) and east (New York, Pennsylvania). The destinations for much of the power were northern Ohio, Michigan, PJM, and Ontario. This is shown in Figure 4.4, which shows the flows between control areas on August 14 based on power flow simulations just before the Harding-Chamberlin line tripped at 15:05 EDT. FE's total load peaked at 12,165MW at 16:00 EDT. Actual system data indicate that between 15:00 and 16:00 EDT, actual line flows into FE's control area were 2,695 MW for both transactions and native load.

Table 4.2. Benchmarking Model Results to Actual

FE Circuit		MVA Comparison		
From	**To**	**Model Base Case MVA**	**Actual 8/14 MVA**	**Benchmark Accuracy**
Chamberlin	Harding	482	500	3.6%
Hanna	Juniper	1,009	1,007	0.2%
S. Canton	Star	808	810	0.2%
Tidd	Canton Central	633	638	0.8%
Sammis	Star	728	748	2.7%

Figure 4.4. Generation, Demand, and Interregional Power Flows on August 14, 2003, at 15:05 EDT
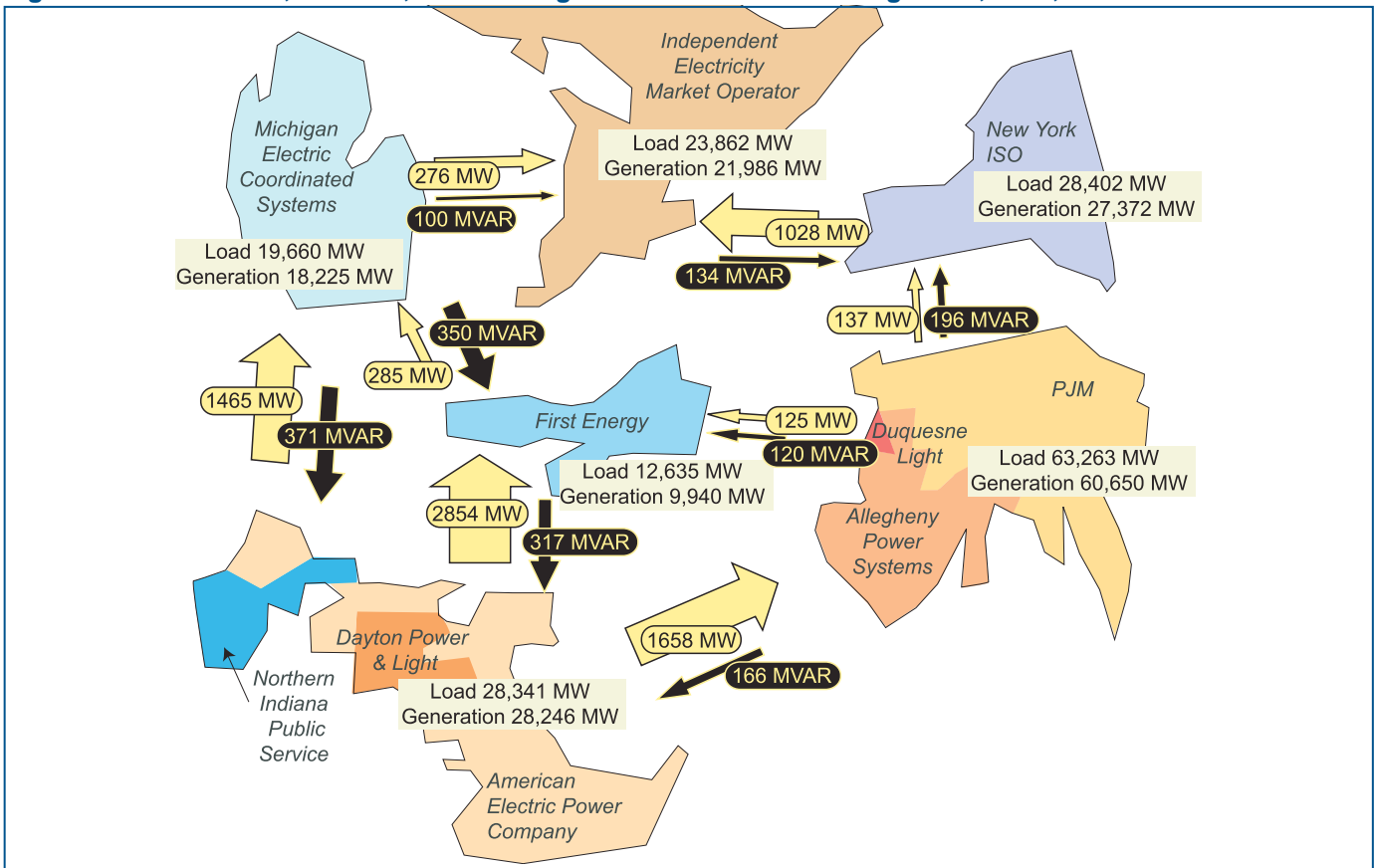

Figure 4.5 shows total scheduled imports for the entire northeast region for June through August 14, 2003. These transfers were well within the range of previous levels, as shown in Figure 4.5, and well within all established limits. In particular, on August 14 increasing amounts of the growing imports into the area were being delivered to FirstEnergy's Ohio territory to meet its increasing demand and to replace the generation lost with the trip of Eastlake 5. The level of imports into Ontario from the U.S. on August 14 was high (e.g., 1,334 MW at 16:00 EDT through the New York and Michigan ties) but not unusual, and well within IMO's import capability. Ontario is a frequent importer and exporter of power, and had imported similar and higher amounts of power several times during the summers of 2002 and 2003. PJM and Michigan also routinely import and export power across ECAR.

Some have suggested that the level of power flows into and across the Midwest was a direct cause of the blackout on August 14. Investigation team modeling proves that these flows were neither a cause nor a contributing factor to the blackout. The team used detailed modeling and simulation incorporating the NERC TagNet data on actual

Figure 4.5. Scheduled Imports and Exports for the Northeast Central Region, June 1 through August 13, 2003
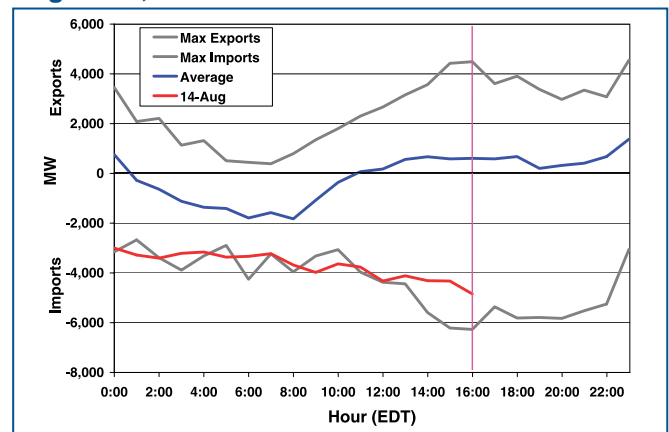
Note: These flows from within the Northeast Central Area include ECAR, PJM, IMO, NYISO, and exclude transfers from Québec, the Maritimes and New England, since the latter areas had minimal flows across the region of interest.

transactions to determine whether and how the transactions affected line loadings within the Cleveland-Akron area. The MUST (Managing Utilization of System Transmission) analytical tool uses the transactions data from TagNet along with a power flow program to determine the impact of transactions on the loading of transmission

flowgates or specific facilities, calculating transfer distribution factors across the various flowgates. The MUST analysis shows that for actual flows at 15:05 EDT, only 10% of the loading on Cleveland-Akron lines was for through flows for which FE was neither the importer nor exporter.

According to real-time TagNet records, at 15:05 EDT the incremental flows due to transactions were approximately 2,800 MW flowing into the FirstEnergy control area and approximately 800 MW out of FE to Duquesne Light Company (DLCO). Among the flows into or out of the FE control area, the bulk of the flows were for transactions where FE was the recipient or the source—at 15:05 EDT the incremental flows due to transactions into FE were 1,300 MW from interconnections with PJM, AEP, DPL and MECS, and approximately 800 MW from interconnections with DLCO. But not all of that energy moved through the Cleveland-Akron area and across the lines which failed on August 14, as Figure 4.6 shows.

Figure 4.6 shows how all of the transactions flowing across the Cleveland-Akron area on the afternoon of August 14 affected line loadings at key FE facilities, organized by time and types of transactions. It shows that before the first transmission line failed, the bulk of the loading on the four critical FirstEnergy circuits—Harding-Chamberlin, Hanna-Juniper, Star-South Canton and Sammis-Star—was to serve Cleveland-Akron area native load. Flows to serve native load included transfers from FE's 1,640 MW Beaver Valley nuclear power plant and its Seneca plant, both in Pennsylvania, which have been traditionally counted by FirstEnergy not as imports but rather as in-area

Figure 4.6. Impacts of Transactions Flows on Critical Line Loadings, August 14, 2003
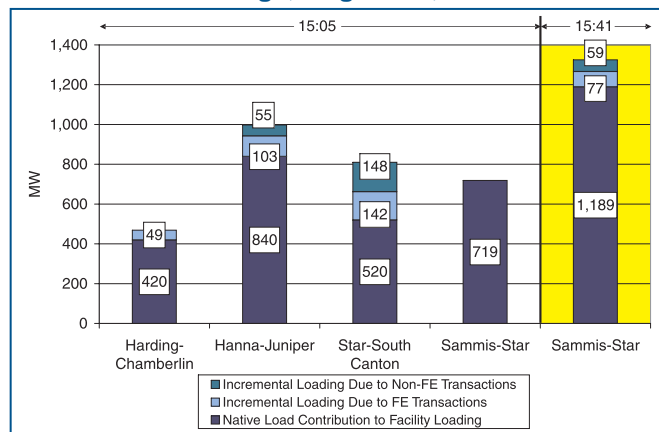
generation, and as such excluded from TLR curtailments. An additional small increment of line loading served transactions for which FE was either the importer or exporter, and the remaining line loading was due to through-flows initiated and received by other entities. The Star-South Canton line experienced the greatest impact from through-flows—148 MW, or 18% of the total line loading at 15:05 EDT, was due to through-flows resulting from non-FE transactions. By 15:41 EDT, right before Star-South Canton tripped—without being overloaded—the Sammis-Star line was serving almost entirely native load, with loading from through-flows down to only 4.5%.

Cause 1
Inadequate System Understanding

The central point of this analysis is that because the critical lines were loaded primarily to serve native load and FE-related flows, attempts to reduce flows through transaction curtailments in and around the Cleveland-Akron area would have had minimal impact on line loadings and the declining voltage situation within that area. Rising load in the Cleveland-Akron area that afternoon was depleting the remaining reactive power reserves. Since there was no additional in-area generation, only in-area load cuts could have reduced local line loadings and improved voltage security. This is confirmed by the loadings on the Sammis-Star at 15:42 EDT, after the loss of Star-South Canton—fully 96% of the current on that line was to serve FE load and FE-related transactions, and a cut of *every non-FE through transaction* flowing across northeast Ohio would have obtained only 59 MW (4%) of relief for this specific line. This means that redispatch of generation beyond northeast Ohio would have had almost no impact upon conditions within the Cleveland-Akron area (which after 13:31 EDT had no remaining generation reserves). Equally important, cutting flows on the Star-South Canton line might not have changed subsequent events—because the line opened three times that afternoon due to tree contacts, reducing its loading would not have assured its continued operation.

Recommendations 3, page 143; 23, page 160

Power flow patterns on August 14 did not cause the blackout in the Cleveland-Akron area. But once the first four FirstEnergy lines went down, the magnitude and pattern of flows on the overall system did affect the ultimate path, location and speed of the cascade after 16:05:57 EDT.[3]

Voltages and Voltage Criteria

During the days before August 14 and throughout the morning and mid-day on August 14, voltages were depressed across parts of northern Ohio because of high air conditioning demand and other loads, and power transfers into and to a lesser extent across the region. Voltage varies by location across an electrical region, and operators monitor voltages continuously at key locations across their systems.

Entities manage voltage using long-term planning and day-ahead planning for adequate reactive supply, and real-time adjustments to operating equipment. On August 14, for example, PJM implemented routine voltage management procedures developed for heavy load conditions. Within Ohio, FE began preparations early in the afternoon of August 14, requesting capacitors to be restored to service[4] and additional voltage support from generators.[5] As the day progressed, operators across the region took additional actions, such as increasing plants' reactive power output, plant redispatch, and transformer tap changes to respond to changing voltage conditions.

Voltages at key FirstEnergy buses (points at which lines, generators, transformers, etc., converge)

were declining over the afternoon of August 14. Actual measured voltage levels at the Star bus and others on FE's transmission system on August 14 were below 100% starting early in the day. At 11:00 EDT, voltage at the Star bus equaled 98.5%, declined to 97.3% after the loss of Eastlake 5 at 13:31 EDT, and dropped to 95.9% at 15:05 EDT after the loss of the Harding-Chamberlin line. FirstEnergy system operators reported this voltage performance to be typical for a warm summer day on the FirstEnergy system. The gradual decline of voltage over the early afternoon was consistent with the increase of load over the same time period, particularly given that FirstEnergy had no additional generation within the Cleveland-Akron area load pocket to provide additional reactive support.

Cause 1
Inadequate System Understanding

NERC and regional reliability councils' planning criteria and operating policies (such as NERC I.A and I.D, NPCC A-2, and ECAR Document 1) specify voltage criteria in such generic terms as: acceptable voltages under normal and emergency conditions shall be maintained within normal limits and applicable emergency limits respectively, with due recognition to avoiding voltage instability and widespread system collapse in the event of certain contingencies. Each system then defines its own

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Do ATC and TTC Matter for Reliability?

Each transmission provider calculates Available Transfer Capability (ATC) and Total Transfer Capability (TTC) as part of its Open Access Transmission Tariff, and posts those on the OASIS to enable others to plan power purchase transactions. TTC is the forecast amount of electric power that can be transferred over the interconnected transmission network in a reliable manner under specific system conditions. ATCs are forecasts of the amount of transmission available for additional commercial trade above projected committed uses. These are not real-time operating security limits for the grid.

The monthly TTC and ATC values for August 2003 were first determined a year previously; those for August 14, 2003 were calculated 30 days in advance; and the hourly TTC and ATC values for the afternoon of August 14 were calculated approximately seven days ahead using forecasted system conditions. Each of these values should be updated as the forecast of system

conditions changes. Thus the TTC and ATC are advance estimates for commercial purposes and do not directly reflect actual system conditions. NERC's operating procedures are designed to manage actual system conditions, not forecasts such as ATC and TTC.

Within ECAR, ATCs and TTCs are determined on a first contingency basis, assuming that only the most critical system element may be forced out of service during the relevant time period. If actual grid conditions—loads, generation dispatch, transaction requests, and equipment availability—differ from the conditions assumed previously for the ATC and TTC calculation, then the ATC and TTC have little relevance for actual system operations. Regardless of what pre-calculated ATC and TTC levels may be, system operators must use real-time monitoring and contingency analysis to track and respond to real-time facility loadings to assure that the transmission system is operated reliably.

acceptable voltage criteria based on its own system design and equipment characteristics, detailing quantified measures including acceptable minimum and maximum voltages in percentages of nominal voltage and acceptable voltage declines from the pre-contingency voltage. Good utility practice requires that these determinations be based on a full set of V-Q (voltage performance V relative to reactive power supply Q) and P-V (real power transfer P relative to voltage V)

Competition and Increased Electric Flows

Besides blaming high inter-regional power flows for causing the blackout, some blame the existence of those power flows upon wholesale electric competition. Before 1978, most power plants were owned by vertically-integrated utilities; purchases between utilities occurred when a neighbor had excess power at a price lower than other options. A notable increase in inter-regional power transfers occurred in the mid-1970s after the oil embargo, when eastern utilities with a predominance of high-cost oil-fired generation purchased coal-fired energy from Midwestern generators. The 1970s and 1980s also saw the development of strong north-to-south trade between British Columbia and California in the west, and Ontario, Québec, and New York-New England in the east. Americans benefited from Canada's competitively priced hydroelectricity and nuclear power while both sides gained from seasonal and daily banking and load balancing—Canadian provinces had winter peaking loads while most U.S. utilities had primarily summer peaks.

In the United States, wholesale power sales by independent power producers (IPPs) began after passage of the Public Utility Regulatory Policy Act of 1978, which established the right of non-utility producers to operate and sell their energy to utilities. This led to extensive IPP development in the northeast and west, increasing in-region and inter-regional power sales as utility loads grew without corresponding utility investments in transmission. In 1989, investor-owned utilities purchased 17.8% of their total energy (self-generation plus purchases) from other utilities and IPPs, compared to 37.3% in 2002; and in 1992, large public power entities purchased 36.3% of total energy (self-generation plus purchases), compared to 40.5% in 2002.[a]

In the Energy Policy Act of 1992, Congress continued to promote the development of competitive energy markets by introducing exempt wholesale generators that would compete with utility generation in wholesale electric markets (see Section 32 of the Public Utility Holding Company Act). Congress also broadened the authority of the Federal Energy Regulatory Commission to order transmission access on a case-by-case basis under Section 211 of the Federal Power Act. Consistent with this Congressional action, the Commission in Order 888 ordered all public utilities that own, operate, or control interstate transmission facilities to provide open access for sales of energy transmitted over those lines.

Competition is not the only thing that has grown over the past few decades. Between 1986 and 2002, peak demand across the United States grew by 26%, and U.S. electric generating capacity grew by 22%,[b] but U.S. transmission capacity grew little beyond the interconnection of new power plants. Specifically, "the amount of transmission capacity per unit of consumer demand declined during the past two decades and . . . is expected to drop further in the next decade."[c]

Load-serving entities today purchase power for the same reason they did before the advent of competition—to serve their customers with low-cost energy—and the U.S. Department of Energy estimates that Americans save almost $13 billion (U.S.) annually on the cost of electricity from the opportunity to buy from distant, economical sources. But it is likely that the increased loads and flows across a transmission grid that has experienced little new investment is causing greater "stress upon the hardware, software and human beings that are the critical components of the system."[d] A thorough study of these issues has not been possible as part of the Task Force's investigation, but such a study would be worthwhile. For more discussion, see Recommendation 12, page 148.

[a]RDI PowerDat database.
[b]U.S. Energy Information Administration, *Energy Annual Data Book*, 2003 edition.
[c]Dr. Eric Hirst, "Expanding U.S. Transmission Capacity," August 2000, p. vii.
[d]Letter from Michael H. Dworkin, Chairman, State of Vermont Public Service Board, February 11, 2004, to Alison Silverstein and Jimmy Glotfelty.

analyses for a wide range of system conditions. Table 4.3 compares the voltage criteria used by FirstEnergy and other relevant transmission operators in the region. As this table shows, FE uses minimum acceptable normal voltages which are lower than and incompatible with those used by its interconnected neighbors.

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Cause 1
Inadequate System Understanding

The investigation team probed deeply into voltage management issues within the Cleveland-Akron area. As noted previously, a power system with higher operating voltage and larger reactive power reserves is more resilient or robust in the face of load increases and operational contingencies. Higher transmission voltages enable higher power transfer capabilities and reduce transmission line losses (both real and reactive). For the Cleveland-Akron area, FE has been operating the system with the minimum voltage level at 90% of nominal rating, with alarms set at 92%.[6] The criteria allow for a single contingency to occur if voltage remains above 90%. The team conducted extensive voltage stability studies (discussed below), concluding that FE's 90% minimum voltage level was not only far less stringent than nearby interconnected systems (most of which set the pre-contingency minimum voltage criteria at 95%), but was not adequate for secure system operations.

Examination of the Form 715 filings made by Ohio Edison, FE's predecessor company, for 1994 through 1997 indicate that Ohio Edison used a pre-contingency bus voltage criteria of 95 to 105 % and 90% emergency post-contingency voltage, with acceptable change in voltage no greater than 5%. These historic criteria were compatible with neighboring transmission operator practices.

A look at voltage levels across the region illustrates the difference between FE's voltage situation on August 14 and that of its neighbors.

Cause 1
Inadequate System Understanding

Figure 4.7 shows the profile of voltage levels at key buses from southeast Michigan across Ohio into western Pennsylvania from August 11 through 14 and for several hours on August 14. These transects show that across the area, voltage levels were consistently lower at the 345-kV buses in the Cleveland-Akron area (from Beaver to Hanna on the west to east plot and from Avon Lake to Star on the north to south plot) for the three days and the 13:00 to 15:00 EDT period preceding the blackout. Voltage was consistently and considerably higher at the outer ends of each transect, where it never dropped below 96% even on August 14. These profiles also show clearly the decline of voltage over the afternoon of August 14, with voltage at the Harding bus at 15:00 EDT just below 96% before the Harding-Chamberlin line tripped at 15:05 EDT, and dropping down to around 93% at 16:00 EDT after the loss of lines and load in the immediate area.

Cause 1
Inadequate System Understanding

Using actual data provided by FE, ITC, AEP and PJM, Figure 4.8 shows the availability of reactive reserves (the difference between reactive power generated and the maximum reactive capability) within the Cleveland-Akron area and four regions surrounding it, from ITC to PJM. On the afternoon of August 14, the graph shows that reactive power generation was heavily taxed in the Cleveland-Akron area but that extensive MVAr reserves were available in the neighboring areas. As the afternoon progressed, reactive reserves diminished for all five regions as load grew. But reactive reserves were fully depleted within the Cleveland-Akron area by 16:00 EDT without drawing down the reserves in neighboring areas, which remained at scheduled voltages. The region as a whole had sufficient reactive reserves, but because reactive power cannot be transported far but must be supplied from

Table 4.3. Comparison of Voltage Criteria (Percent)

345 kV/138 kV	FE	PJM	AEP	METC[a]	ITC[b]	MISO	IMO[c]
High	105	105	105	105	105	105	110
Normal Low	90	95	95	97	95	95	98
Emergency/Post N-1 Low.	90	92	90[d]		87		94
Maximum N-1 deviation	5[e]			5			10

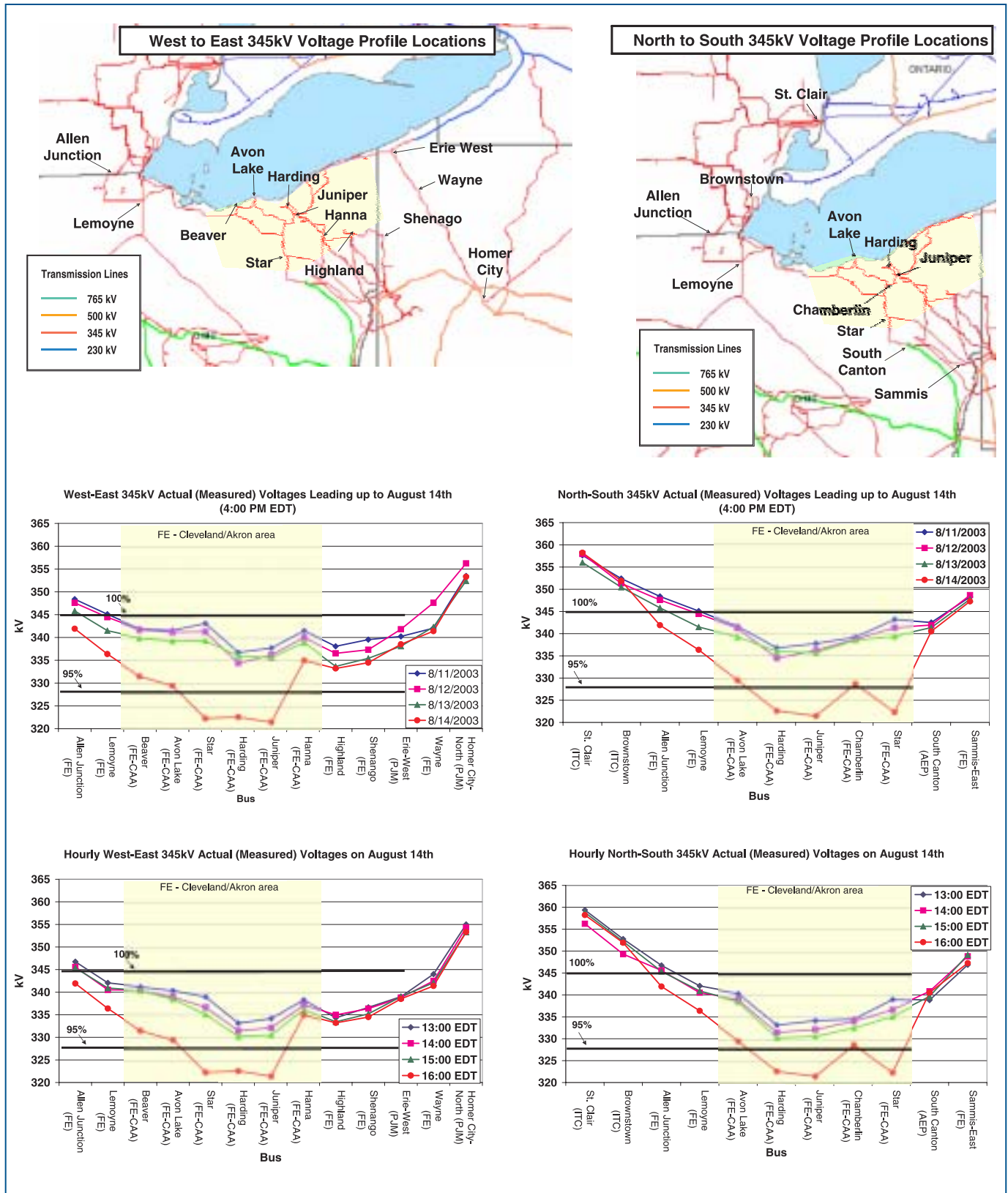[a]Applies to 138 kV only. 345 kV not specified.
[b]Applies to 345 kV only. Min-max normal voltage for 120 kV and 230 kV is 93-105%.
[c]500 kV.
[d]92% for 138 kV.
[e]10% for 138 kV.

Figure 4.7. Actual Voltages Across the Ohio Area Before and On August 14, 2003
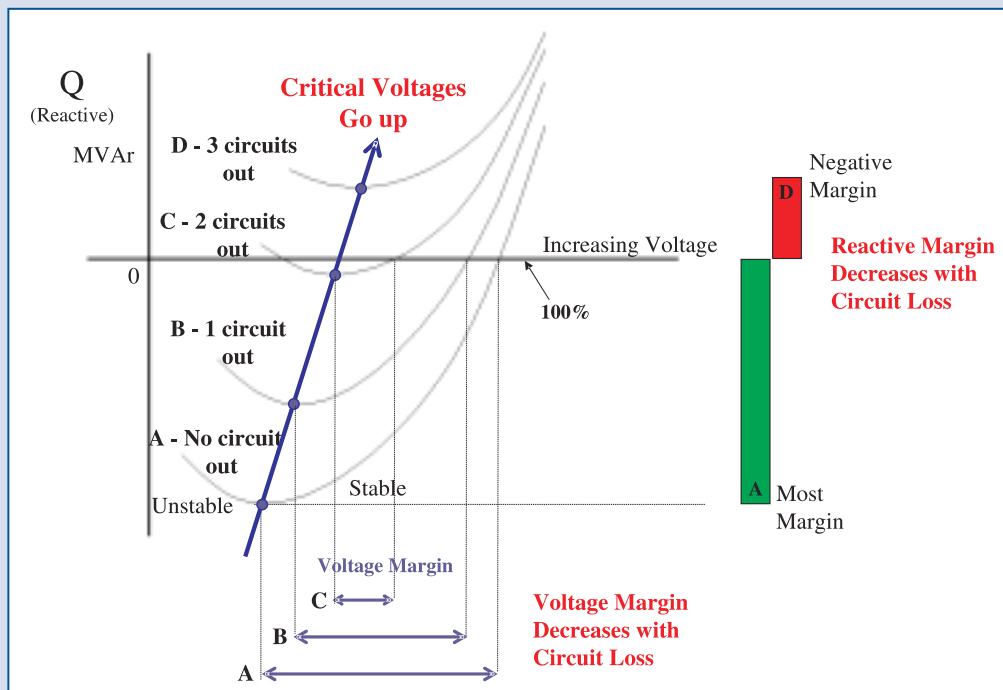
Voltage Stability Analysis

Voltage instability or voltage collapse occurs on a power system when voltages progressively decline until stable operating voltages can no longer be maintained. This is precipitated by an imbalance of reactive power supply and demand, resulting from one or more changes in system conditions including increased real or reactive loads, high power transfers, or the loss of generation or transmission facilities. Unlike the phenomenon of transient instability, where generators swing out of synchronism with the rest of the power system within a few seconds or less after a critical fault, voltage instability can occur gradually within tens of seconds or minutes.

Voltage instability is best studied using V-Q (voltage relative to reactive power) and P-V (real power relative to voltage) analysis. V-Q analysis evaluates the reactive power required at a bus to maintain stable voltage at that bus. A simulated reactive power source is added to the bus, the voltage schedule at the bus is adjusted in small steps from an initial operating point, and power flows are solved to determine the change in reactive power demand resulting from the change in voltage. Under stable operating conditions, when voltage increases the reactive power requirement also increases, and when voltage

falls the reactive requirement also falls. But when voltage is lowered at the bus and the reactive requirement at that bus begins to increase (rather than continuing to decrease), the system becomes unstable. The voltage point corresponding to the transition from stable to unstable conditions is known as the "critical voltage," and the reactive power level at that point is the "reactive margin." The desired operating voltage level should be well above the critical voltage with a large buffer for changes in prevailing system conditions and contingencies. Similarly, reactive margins should be large to assure robust voltage levels and secure, stable system performance.

The illustration below shows a series of V-Q curves. The lowest curve, A, reflects baseline conditions for the grid with all facilities available. Each higher curve represents the same loads and transfers for the region modeled, but with another contingency event (a circuit loss) occurring to make the system less stable. With each additional contingency, the critical voltage rises (the point on the horizontal axis corresponding to the lowest point on the curve) and the reactive margin decreases (the difference between the reactive power at the critical voltage and the zero point on the vertical axis). This means the system is closer to instability.

V-Q (Voltage-Reactive Power) Curves

V-Q analyses and experience with heavily loaded power systems confirm that critical voltage levels can rise above the 95% level traditionally considered as normal. Thus voltage magnitude alone is a poor indicator of voltage stability and V-Q analysis must be carried out for several critical buses in a local area, covering a range of load and generation conditions and known contingencies that affect voltages at these buses.

P-V analysis (real power relative to voltage) is a companion tool which determines the real power transfer capability across a transmission interface for load supply or a power transfer. Starting from a base case system state, a series of load flows with increasing power transfers are solved while monitoring voltages at critical buses. When power transfers reach a high enough level a stable voltage cannot be sustained and the power flow model fails to solve. The point where the power flow last solved corresponds to the critical voltage level found in the V-Q curve for those conditions. On a P-V curve (see below), this point is called the "nose" of the curve.

This set of P-V curves illustrates that for baseline conditions shown in curve A, voltage remains relatively steady (change along the vertical axis) as load increases within the region (moving out along the horizontal axis). System conditions are secure and stable in the area above the "nose" of the curve. After a contingency occurs, such as a transmission circuit or generator trip, the new condition set is represented by curve B, with lower voltages (relative to curve A) for any load on curve B. As the operator's charge is to keep the system stable against the next worst contingency, the system must be operated to stay well inside the load level for the nose of curve B. If the B contingency occurs, there is a next worst contingency curve inside curve B, and the operator must adjust the system to pull back operations to within the safe, buffered space represented by curve C.

The investigation team conducted extensive V-Q and P-V analyses for the area around Cleveland-Akron for the conditions in effect on August 14, 2003. Team members examined over fifty 345-kV and 138-kV buses across the systems of FirstEnergy, AEP, International Transmission Company, Duquesne Light Company, Alleghany Power Systems and Dayton Power & Light. The V-Q analysis alone involved over 10,000 power flow simulations using a system model with more than 43,000 buses and 57,000 lines and transformers. The P-V analyses used the same model and data sets. Both examined conditions and combinations of contingencies for critical times before and after key events on the FirstEnergy system on the day of the blackout.

P-V (Power-Voltage) Curves
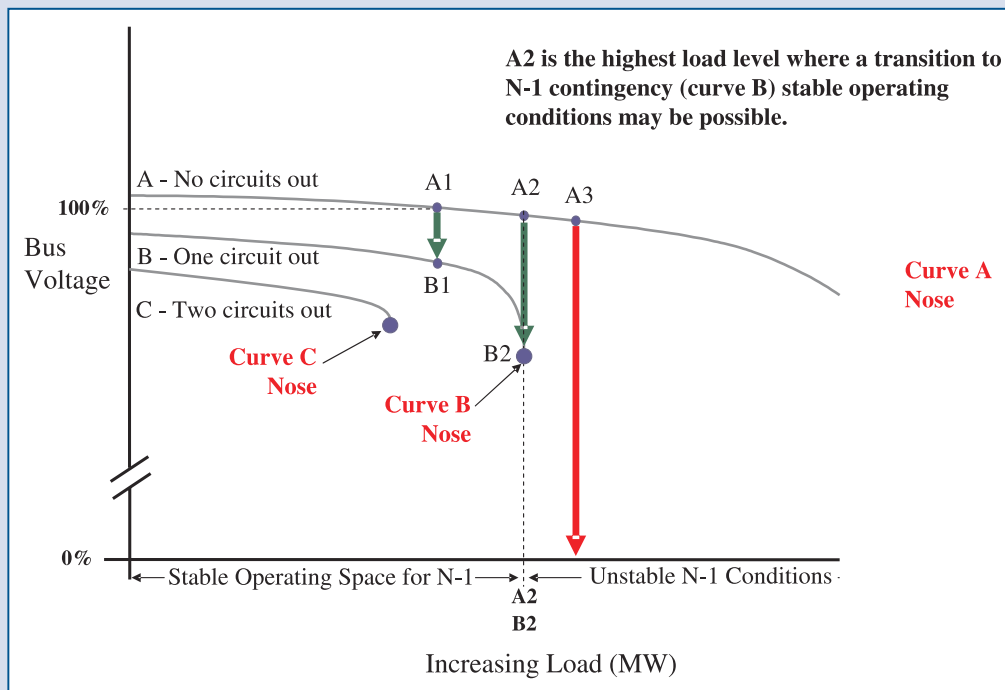
local sources, these healthy reserves nearby could not support the Cleveland-Akron area's reactive power deficiency and growing voltage problems. Even FE's own generation in the Ohio Valley had reactive reserves that could not support the sagging voltages inside the Cleveland-Akron area.

Cause 1
Inadequate
System
Understanding

An important consideration in reactive power planning is to ensure an appropriate balance between static and dynamic reactive power resources across the interconnected system (as specified in NERC Planning Standard 1D.S1). With so little generation left in the Cleveland-Akron area on August 14, the area's dynamic reactive reserves were depleted and the area relied heavily on static compensation to respond to changing system conditions and support voltages. But a system relying on static compensation can experience a gradual voltage degradation followed by a sudden drop in voltage stability—the P-V curve for such a system has a very steep slope close to the nose, where voltage collapses. On August 14, the lack of adequate dynamic reactive reserves, coupled with not knowing the critical voltages and maximum import capability to serve native load, left the Cleveland-Akron area in a very vulnerable state.

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Past System Events and Adequacy of System Studies

Cause 1
Inadequate
System
Understanding

In June 1994, with three generators in the Cleveland area out on maintenance, inadequate reactive reserves and falling voltages in the Cleveland area forced Cleveland Electric Illuminating (CEI, a predecessor company to FirstEnergy) to shed load within Cleveland (a municipal utility and wholesale transmission and purchase customers within CEI's control area) to avoid voltage collapse.[7] The Cleveland-Akron area's voltage problems were well-known and reflected in the stringent voltage criteria used by control area operators until 1998.[8]

Cause 1
Inadequate
System
Understanding

In the summer of 2002, AEP's South Canton 765 kV to 345 kV transformer (which connects to FirstEnergy's Star 345-kV line) experienced eleven days of severe overloading when actual loadings exceeded normal rating and contingency loadings were at or above summer emergency ratings. In each instance, AEP took all available actions short of load shedding to return the system to a secure state, including TLRs, switching, and dispatch adjustments. These excessive loadings were

Figure 4.8. Reactive Reserves Around Ohio on August 14, 2003, for Representative Generators in the Area
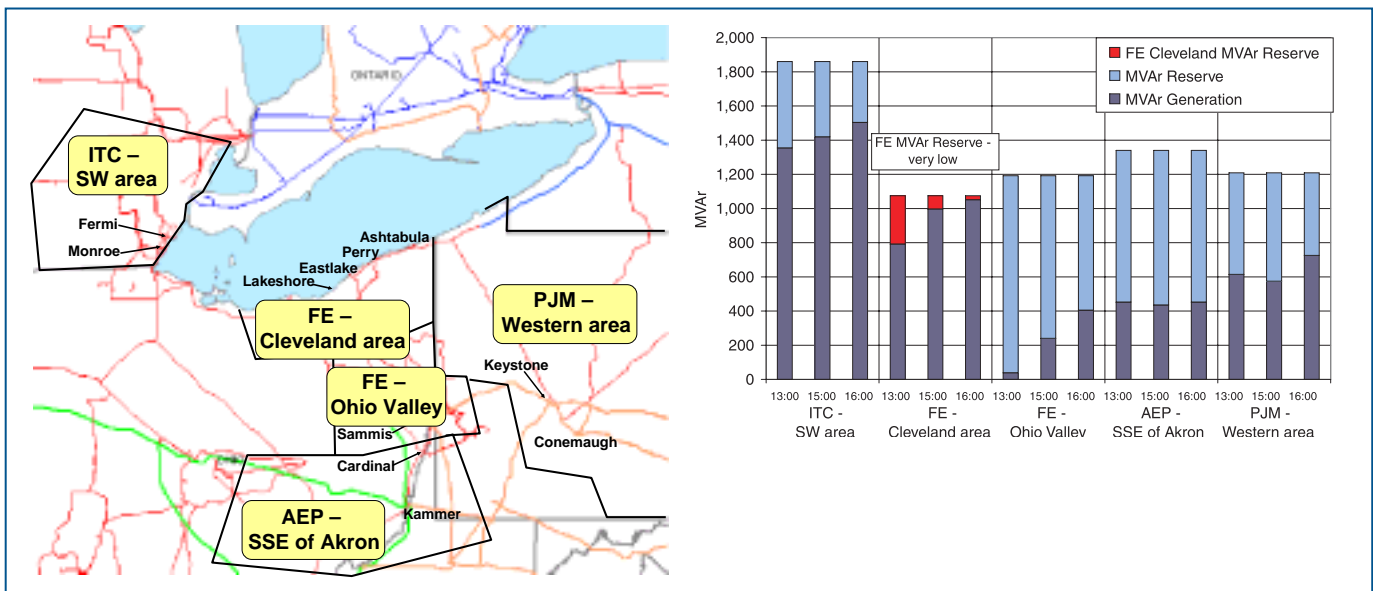
Note: These reactive reserve MVAr margins were calculated for the five regions for the following plants: (1) Cleveland area of FirstEnergy—Ashtabula 5, Perry 1, Eastlake 1, Eastlake 3, Lakeshore 18; (2) Northern central portion of AEP near FirstEnergy (South-Southeast of Akron)—Cardinal 1, Cardinal 2, Cardinal 3, Kammer 2, Kammer 3; (3) Southwest area of MECS (ITC)—Fermi 1, Monroe 2, Monroe 3, Monroe 4; (4) Ohio Valley portion of FirstEnergy—Sammis 4, Sammis 5, Sammis 6, Sammis 7; (5) Western portion of PJM—Keystone 1, Conemaugh 1, Conemaugh 2.

calculated to have diminished the remaining life of the transformer by 30%. AEP replaced this single phase transformer in the winter of 2002-03, marginally increasing the capacity of the South Canton transformer bank.

Following these events, AEP conducted extensive modeling to understand the impact of a potential outage of this transformer. That modeling revealed that loss of the South Canton transformer, especially if it occurred in combination with outages of other critical facilities, would cause significant low voltages and overloads on both the AEP and FirstEnergy systems. AEP shared these findings with FirstEnergy in a meeting on January 10, 2003.[9]

AEP subsequently completed a set of system studies, including long range studies for 2007, which included both single contingency and extreme

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Independent Power Producers and Reactive Power

Independent power producers (IPPs) are power plants that are not owned by utilities. They operate according to market opportunities and their contractual agreements with utilities, and may or may not be under the direct control of grid operators. An IPP's reactive power obligations are determined by the terms of its contractual interconnection agreement with the local transmission owner. Under routine conditions, some IPPs provide limited reactive power because they are not required or paid to produce it; they are only paid to produce active power. (Generation of reactive power by a generator can require scaling back generation of active power.) Some contracts, however, compensate IPPs for following a voltage schedule set by the system operator, which requires the IPP to vary its output of reactive power as system conditions change. Further, contracts typically require increased reactive power production from IPPs when it is requested by the control area operator during times of a system emergency. In some contracts, provisions call for the payment of opportunity costs to IPPs when they are called on for reactive power (i.e., they are paid the value of foregone active power production).

Thus, the suggestion that IPPs may have contributed to the difficulties of reliability management on August 14 because they don't provide reactive power is misplaced. What the IPP is required to produce is governed by contractual arrangements, which usually include provisions for contributions to reliability, particularly during system emergencies. More importantly, it is the responsibility of system planners and operators, not IPPs, to plan for reactive power requirements and make any short-term arrangements needed to ensure that adequate reactive power resources will be available.

Power Flow Simulation of Pre-Cascade Conditions

The bulk power system has no memory. It does not matter if frequencies or voltage were unusual an hour, a day, or a month earlier. What matters for reliability are loadings on facilities, voltages, and system frequency at a given moment and the collective capability of these system components at that same moment to withstand a contingency without exceeding thermal, voltage, or stability limits.

Power system engineers use a technique called power flow simulation to reproduce known operating conditions at a specific time by calibrating an initial simulation to observed voltages and line flows. The calibrated simulation can then be used to answer a series of "what if" questions to determine whether the system was in a safe operating state at that time. The "what if" questions consist of systematically simulating outages by removing key elements (e.g., generators or trans-

mission lines) one by one and reassessing the system each time to determine whether line or voltage limits would be exceeded. If a limit is exceeded, the system is not in a secure state. As described in Chapter 2, NERC operating policies require operators, upon finding that their system is not in a reliable state, to take immediate actions to restore the system to a reliable state as soon as possible and within a maximum of 30 minutes.

To analyze the evolution of the system on the afternoon of August 14, this process was followed to model several points in time, corresponding to key transmission line trips. For each point, three solutions were obtained: (1) conditions immediately before a facility tripped off; (2) conditions immediately after the trip; and (3) conditions created by any automatic actions taken following the trip.

disturbance possibilities. These studies showed that with heavy transfers to the north, expected overloading of the South Canton transformer and depressed voltages would occur following the loss of the Perry unit and the loss of the Tidd-Canton Central 345-kV line, and probable cascading into voltage collapse across northeast Ohio would occur for nine different double contingency combinations of generation and transmission or transmission and transmission outages.[10] AEP shared these findings with FirstEnergy in a meeting on May 21, 2003. Meeting notes indicate that "neither AEP or FE were able to identify any changes in transmission configuration or operating procedures which could be used during 2003 summer to be able to control power flows through the S. Canton bank."[11] Meeting notes include an action item that both "AEP and FE would share the results of these studies and expected performance for 2003 summer with their Management and Operations personnel."[12]

Reliability coordinators and control areas prepare regional and seasonal studies for a variety of system-stressing scenarios, to better understand potential operational situations, vulnerabilities, risks, and solutions. However, the studies FirstEnergy relied on—both by FirstEnergy and ECAR—were not robust, thorough, or up-to-date. This left FE's planners and operators with a deficient understanding of their system's capabilities and risks under a range of system conditions. None of the past voltage events noted above or the significant risks identified in AEP's 2002-2003 studies are reflected in any FirstEnergy or ECAR seasonal or longer-term planning studies or operating protocols available to the investigation team.

Cause 1
Inadequate System Understanding

FE's 2003 Summer Study focused primarily on single-contingency (N-1) events, and did not consider significant multiple contingency losses and security. FirstEnergy examined only thermal limits and looked at voltage only to assure that voltage levels remained within range of 90 to 105% of nominal voltage on the 345 kV and 138 kV network. The study assumed that only the Davis-Besse power plant (883 MW) would be out of service at peak load of 13,206 MW; on August 14, peak load reached 12,166 MW and scheduled generation outages included Davis-Besse, Sammis 3 (180 MW) and Eastlake 4 (240 MW), with Eastlake 5 (597 MW) lost in real time. The study assumed that all transmission facilities would be in service; on August 14, scheduled transmission outages included the

Eastlake #62 345/138 kV transformer and the Fox #1 138-kV capacitor, with other capacitors down in real time. Last, the study assumed a single set of import and export conditions, rather than testing a wider range of generation dispatch, import-export, and inter-regional transfer conditions. Overall, the summer study posited less stressful system conditions than actually occurred August 14, 2003 (when load was well below historic peak demand). It did not examine system sensitivity to key parameters to determine system operating limits within the constraints of transient stability, voltage stability, and thermal capability.

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Cause 1
Inadequate System Understanding

FirstEnergy has historically relied upon the ECAR regional assessments to identify anticipated reactive power requirements and recommended corrective actions. But ECAR over the past five years has not conducted any detailed analysis of the Cleveland-Akron area and its voltage-constrained import capability—although that constraint had been an operational consideration in the 1990s and was documented in testimony filed in 1996 with the Federal Energy Regulatory Commission.[13] The voltage-constrained import capability was not studied; FirstEnergy had modified the criteria around 1998 and no longer followed the tighter voltage limits used earlier. In the ECAR "2003 Summer Assessment of Transmission System Performance," dated May 2003, First Energy's Individual Company Assessment identified potential overloads for the loss of both Star 345/138 transformers, but did not mention any expected voltage limitation.

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FE participates in ECAR studies that evaluate extreme contingencies and combinations of events. ECAR does not conduct exacting region-wide analyses, but compiles individual members' internal studies of N-2 and multiple contingencies (which may include loss of more than one circuit, loss of a transmission corridor with several transmission lines, loss of a major substation or generator, or loss of a major load pocket). The last such study conducted was published in 2000, projecting system conditions for 2003. That study did not include any contingency cases that resulted in 345-kV line overloading or voltage violations on 345-kV buses. FE reported no evidence of a risk of cascading, but reported that some local load would be lost and generation redispatch would be needed to alleviate some thermal overloads.

ECAR and Organizational Independence

ECAR was established in 1967 as a regional reliability council, to "augment the reliability of the members' electricity supply systems through coordination of the planning and operation of the members' generation and transmission facilities."[a] ECAR's membership includes 29 major electricity suppliers serving more than 36 million people.

ECAR's annual budget for 2003 was $5.15 million (U.S.), including $1.775 million (U.S.) paid to fund NERC.[b] These costs are funded by its members in a formula that reflects megawatts generated, megawatt load served, and miles of high voltage lines. AEP, ECAR's largest member, pays about 15% of total ECAR expenses; FirstEnergy pays approximately 8 to 10%.[c]

Utilities "whose generation and transmission have an impact on the reliability of the interconnected electric systems" of the region are full ECAR members, while small utilities, independent power producers, and marketers can be associate members.[d] Its Executive Board has 22 seats, one for each full member utility or major supplier (including every control area operator in ECAR). Associate members do not have voting rights, either on the Board or on the technical committees which do all the work and policy-setting for the ECAR region.

All of the policy and technical decisions for ECAR, including all interpretations of NERC guidelines, policies, and standards within ECAR, are developed by committees (called "panels"), staffed by representatives from the ECAR member companies. Work allocation and leadership within ECAR are provided by the Board, the Coordination Review Committee, and the Market Interface Committee.

ECAR has a staff of 18 full-time employees, headquartered in Akron, Ohio. The staff provides engineering analysis and support to the various committees and working groups. Ohio Edison, a FirstEnergy subsidiary, administers salary, benefits, and accounting services for ECAR. ECAR employees automatically become part of Ohio Edison's (FirstEnergy's) 401(k) retirement plan; they receive FE stock as a matching share to employee 401(k) investments and can purchase FE stock as well. Neither ECAR staff nor board members are required to divest stock holdings in ECAR member companies.[e] Despite the close link between FirstEnergy's financial health and the interest of ECAR's staff and management, the investigation team has found no evidence to suggest that ECAR staff favor FirstEnergy's interests relative to other members.

ECAR decisions appear to be dominated by the member control areas, which have consistently allowed the continuation of past practices within each control area to meet NERC requirements, rather than insisting on more stringent, consistent requirements for such matters as operating voltage criteria or planning studies. ECAR member representatives also staff the reliability council's audit program, measuring individual control area compliance against local standards and interpretations. It is difficult for an entity dominated by its members to find that the members' standards and practices are inadequate. But it should also be recognized that NERC's broadly worded and ambiguous standards have enabled and facilitated the lax interpretation of reliability requirements within ECAR over the years.

> **Recommendations**
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[a]ECAR "Executive Manager's Remarks," http://www.ecar.org.
[b]Interview with Brantley Eldridge, ECAR Executive Manager, March 10, 2004.
[c]Interview with Brantley Eldridge, ECAR Executive Manager, March 3, 2004.
[d]ECAR "executive Manager's Remarks," http://www.ecar.org.
[e]Interview with Brantley Eldridge, ECAR Executive Manager, March 3, 2004.

Model-Based Analysis of the State of the Regional Power System at 15:05 EDT, Before the Loss of FE's Harding-Chamberlin 345-kV Line

As the first step in modeling the August 14 blackout, the investigation team established a base case by creating a power flow simulation for the entire Eastern Interconnection and benchmarking it to recorded system conditions at 15:05 EDT on August 14. The team started with a projected summer 2003 power flow case for the Eastern Interconnection developed in the spring of 2003 by the Regional Reliability Councils to establish guidelines for safe operations for the coming summer. The level of detail involved in this region-wide power flow case far exceeds that normally considered by individual control areas and reliability coordinators. It consists of a detailed representation of more than 43,000 buses, 57,600 transmission lines, and all major generating stations across the northern U.S. and eastern Canada. The team revised the summer power flow case to match recorded generation, demand, and power interchange levels among control areas at 15:05 EDT 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. Thousands of hours of effort were required to benchmark the model satisfactorily to observed conditions at 15:05 EDT.

Once the base case was benchmarked, the team ran a contingency analysis that considered more than 800 possible events—including the loss of the Harding-Chamberlin 345-kV line—as points of departure from the 15:05 EDT case. None of these contingencies resulted in a violation of a transmission line loading or bus voltage limit prior to the trip of FE's Harding-Chamberlin 345-kV line. That is, according to these simulations, the system at 15:05 EDT was capable of safe operation following the occurrence of any of the tested contingencies. From an electrical standpoint, therefore, *before* 15:05 EDT the Eastern Interconnection was being operated within all established limits and in full compliance with NERC's operating policies. However, *after* loss of the Harding-Chamberlin 345-kV line, the system would have exceeded emergency ratings immediately on several lines for two of the contingencies studied—in other words, it would no longer be operating in compliance with NERC Operating Policy A.2 because it could not be brought back into a secure operating condition within 30 minutes.

Perry Nuclear Plant as a First Contingency

Investigation team modeling demonstrates that the Perry nuclear unit (1,255 MW near Lake Erie) is critical to the voltage stability of the Cleveland-Akron area in general and particularly on August 14. The modeling reveals that had Perry tripped before 15:05 EDT, voltage levels at key FirstEnergy buses would have fallen close to 93% with only a 150 MW of area load margin (2% of the Cleveland-Akron area load); but had Perry been lost after the Harding-Chamberlin line went down at 15:05 EDT, the Cleveland-Akron area would have been close to voltage collapse.

Cause 1
Inadequate System Understanding

Perry and Eastlake 5 together have a combined real power capability of 1,852 MW and reactive capability of 930 MVAr. If one of these units is lost, it is necessary to immediately replace the lost generation with MW and MVAr imports (although reactive power does not travel far under heavy loading); without quick-start generation or spinning reserves or dynamic reactive reserves inside the Cleveland-Akron area, system security may be jeopardized. On August 14, as noted previously, there were no significant spinning reserves remaining within the Cleveland-Akron area following the loss of Eastlake 5 at 13:31 EDT. If Perry had been lost FE would have been unable to meet the 30-minute security adjustment requirement of NERC's Operating Policy 2, without the ability to shed load quickly. The loss of Eastlake 5 followed by the loss of Perry are contingencies that should be assessed in the operations planning timeframe, to develop measures to readjust the system between contingencies. Since FirstEnergy did not conduct such contingency analysis planning and develop these advance measures, it was in violation of NERC Planning Standard 1A, Category C3.

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This operating condition is not news. Historically, the loss of Perry at full output has been recognized as FE's most critical single contingency for the Cleveland Electric Illuminating area, as documented by FE's 1998 Summer Import Capability study. Perry's MW and MVAr total output capability exceeded the import capability of any of the critical 345-kV circuits into the Cleveland-Akron area after the loss of Eastlake 5 at 13:31 EDT. This

means that if the Perry plant had been lost on August 14 after Eastlake 5 went down—or on many other days with similar loads and outages—it would have been difficult or impossible for FE operators to adjust the system within 30 minutes to prepare for the next critical contingency, as required by NERC Operating Policy A.2. In real-time operations, operators would have to calculate operating limits and prepare to use the last resort of manually shedding large blocks of load before the second contingency, or immediately after it if automatic load-shedding is available.

Cause 1
Inadequate System Understanding

The investigation team could not find FirstEnergy contingency plans or operational procedures for operators to manage the FirstEnergy control area and protect the Cleveland-Akron area from the unexpected loss of the Perry plant.

To examine the impact of this worst contingency on the Cleveland-Akron area on August 14, Figure 4.9 shows the V-Q curves for key buses in the Cleveland-Akron area at 15:05 EDT, before and after the loss of the Harding-Chamberlin line. The curves on the left look at the impact of the loss of Perry

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before the Harding-Chamberlin trip, while the curves on the right show the impact had the nuclear plant been lost after Harding-Chamberlin went out of service. Had Perry gone down *before* the Harding-Chamberlin outage, reactive margins at key FE buses would have been minimal (with the tightest margin at the Harding bus, read along the Y-axis) and the critical voltage (the point before voltage collapse, read along the X-axis) at

Figure 4.9. Loss of the Perry Unit Hurts Critical Voltages and Reactive Reserves: V-Q Analyses
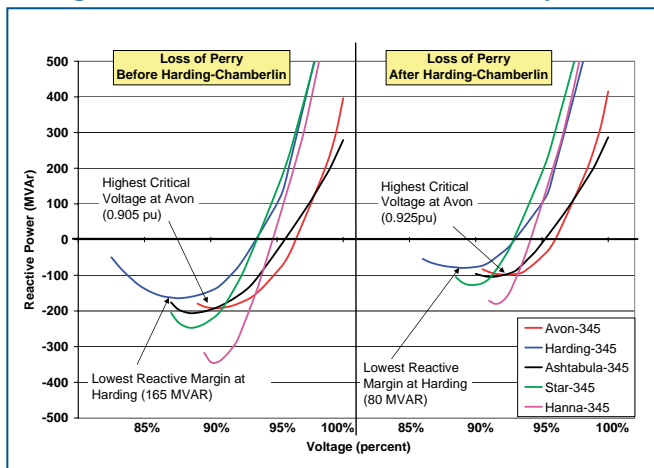
the Avon bus would have risen to 90.5%—uncomfortably close to the limits which FE considered as an acceptable operating range. But had the Perry unit gone off-line *after* Harding-Chamberlin, reactive margins at all these buses would have been even tighter (with only 60 MVAr at the Harding bus), and critical voltage at Avon would have risen to 92.5%, worse than FE's 90% minimum acceptable voltage. The system at this point would be very close to voltage instability. If the first line outage on August 14, 2003, had been at Hanna-Juniper rather than at Harding-Chamberlin, the FirstEnergy system could not have withstood the loss of the Perry plant.

Cause 1
Inadequate System Understanding

The above analysis assumed load levels consistent with August 14. But temperatures were not particularly high that day and loads were nowhere near FE's historic load level of 13,229 MW for the control area (in August 2002). Therefore the investigation team looked at what might have happened in the Cleveland-Akron area had loads neared the historic peak—approximately 625 MW higher than the 6,715 MW peak load in the Cleveland-Akron area in 2003. Figure 4.10 uses P-V analysis to show the impact of increased load levels on voltages at the Star bus with and without the Perry unit before the loss of the Harding-Chamberlin line at 15:05 EDT. The top line shows that with the Perry plant available, local load could have increased by 625 MW and voltage at Star would have remained above 95%. But the bottom line, simulating the loss of Perry, indicates that load could only have increased by about 150 MW before voltage at Star would have become unsolvable, indicating no voltage stability margin and depending on load dynamics, possible voltage collapse.

The above analyses indicate that the Cleveland-Akron area was highly vulnerable on the afternoon of August 14. Although the system was compliant with NERC Operating Policy 2A.1 for single contingency reliability before the loss of the Harding-Chamberlin line at 15:05 EDT, had FE lost the Perry plant its system would have neared voltage instability or could have gone into a full voltage collapse immediately if the Cleveland-Akron area load were 150 MW higher. It is worth noting that this could have happened on August 14—at 13:43 EDT that afternoon, the Perry plant operator called the control area operator to warn about low voltages. At 15:36:51 EDT the Perry plant operator called FirstEnergy's system control center to ask about voltage spikes at the plant's main

transformer.[14] At 15:42:49 EDT the Perry operator called the FirstEnergy operator to say, "I'm still getting a lot of voltage spikes and swings on the generator . . . . I'm taking field volts pretty close to where I'll trip the turbine off."[15]

System Frequency

Assuming stable conditions, the system frequency is the same across an interconnected grid at any particular moment. System frequency will vary from moment to moment, however, depending on the second-to-second balance between aggregate generation and aggregate demand across the interconnection. System frequency is monitored on a continuous basis.

There were no significant or unusual frequency oscillations in the Eastern Interconnection on August 14 prior to 16:09 EDT compared to prior days, and frequency was well within the bounds of safe operating practices. System frequency variation was not a cause or precursor of the initiation of the blackout. But once the cascade began, the large frequency swings that occurred early on became a principal means by which the blackout spread across a wide area.

Figure 4.11 shows Eastern Interconnection frequency on August 14, 2003. Frequency declines or increases from a mismatch between generation and load on the order of about 3,200 MW per 0.1 Hertz (alternatively, a change in load or generation of 1,000 MW would cause a frequency

change of about ±0.031 Hz). Significant frequency excursions reflect large changes in load relative to generation and could cause unscheduled flows between control areas and even, in the extreme, cause automatic under-frequency load-shedding or automatic generator trips.

The investigation team examined Eastern Interconnection frequency and Area Control Error (ACE) for August 14, 2003 and the entire month of August, looking for patterns and anomalies. Extensive analysis using Fast Fourier Transforms (described in the NERC Technical Report) revealed no unusual variations. Rather, transforms using various time samples of average frequency (from 1 hour to 6 seconds in length) indicate instead that the Eastern Interconnection exhibits regular deviations.[16]

The largest deviations in frequency occur at regular intervals. These intervals reflect interchange

Figure 4.10. Impact of Perry Unit Outage on Cleveland-Akron Area Voltage Stability
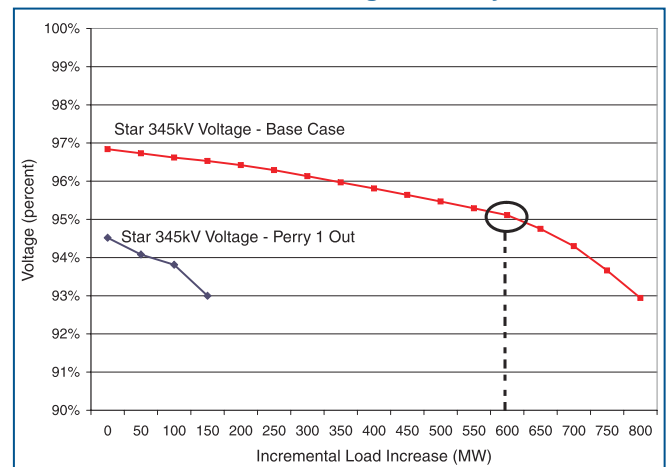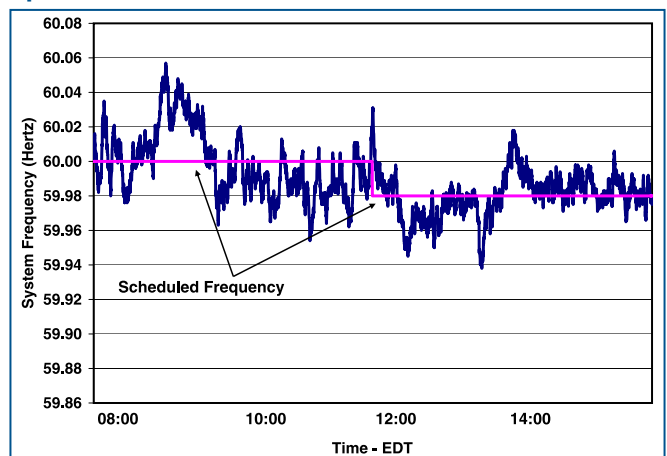

Figure 4.11. Frequency on August 14, 2003, up to 16:09 EDT

> ### Frequency Management
>
> Each control area is responsible for maintaining a balance between its generation and demand. If persistent under-frequency occurs, at least one control area somewhere is "leaning on the grid," meaning that it is taking unscheduled electricity from the grid, which both depresses system frequency and creates unscheduled power flows. In practice, minor deviations at the control area level are routine; it is very difficult to maintain an exact balance between generation and demand. Accordingly, NERC has established operating rules that specify maximum permissible deviations, and focus on prohibiting persistent deviations, but not instantaneous ones. NERC monitors the performance of control areas through specific measures of control performance that gauge how accurately each control area matches its load and generation.

schedule changes at the peak to off-peak schedule changes (06:00 to 07:00 and 21:00 to 22:00, as shown in Figure 4.12) and on regular hourly and half-hour schedule changes as power plants ramp up and down to serve scheduled purchases and interchanges. Frequency tends to run high in the early part of the day because extra generation capacity is committed and waiting to be dispatched for the afternoon peak, and then runs lower in the afternoon as load rises relative to available generation and spinning reserve. The investigation team concluded that frequency data collection and frequency management in the Eastern Interconnection should be improved, but that frequency oscillations before 16:09 EDT on August 14 had no effect on the blackout.

Conclusion

Determining that the system was in a reliable operational state at 15:05 EDT is extremely significant for understanding the causes of the blackout. It means that none of the electrical conditions on the system before 15:05 EDT was a cause of the blackout. This eliminates low voltages earlier in the day or on prior days, the unavailability of individual generators or transmission lines (either individually or in combination with one another), high power flows to Canada, unusual system frequencies, and many other issues as direct, principal or sole causes of the blackout.

Although FirstEnergy's system was technically in secure electrical condition before 15:05 EDT, it was still highly vulnerable, because some of its assumptions and limits were not accurate for safe operating criteria. Analysis of Cleveland-Akron area voltages and reactive margins shows that FirstEnergy was operating that system on the very edge of NERC operational reliability standards, and that it could have been compromised by a number of potentially disruptive scenarios that were foreseeable by thorough planning and operations studies. A system with this little reactive margin would leave little room for adjustment, with few relief actions available to operators in the face of single or multiple contingencies. As the next chapter will show, the vulnerability created by inadequate system planning and understanding was exacerbated because the FirstEnergy operators were not adequately trained or prepared to recognize and deal with emergency situations.

Figure 4.12. Hourly Deviations in Eastern Interconnection Frequency for the Month of August 2003
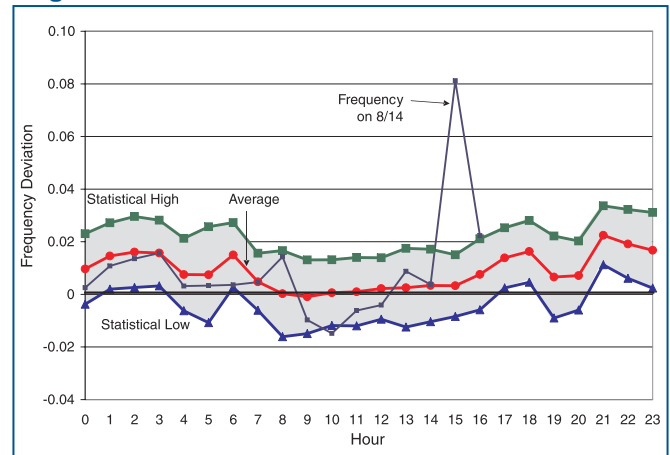
Endnotes

[1] FE transcripts, Channel 14, 13:33:44.

[2] FE transcripts, Channel 14 at 13:21:05; channel 3 at 13:41:54; 15:30:36.

[3] "ECAR Investigation of August 14, 2003 Blackout by Major System Disturbance Analysis Task Force, Recommendations Report," page 6.

[4] Transmission operator at FE requested the restoration of the Avon Substation capacitor bank #2. Example at Channel 3, 13:33:40. However, no additional capacitors were available.

[5] From 13:13 through 13:28, reliability operator at FE called nine plant operators to request additional voltage support. Examples at Channel 16, 13:13:18, 13:15:49, 13:16:44, 13:20:44, 13:22:07, 13:23:24, 13:24:38, 13:26:04, 13:28:40.

[6] DOE/NERC fact-finding meeting, September 2003, statement by Mr. Steve Morgan (FE), PR0890803, lines 5-23.

[7] See 72 FERC 61,040, the order issued for FERC dockets EL 94-75-000 and EL 94-80-000, for details of this incident.

[8] Testimony by Stanley Szwed, Vice President of Engineering and Planning, Centerior Service Company (Cleveland Electric Illuminating Company and Toledo Edison), FERC docket EL 94-75-000, February 22, 1996.

[9] Presentation notes for January 10, 2003 meeting between AEP and FirstEnergy, and meeting summary notes by Paul Johnson, AEP Manager, East Bulk Transmission Planning, January 10, 2003.

[10] "Talking Points" for May 21, 2003 meeting between AEP and FirstEnergy, prepared by AEP.

[11] Memo, "Summary of AEP/FE Meeting on 5/21/03," by Scott P. Lockwood, AEP, May 29, 2003.

[12] *Ibid.*

[13] Testimony by Stanley Szwed, Vice President of Engineering and Planning, Centerior Service Company (Cleveland Electric Illuminating Company and Toledo Edison), FERC docket EL 94-75-000, February 22, 1996.

[14] FE transcript, Channel 8.

[15] FE transcript, Channel 8.

[16] See NERC Blackout Investigation Technical Reports, to be released in 2004.

5. How and Why the Blackout Began in Ohio

Summary

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

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

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

and generating units automatically tripped by protective relay action to avoid physical damage.

Chapter Organization

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

- ◆ **Phase 1:** A normal afternoon degrades
- ◆ **Phase 2:** FE's computer failures
- ◆ **Phase 3:** Three FE 345-kV transmission line failures and many phone calls
- ◆ **Phase 4:** The collapse of the FE 138-kV system and the loss of the Sammis-Star line.
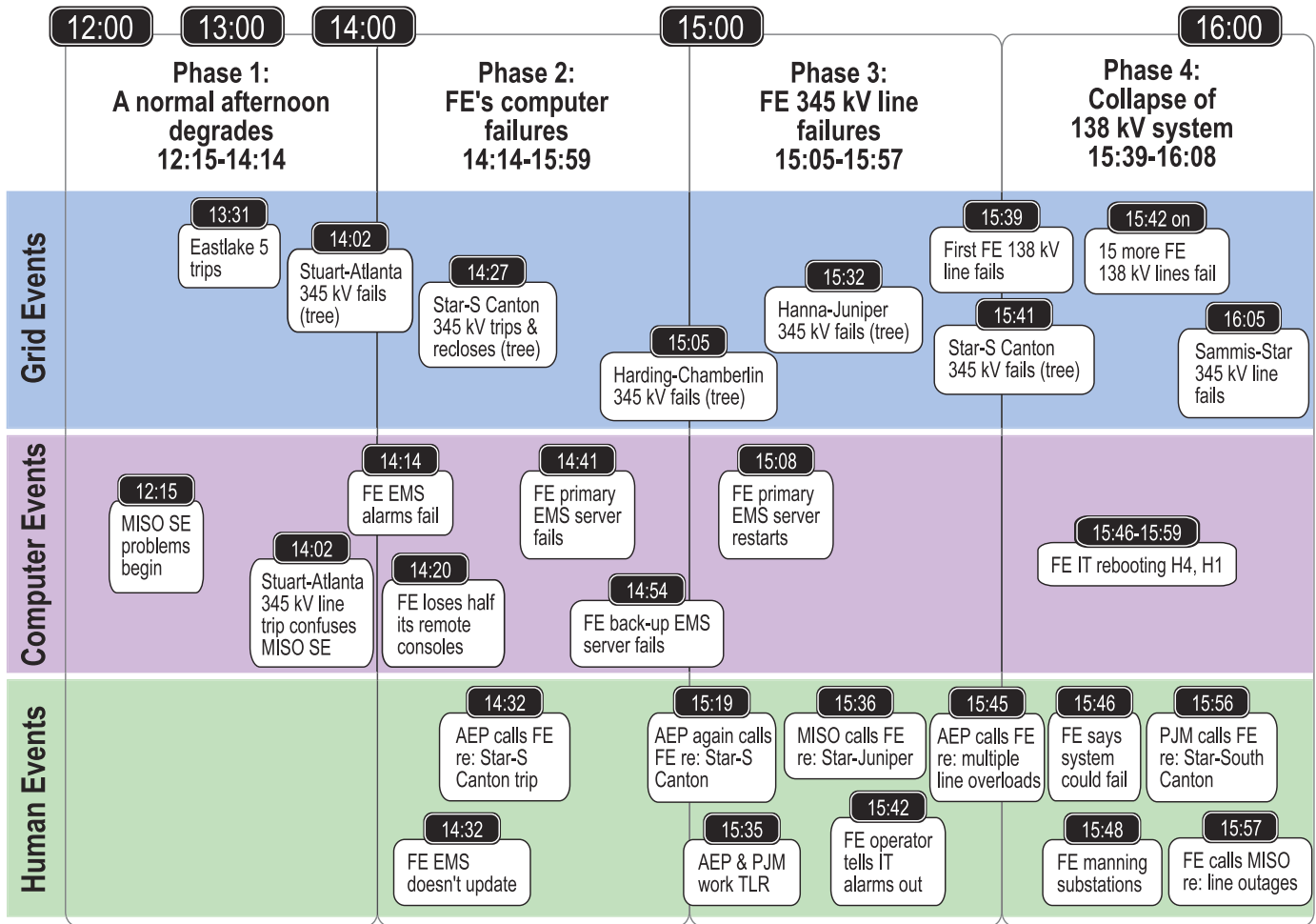
Key events within each phase are summarized in Figure 5.1, a timeline of major events in the origin of the blackout in Ohio. The discussion that follows highlights and explains these significant events within each phase and explains how the events were related to one another and to the cascade. Specific causes of the blackout and associated recommendations are identified by icons.

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

Overview of This Phase

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

Figure 5.1. Timeline: Start of the Blackout in Ohio

12:00	13:00	14:00		15:00		16:00
Phase 1: A normal afternoon degrades 12:15-14:14		**Phase 2:** FE's computer failures 14:14-15:59		**Phase 3:** FE 345 kV line failures 15:05-15:57		**Phase 4:** Collapse of 138 kV system 15:39-16:08

Grid Events
- 13:31 — Eastlake 5 trips
- 14:02 — Stuart-Atlanta 345 kV fails (tree)
- 14:27 — Star-S Canton 345 kV trips & recloses (tree)
- 15:05 — Harding-Chamberlin 345 kV fails (tree)
- 15:32 — Hanna-Juniper 345 kV fails (tree)
- 15:39 — First FE 138 kV line fails
- 15:41 — Star-S Canton 345 kV fails (tree)
- 15:42 on — 15 more FE 138 kV lines fail
- 16:05 — Sammis-Star 345 kV line fails

Computer Events
- 12:15 — MISO SE problems begin
- 14:02 — Stuart-Atlanta 345 kV line trip confuses MISO SE
- 14:14 — FE EMS alarms fail
- 14:20 — FE loses half its remote consoles
- 14:41 — FE primary EMS server fails
- 14:54 — FE back-up EMS server fails
- 15:08 — FE primary EMS server restarts
- 15:46-15:59 — FE IT rebooting H4, H1

Human Events
- 14:32 — AEP calls FE re: Star-S Canton trip
- 14:32 — FE EMS doesn't update
- 15:19 — AEP again calls FE re: Star-S Canton
- 15:35 — AEP & PJM work TLR
- 15:36 — MISO calls FE re: Star-Juniper
- 15:42 — FE operator tells IT alarms out
- 15:45 — AEP calls FE re: multiple line overloads
- 15:46 — FE says system could fail
- 15:48 — FE manning substations
- 15:56 — PJM calls FE re: Star-South Canton
- 15:57 — FE calls MISO re: line outages

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

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

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

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

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

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Energy Management System (EMS) and Decision Support Tools

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

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

Field RTUs, installed at generation plants and substations, are combination data gathering and device control units. They gather and provide information of interest to system operators, such as the status of a breaker (switch), the voltage on a line or the amount of real and reactive power being produced by a generator, and execute control operations such as opening or closing a breaker. Telecommunications facilities, such as telephone lines or microwave radio channels, are provided for the field RTUs so they can communicate with one or more SCADA Master Stations or, less commonly, with each other.
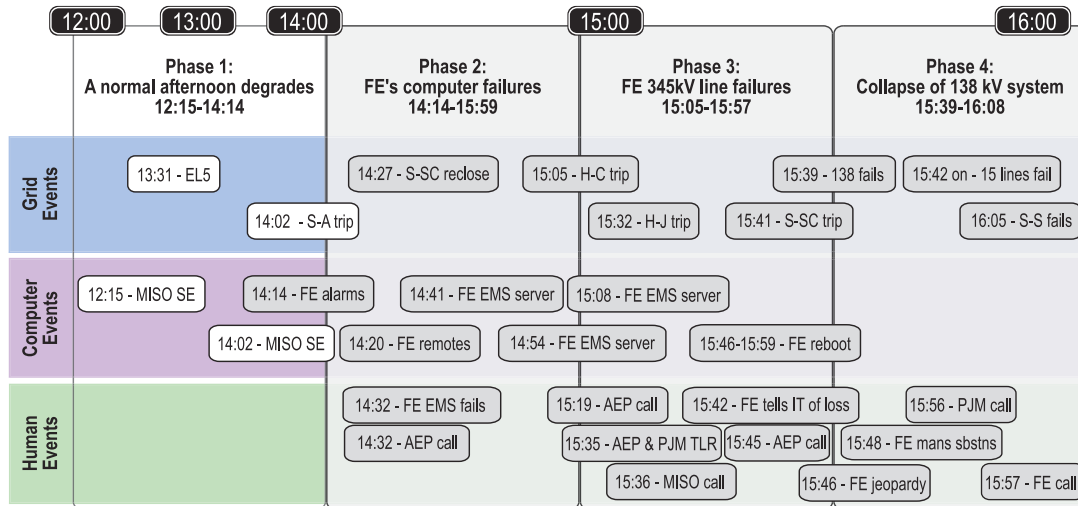
Master stations are the pieces of the SCADA system that initiate a cycle of data gathering from the field RTUs over the communications facilities, with time cycles ranging from every few seconds to as long as several minutes. In many power systems, Master Stations are fully integrated into the control room, serving as the direct interface to the Energy Management System (EMS), receiving incoming data from the field RTUs and relaying control operations commands to the field devices for execution.

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

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

Figure 5.2. Timeline Phase 1

	Phase 1: A normal afternoon degrades 12:15-14:14	Phase 2: FE's computer failures 14:14-15:59	Phase 3: FE 345 kV line failures 15:05-15:57	Phase 4: Collapse of 138 kV system 15:39-16:08
Grid Events	13:31 - EL5	14:27 - S-SC reclose / 14:02 - S-A trip	15:05 - H-C trip / 15:32 - H-J trip / 15:41 - S-SC trip	15:39 - 138 fails / 15:42 on - 15 lines fail / 16:05 - S-S fails
Computer Events	12:15 - MISO SE / 14:14 - FE alarms / 14:02 - MISO SE	14:41 - FE EMS server / 14:20 - FE remotes / 14:54 - FE EMS server	15:08 - FE EMS server	15:46-15:59 - FE reboot
Human Events		14:32 - FE EMS fails / 14:32 - AEP call	15:19 - AEP call / 15:35 - AEP & PJM TLR / 15:36 - MISO call / 15:42 - FE tells IT of loss / 15:45 - AEP call / 15:46 - FE jeopardy	15:56 - PJM call / 15:48 - FE mans sbstns / 15:57 - FE call

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

Key Phase 1 Events

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Figure 5.3. Eastlake Unit 5
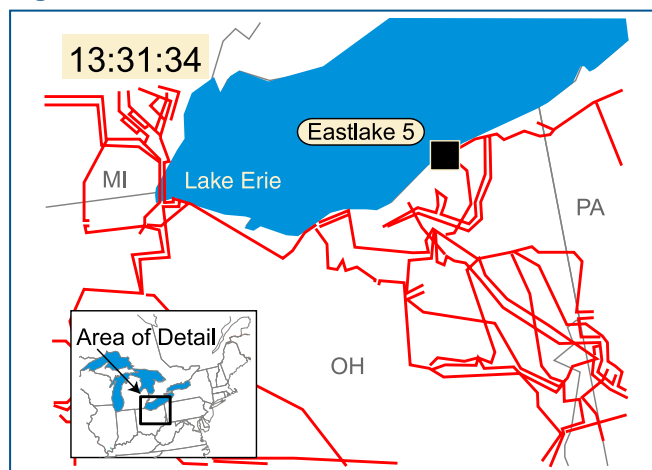
secure state at 15:05 EDT, and that operator action was needed to remedy the situation.

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

Cause 1
Inadequate System Understanding

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

Data Exchanged for Operational Reliability

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

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

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

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

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

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

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

Overview of This Phase

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

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Data Exchanged for Operational Reliability (Continued)

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

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

SDX: The IDC depends on element status information, exchanged over the NERC System Data Exchange (SDX) system, to keep the system topology current in its powerflow model of the Eastern Interconnection. The SDX distributes generation and transmission outage information to all operators, as well as demand and operating reserve projections for the next 48 hours. These data are used to update the IDC model, which is used to calculate the impact of power transfers across the system on individual transmission system elements. There is no current requirement for how quickly asset owners must report changes in element status (such as a line outage) to the SDX—some entities update it with facility status only once a day, while others submit new information immediately after an event occurs. NERC is now developing a requirement for regular information update submittals that is scheduled to take effect in the summer of 2004.
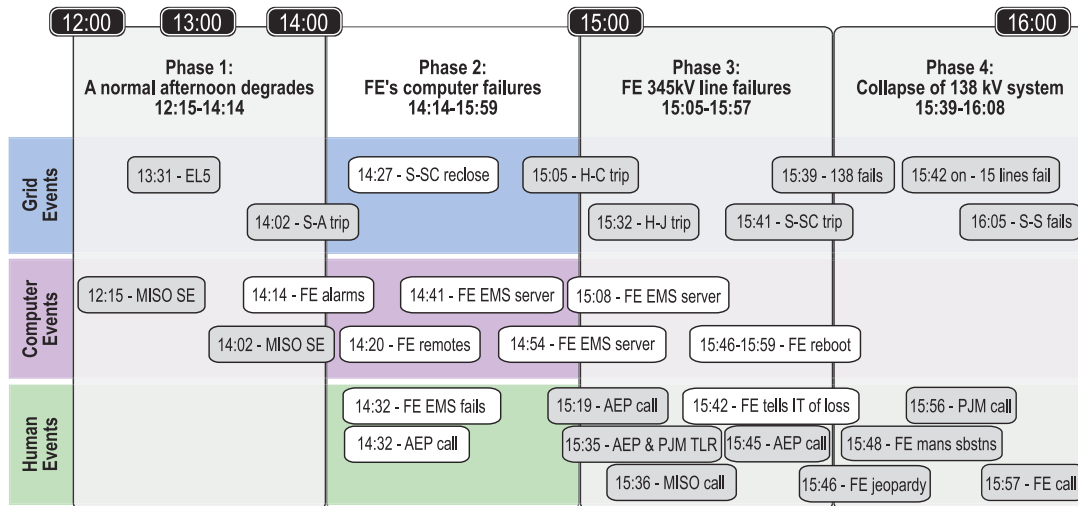
SDX data are used by some control centers to keep their topology up-to-date for areas of the interconnection that are not observable through direct telemetry or ICCP data. A number of transmission providers also use these data to update their transmission models for short-term

determination of available transmission capability (ATC).

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

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

Figure 5.4. Timeline Phase 2

Figure 5.4. Timeline Phase 2

	12:00	13:00	14:00	15:00	16:00
	Phase 1: A normal afternoon degrades 12:15-14:14		Phase 2: FE's computer failures 14:14-15:59	Phase 3: FE 345kV line failures 15:05-15:57	Phase 4: Collapse of 138 kV system 15:39-16:08

Grid Events: 13:31 - EL5 · 14:27 - S-SC reclose · 15:05 - H-C trip · 15:39 - 138 fails · 15:42 on - 15 lines fail · 14:02 - S-A trip · 15:32 - H-J trip · 15:41 - S-SC trip · 16:05 - S-S fails

Computer Events: 12:15 - MISO SE · 14:14 - FE alarms · 14:41 - FE EMS server · 15:08 - FE EMS server · 14:02 - MISO SE · 14:20 - FE remotes · 14:54 - FE EMS server · 15:46-15:59 - FE reboot

Human Events: 14:32 - FE EMS fails · 15:19 - AEP call · 15:42 - FE tells IT of loss · 15:56 - PJM call · 14:32 - AEP call · 15:35 - AEP & PJM TLR · 15:45 - AEP call · 15:48 - FE mans sbstns · 15:36 - MISO call · 15:46 - FE jeopardy · 15:57 - FE call

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

Key Events in This Phase

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

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

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

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

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

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

Failure of FE's Alarm System

Cause 2
Inadequate Situational Awareness

FE's computer SCADA alarm and logging software failed sometime shortly after 14:14 EDT (the last time that a valid alarm came in),

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

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

In the same way that an alarm system can inform operators about the failure of key grid facilities, it

can also be set up to alarm them if the alarm system itself fails to perform properly. FE's EMS did not have such a notification system.

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

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

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Alarms

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

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

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

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

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

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

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

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

> **Recommendation 22, page 159**

Cause 2
Inadequate Situational Awareness

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

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

> **Recommendation 19, page 156**

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

> **Recommendation 22, page 159**

Cause 2
Inadequate Situational Awareness

The concurrent loss of the EMS servers also caused the failure of FE's strip chart function. There are many strip charts in the FE Reliability Operator control room driven by the EMS computers, showing a variety

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

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

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

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Who Saw What?

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

Midwest ISO (MISO), reliability coordinator for FE

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

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

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

AEP

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

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

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

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

<div style="float:right">**Recommendation 33, page 164**</div>

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

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

<div style="float:right">**Recommendation 26, page 161**</div>

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

Cause 2
Inadequate Situational Awareness

Although FE's IT staff would have been aware that concurrent loss of its servers would mean the loss of alarm processing on the EMS, the investigation team has found no indication that the IT staff informed the control

room staff either when they began work on the servers at 14:54 EDT, or when they completed the primary server restart at 15:08 EDT. At 15:42 EDT, the IT staff were first told of the alarm problem by a control room operator; FE has stated to investigators that their IT staff had been unaware before then that the alarm processing sub-system of the EMS was not working.

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

Cause 2
Inadequate Situational Awareness

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

<div style="float:right">**Recommendations 19, page 156; 26, page 161**</div>

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

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

had changed due to un-scheduled equipment outages that might affect other control areas.

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

Overview of This Phase

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

Key Phase 3 Events

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

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

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

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

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

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

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

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

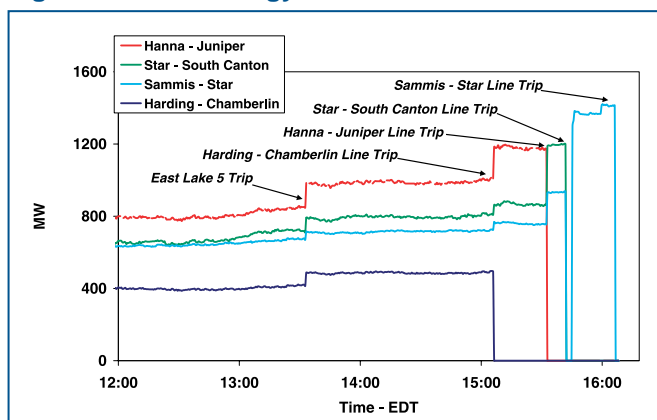## Figure 5.5. FirstEnergy 345-kV Line Flows

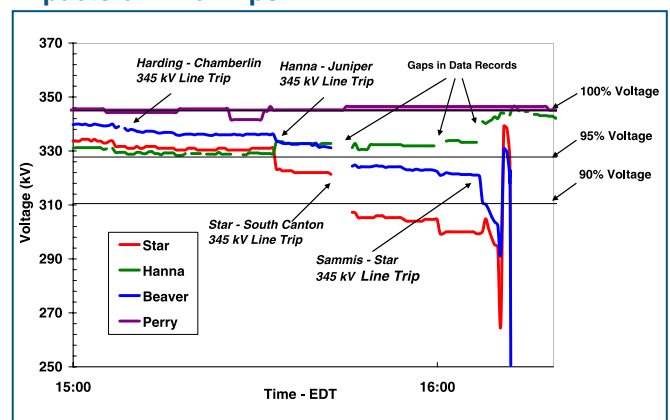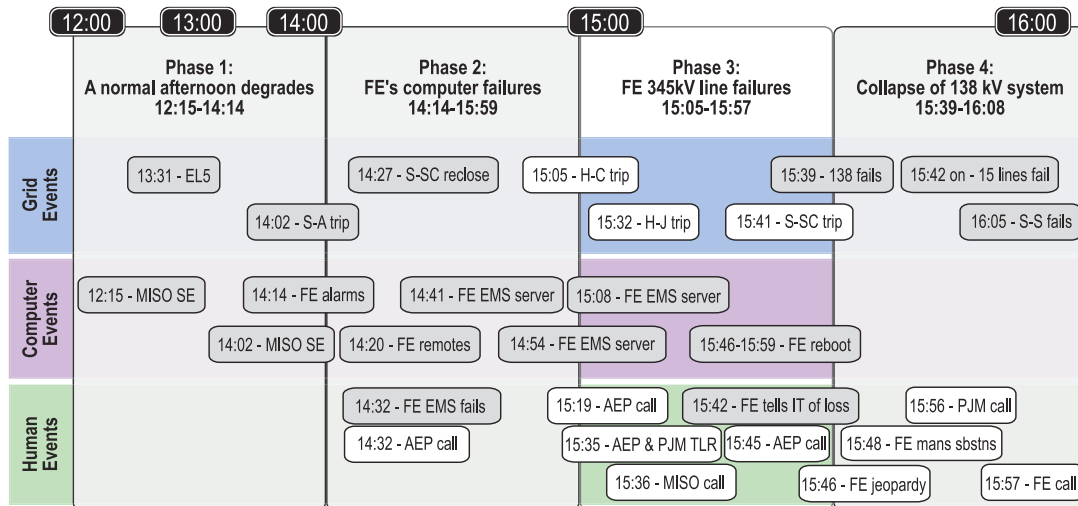## Figure 5.6. Voltages on FirstEnergy's 345-kV Lines: Impacts of Line Trips

Figure 5.7. Timeline Phase 3

Phase 1: A normal afternoon degrades 12:15-14:14
Phase 2: FE's computer failures 14:14-15:59
Phase 3: FE 345kV line failures 15:05-15:57
Phase 4: Collapse of 138 kV system 15:39-16:08

Grid Events:
- 13:31 - EL5
- 14:02 - S-A trip
- 14:27 - S-SC reclose
- 15:05 - H-C trip
- 15:32 - H-J trip
- 15:39 - 138 fails
- 15:41 - S-SC trip
- 15:42 on - 15 lines fail
- 16:05 - S-S fails

Computer Events:
- 12:15 - MISO SE
- 14:02 - MISO SE
- 14:14 - FE alarms
- 14:20 - FE remotes
- 14:41 - FE EMS server
- 14:54 - FE EMS server
- 15:08 - FE EMS server
- 15:46-15:59 - FE reboot

Human Events:
- 14:32 - FE EMS fails
- 14:32 - AEP call
- 15:19 - AEP call
- 15:35 - AEP & PJM TLR
- 15:36 - MISO call
- 15:42 - FE tells IT of loss
- 15:45 - AEP call
- 15:46 - FE jeopardy
- 15:48 - FE mans sbstns
- 15:56 - PJM call
- 15:57 - FE call

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

Cause 3
Inadequate Tree Trimming

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

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

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

Line Ratings

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

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

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

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

Recommendations
16, page 154; 27, page 162

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

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

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Utility Vegetation Management: When Trees and Lines Contact

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

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

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

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

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

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

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

Cause 3
Inadequate Tree Trimming

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

Recommendations
16, page 154; 27, page 162

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

Cause 2
Inadequate Situational Awareness

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

Recommendation
22, page 159

Cause 4
Inadequate RC Diagnostic Support

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

Figure 5.8. Harding-Chamberlin 345-kV Line
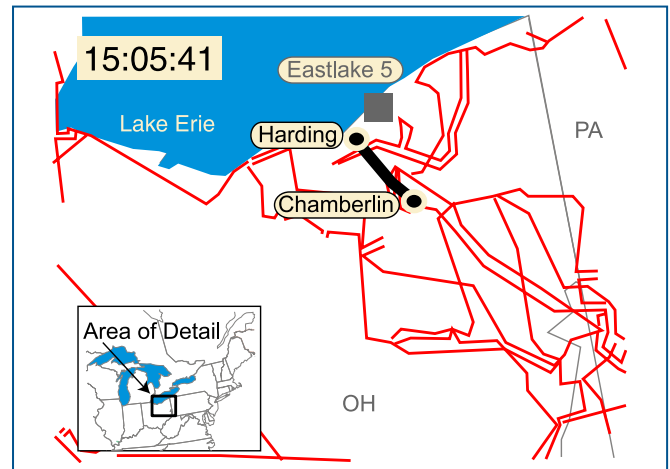
SCADA input of the line's status change, this was presented to MISO operators as breaker status changes rather than a line failure. Because their EMS system topology processor had not yet been linked to recognize line failures, it did not connect the breaker information to the loss of a transmission line. Thus, MISO's operators did not recognize the Harding-Chamberlin trip as a significant contingency event and could not advise FE regarding the event or its consequences. Further, without its state estimator and associated contingency analyses, MISO was unable to identify potential overloads that would occur due to various line or equipment outages. Accordingly, when the Harding-Chamberlin 345-kV line tripped at 15:05 EDT, the state estimator did not produce results and could not predict an overload if the Hanna-Juniper 345-kV line were to fail.

Recommendation
30, page 163

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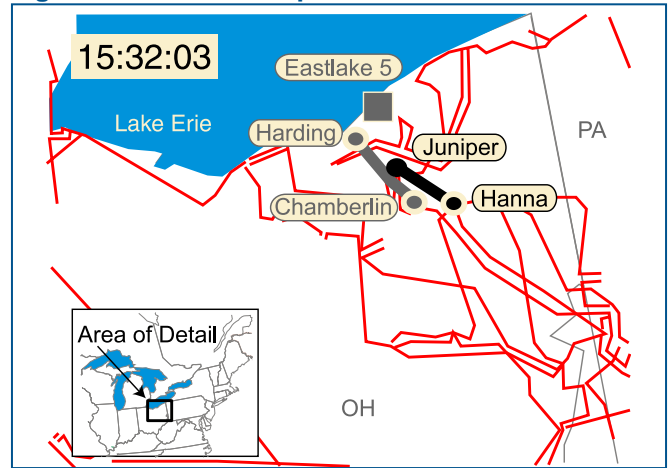
Cause 3
Inadequate Tree Trimming

At 15:32:03 EDT the Hanna-Juniper line (Figure 5.9) tripped and locked out. A tree-trimming crew was working nearby and observed the tree/line contact. The tree contact occurred on the south phase, which is lower than the center phase due to construction design. Although little evidence remained of the tree during the field team's visit in October, the team observed a tree stump 14 inches (35.5 cm) in diameter at its ground line and talked to an individual who witnessed the contact on August 14.[26] Photographs clearly indicate that the tree was of excessive height (Figure 5.10). Surrounding trees were 18 inches (45.7 cm) in diameter at ground line and 60 feet (18.3 meters) in

height (not near lines). Other sites at this location had numerous (at least 20) trees in this right-of-way.

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

Figure 5.9. Hanna-Juniper 345-kV Line

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

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

◆ Most tree growth occurs during the spring and summer months, so the later in the summer the taller the tree and the greater its potential to contact a nearby transmission line.

◆ As temperatures increase, customers use more air conditioning and load levels increase. Higher load levels increase flows on the transmission system, causing greater demands for both active power (MW) and reactive power (MVAr). Higher flow on a transmission line causes the line to heat up, and the hot line sags lower because the hot conductor metal expands. Most emergency line ratings are set to limit conductors' internal temperatures to no more than 100°C (212°F).

◆ As temperatures increase, ambient air temperatures provide less cooling for loaded transmission lines.

◆ Wind flows cool transmission lines by increasing the airflow of moving air across the line. On August 14 wind speeds at the Ohio Akron-Fulton airport averaged 5 knots (1.5 m/sec) at around 14:00 EDT, but by 15:00 EDT wind speeds had fallen to 2 knots (0.6 m/sec)—the wind speed commonly assumed in conductor design—or lower. With lower winds, the lines sagged further and closer to any tree limbs near the lines.

This combination of events on August 14 across much of Ohio and Indiana caused transmission lines to heat and sag. If a tree had grown into a power line's designed clearance area, then a tree/line contact was more likely, though not inevitable. An outage on one line would increase power flows on related lines, causing them to be loaded higher, heat further, and sag lower.
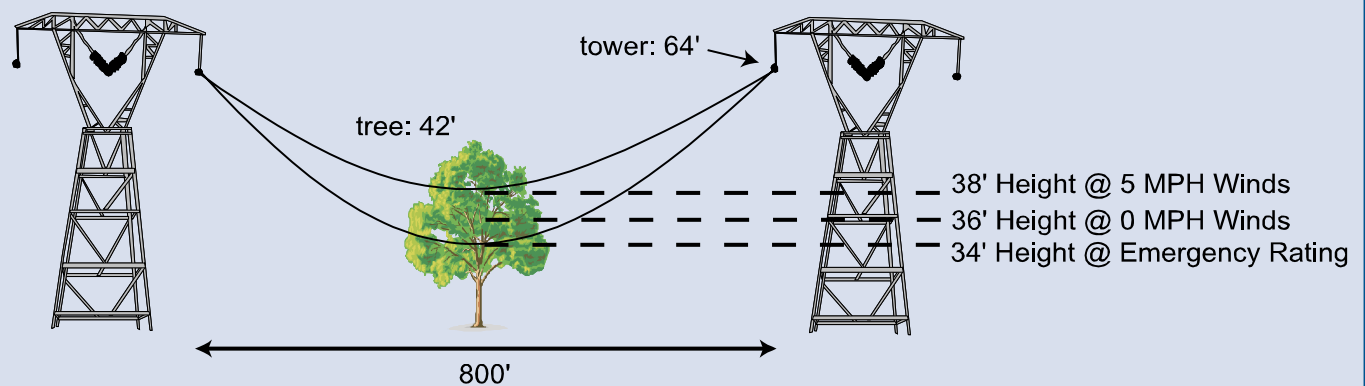
### 3D) AEP and PJM Begin Arranging a TLR for Star-South Canton: 15:35 EDT

Cause 4
Inadequate RC Diagnostic Support

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

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

Figure 5.10. Cause of the Hanna-Juniper Line Loss
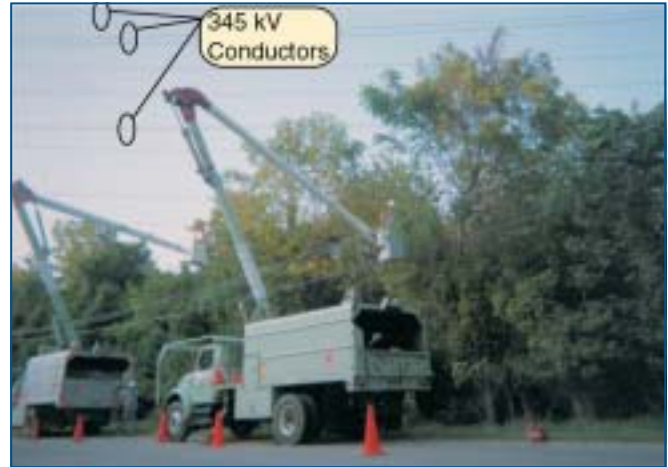
This August 14 photo shows the tree that caused the loss of the Hanna-Juniper line (tallest tree in photo). Other 345-kV conductors and shield wires can be seen in the background. Photo by Nelson Tree.

Handling Emergencies by Shedding Load and Arranging TLRs

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

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

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

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

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

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

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

> **Cause 2**
> Inadequate
> Situational
> Awareness

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

> **Cause 4**
> Inadequate
> RC Diagnostic
> Support

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

were not working properly, MISO's ability to recognize FE's evolving contingency situation was impaired.

> **Recommendations**
> 22, page 159; 30, page 163

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

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

> **Cause 3**
> Inadequate
> Tree
> Trimming

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

Figure 5.11. Star-South Canton 345-kV Line
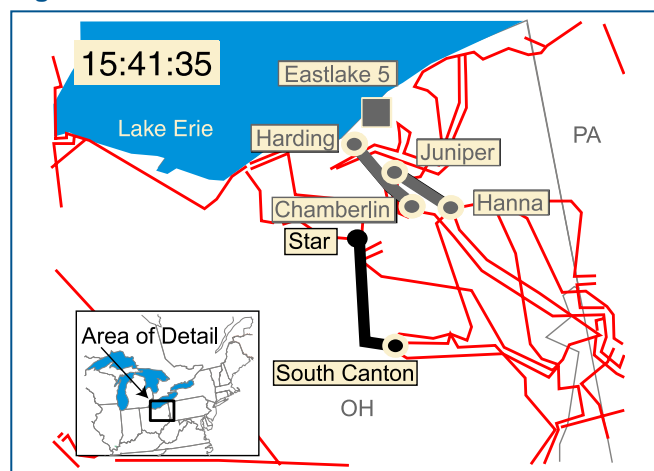
the area of the tree trunk was disturbed, discolored and broken up, a common indication of a higher magnitude fault or multiple faults. Analysis of another stump showed that a fourteen year-old tree had recently been removed from the middle of the right-of-way.[28]

> **Recommendations**
> **16, page 154; 27, page 162**

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

> **Cause 2**
> Inadequate Situational Awareness

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

> **Recommendation**
> **22, page159**

> **Cause 1**
> Inadequate System Understanding

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

> **Recommendations**
> **8, page 147; 21, page 158**

> **Cause 2**
> Inadequate Situational Awareness

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

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

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

Figure 5.12. Cumulative Effects of Sequential Outages on Remaining 345-kV Lines
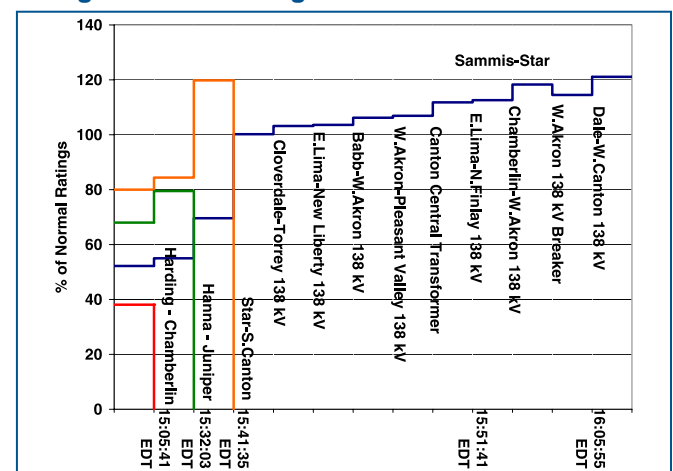
◆ The Hanna-Juniper and Harding-Juniper 345-kV lines, whose loadings would exceed emergency limits if the Perry generation unit (1,255 MW) were lost.

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

Phone Calls into the FE Control Room

Cause 2
Inadequate Situational Awareness

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

Recommendations
19, page 156; 26, page 161

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

Following the first trip of the Star-South Canton 345-kV line at 14:27 EDT, AEP called FE at 14:32 EDT to discuss the trip and reclose of the line. AEP was aware of breaker operations at their end (South Canton) and asked about operations at FE's Star end. FE indicated they had seen nothing at their end of the line, but AEP reiterated that the trip occurred at 14:27 EDT and that the South Canton breakers had reclosed successfully.[30] There was an internal FE conversation about the AEP

call at 14:51 EDT, expressing concern that they had not seen any indication of an operation, but lacking evidence within their control room, the FE operators did not pursue the issue.

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

At 15:35 EDT the FE control center received a call from the Mansfield 2 plant operator concerned about generator fault recorder triggers and excitation voltage spikes with an alarm for over-excitation, and a dispatcher called reporting a "bump" on their system. Soon after this call, FE's Reading, Pennsylvania control center called reporting that fault recorders in the Erie west and south areas had activated, wondering if something had happened in the Ashtabula-Perry area. The Perry nuclear plant operator called to report a "spike" on the unit's main transformer. When he went to look at the metering it was "still bouncing around pretty good. I've got it relay tripped up here . . . so I know something ain't right."[32]

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

Recommendation
22, page 159

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

At 15:42 EDT, FE's western transmission operator informed FE's IT staff that the EMS system functionality was compromised. "Nothing seems to be updating on the computers . . . . We've had people calling and reporting trips and nothing seems to be updating in the event summary . . . I think we've

got something seriously sick." This is the first evidence that a member of FE's control room staff recognized any aspect of their degraded EMS system. There is no indication that he informed any of the other operators at this moment. However, FE's IT staff discussed the subsequent EMS alarm corrective action with some control room staff shortly thereafter.

Also at 15:42 EDT, the Perry plant operator called back with more evidence of problems. "I'm still getting a lot of voltage spikes and swings on the generator . . . . I don't know how much longer we're going to survive."[35]

At 15:45 EDT, the tree trimming crew reported that they had witnessed a tree-caused fault on the Eastlake-Juniper 345-kV line; however, the actual fault was on the Hanna-Juniper 345-kV line in the same vicinity. This information added to the confusion in the FE control room, because the operator had indication of flow on the Eastlake-Juniper line.[36]

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

At 15:46 EDT the Perry plant operator called the FE control room a third time to say that the unit was close to tripping off: "It's not looking good . . . . We ain't going to be here much longer and you're going to have a bigger problem."[38]

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

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

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

Emergency Action

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

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

> **Recommendation 20, page 158**

Cause 2
Inadequate Situational Awareness

At the control area level, FE remained unaware of the precarious condition its system was in, with key lines out of service, degrading voltages, and severe overloads on their remaining lines. Transcripts show that FE operators were aware of falling voltages and customer problems after loss of the Hanna-Juniper 345-kV line (at 15:32 EDT). They called out personnel to staff substations because they did not think they could see them with their data gathering tools. They were also talking to customers. But there is no indication that FE's operators clearly identified their situation as a possible emergency until around 15:45 EDT when the shift

supervisor informed his manager that it looked as if they were losing the system; even then, although FE had grasped that its system was in trouble, it never officially declared that it was an emergency condition and that emergency or extraordinary action was needed.

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

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

Cause 2
Inadequate Situational Awareness

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

> **Recommendation**
> **26, page 161**

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

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

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

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

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

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

> **Recommendation**
> **20, page 158**

Cause 4
Inadequate RC Diagnostic Support

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

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

Figure 5.13. Timeline Phase 4

Figure 5.13. Timeline Phase 4
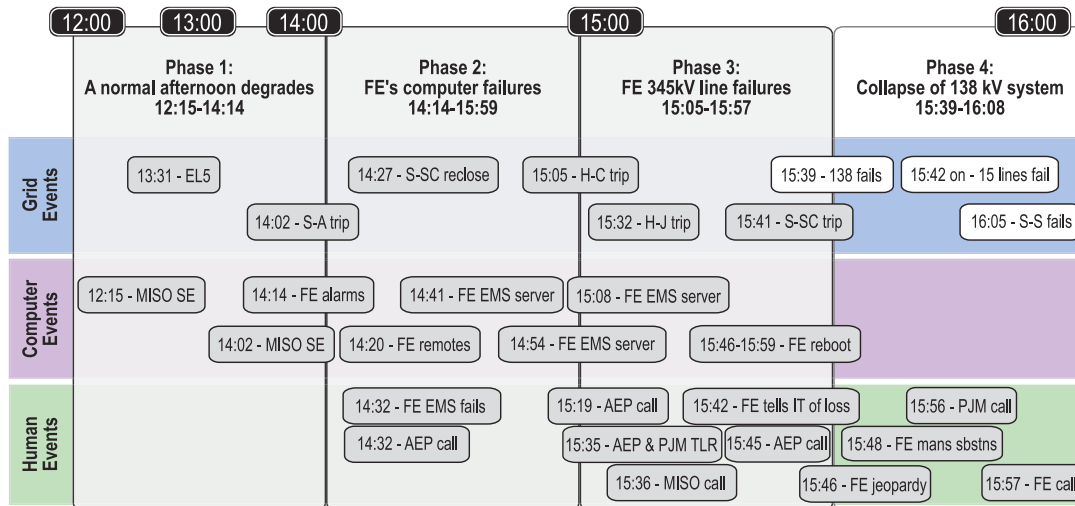
Phase 4: 138-kV Transmission System Collapse in Northern Ohio: 15:39 to 16:08 EDT

Overview of This Phase

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

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

Key Phase 4 Events

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

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

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

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

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

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

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

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

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

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

Figure 5.14. Voltages on FirstEnergy's 138-kV Lines: Impact of Line Trips
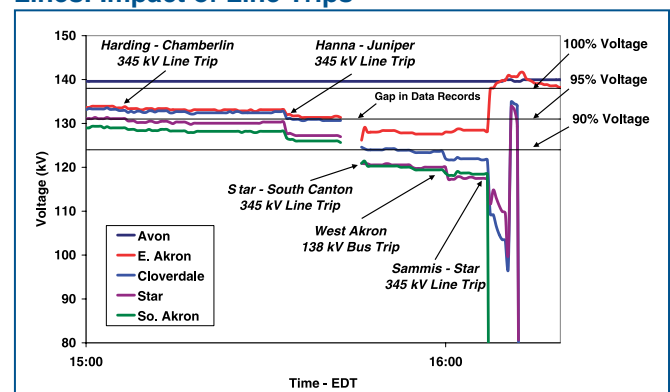
which then opened the line to FE's Cloverdale station.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Losing the 138-kV Transmission Lines

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

Cause 1
Inadequate System Understanding

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

Cause 2
Inadequate Situational Awareness

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

Preventing the Blackout with Load-Shedding

Cause 1
Inadequate System Understanding

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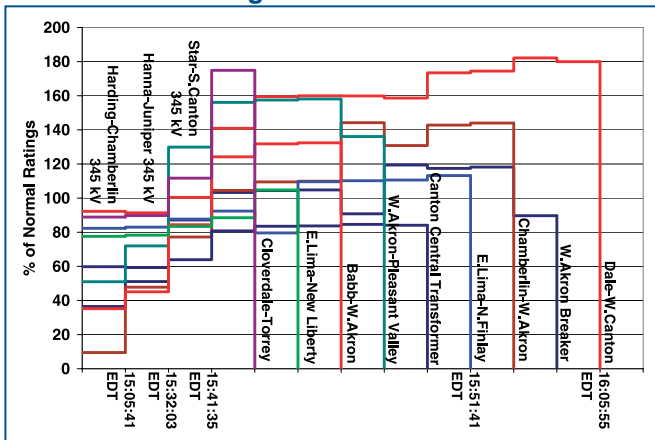
dropped within the Cleveland-Akron area to restore voltage at the Star bus from 90.8% (at 120% of normal and emergency ampere rating) up to 95.9% (at 101% of normal and emergency ampere rating).[44] The P-V and V-Q analysis reviewed in Chapter 4 indicated that 95% is the minimum operating voltage appropriate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

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

Loss of the Sammis-Star 345-kV Line

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

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

Recommendation
21, page 158

Endnotes

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

23 Investigation team transcript, meeting on September 9, 2003, comments by Mr. Steve Morgan, Vice President Electric Operations:
Mr. Morgan: The sustained outage history for these lines, 2001, 2002, 2003, up until the event, Chamberlin-Harding had zero operations for those two-and-a-half years. And Hanna-Juniper had six operations in 2001, ranging from four minutes to maximum of 34 minutes. Two were unknown, one was lightning, one was a relay failure, and two were really relay scheme mis-operations. They're category other. And typically, that—I don't know what this is particular to operations, that typically occurs when there is a mis-operation.
Star-South Canton had no operations in that same period of time, two-and-a-half years. No sustained outages. And Sammis-Star, the line we haven't talked about, also no sustained outages during that two-and-a-half year period. So is it normal? No. But 345 lines do operate, so it's not unknown.

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

25 "FE MISO Findings," page 11.

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

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

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

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

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

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

Mr. Benjamin: Could they have done that?

Mr. Morgan: Yeah, presumably they could have.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

6. The Cascade Stage of the Blackout

Chapter 5 described how uncorrected problems in northern Ohio developed to 16:05:57 EDT, the last point at which a cascade of line trips could have been averted. However, the Task Force's investigation also sought to understand how and why the cascade spread and stopped as it did. As detailed below, the investigation determined the sequence of events in the cascade, and how and why it spread, and how it stopped in each general geographic area.

Based on the investigation to date, the investigation team concludes that the cascade spread beyond Ohio and caused such a widespread blackout for three principal reasons. First, the loss of the Sammis-Star 345-kV line in Ohio, following the loss of other transmission lines and weak voltages within Ohio, triggered many subsequent line trips. Second, many of the key lines which tripped between 16:05:57 and 16:10:38 EDT operated on zone 3 impedance relays (or zone 2 relays set to operate like zone 3s) which responded to overloads rather than true faults on the grid. The speed at which they tripped spread the reach and accelerated the spread of the cascade beyond the Cleveland-Akron area. Third, the evidence collected indicates that the relay protection settings for the transmission lines, generators and under-frequency load-shedding in the northeast may not be entirely appropriate and are certainly not coordinated and integrated to reduce the likelihood and consequences of a cascade—nor were they intended to do so. These issues are discussed in depth below.

This analysis is based on close examination of the events in the cascade, supplemented by complex, detailed mathematical modeling of the electrical phenomena that occurred. At the completion of this report, the modeling had progressed through 16:10:40 EDT, and was continuing. Thus this chapter is informed and validated by modeling (explained below) up until that time. Explanations after that time reflect the investigation team's best hypotheses given the available data, and may be confirmed or modified when the modeling is complete. However, simulation of these events is so complex that it may be impossible to ever completely prove these or other theories about the fast-moving events of August 14. Final modeling results will be published by NERC as a technical report in several months.

Why Does a Blackout Cascade?

Major blackouts are rare, and no two blackout scenarios are the same. The initiating events will vary, including human actions or inactions, system topology, and load/generation balances. Other factors that will vary include the distance between generating stations and major load centers, voltage profiles across the grid, and the types and settings of protective relays in use.

Some wide-area blackouts start with short circuits (faults) on several transmission lines in short succession—sometimes resulting from natural causes such as lightning or wind or, as on August 14, resulting from inadequate tree management in right-of-way areas. A fault causes a high current and low voltage on the line containing the fault. A protective relay for that line detects the high current and low voltage and quickly trips the circuit breakers to isolate that line from the rest of the power system.

A cascade is a dynamic phenomenon that cannot be stopped by human intervention once started. It occurs when there is a sequential tripping of numerous transmission lines and generators in a widening geographic area. A cascade can be triggered by just a few initiating events, as was seen on August 14. Power swings and voltage fluctuations caused by these initial events can cause other lines to detect high currents and low voltages that appear to be faults, even if faults do not actually exist on those other lines. Generators are tripped off during a cascade to protect them from severe power and voltage swings. Protective relay systems work well to protect lines and generators from damage and to isolate them from the system under normal and abnormal system conditions.

But when power system operating and design criteria are violated because several outages occur

simultaneously, commonly used protective relays that measure low voltage and high current cannot distinguish between the currents and voltages seen in a system cascade from those caused by a fault. This leads to more and more lines and generators being tripped, widening the blackout area.

## How Did the Cascade Evolve on August 14?

A series of line outages in northeast Ohio starting at 15:05 EDT caused heavy loadings on parallel circuits, leading to the trip and lock-out of FE's Sammis-Star 345-kV line at 16:05:57 Eastern Daylight Time. This was the event that triggered a cascade of interruptions on the high voltage system, causing electrical fluctuations and facility trips such that within seven minutes the blackout rippled from the Cleveland-Akron area across much of the northeast United States and Canada. By 16:13 EDT, more than 508 generating units at 265 power plants had been lost, and tens of millions of people in the United States and Canada were without electric power.

The events in the cascade started relatively slowly. Figure 6.1 illustrates how the number of lines and generation lost stayed relatively low during the Ohio phase of the blackout, but then picked up speed after 16:08:59 EDT. The cascade was complete only three minutes later.

Chapter 5 described the four phases that led to the initiation of the cascade at about 16:06 EDT. After 16:06 EDT, the cascade evolved in three distinct phases:

◆ **Phase 5.** The collapse of FE's transmission system induced unplanned shifts of power across the region. Shortly before the collapse, large (but normal) electricity flows were moving across FE's system from generators in the south (Tennessee and Kentucky) and west (Illinois and Missouri) to load centers in northern Ohio, eastern Michigan, and Ontario. A series of lines within northern Ohio tripped under the high

Figure 6.1. Rate of Line and Generator Trips During the Cascade
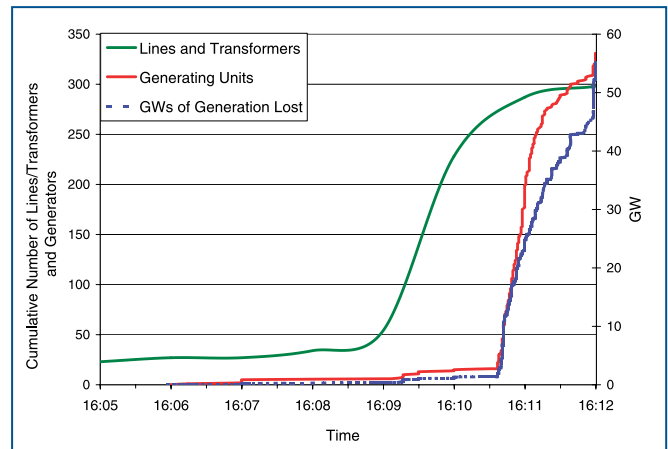
Impedance Relays

The most common protective device for transmission lines is the impedance (Z) relay (also known as a distance relay). It detects changes in currents (I) and voltages (V) to determine the apparent impedance ($Z=V/I$) of the line. A relay is installed at each end of a transmission line. Each relay is actually three relays within one, with each element looking at a particular "zone" or length of the line being protected.

◆ The first zone looks for faults over 80% of the line next to the relay, with no time delay before the trip.

◆ The second zone is set to look at the entire line and slightly beyond the end of the line with a slight time delay. The slight delay on the zone 2 relay is useful when a fault occurs near one end of the line. The zone 1 relay near that end operates quickly to trip the circuit breakers on that end. However, the zone 1 relay on the other end may not be able to tell if the fault is

just inside the line or just beyond the line. In this case, the zone 2 relay on the far end trips the breakers after a short delay, after the zone 1 relay near the fault opens the line on that end first.

◆ The third zone is slower acting and looks for line faults and faults well beyond the length of the line. It can be thought of as a remote relay or breaker backup, but should not trip the breakers under typical emergency conditions.

An impedance relay operates when the apparent impedance, as measured by the current and voltage seen by the relay, falls within any one of the operating zones for the appropriate amount of time for that zone. The relay will trip and cause circuit breakers to operate and isolate the line. All three relay zone operations protect lines from faults and may trip from apparent faults caused by large swings in voltages and currents.

loads, hastened by the impact of Zone 3 impedance relays. This caused a series of shifts in power flows and loadings, but the grid stabilized after each.

◆ **Phase 6.** After 16:10:36 EDT, the power surges resulting from the FE system failures caused lines in neighboring areas to see overloads that caused impedance relays to operate. The result was a wave of line trips through western Ohio that separated AEP from FE. Then the line trips progressed northward into Michigan separating western and eastern Michigan, causing a power flow reversal within Michigan toward Cleveland. Many of these line trips were from Zone 3 impedance relay actions that accelerated the speed of the line trips and reduced the potential time in which grid operators might have identified the growing problem and acted constructively to contain it.

With paths cut from the west, a massive power surge flowed from PJM into New York and Ontario in a counter-clockwise flow around Lake Erie to serve the load still connected in eastern Michigan and northern Ohio. Relays on the lines between PJM and New York saw this massive power surge as faults and tripped those lines. Ontario's east-west tie line also became overloaded and tripped, leaving northwest Ontario connected to Manitoba and Minnesota. The entire northeastern United States and eastern Ontario then became a large electrical island separated from the rest of the Eastern Interconnection. This large area, which had been importing power prior to the cascade, quickly became unstable after 16:10:38 as there was not sufficient generation on-line within the island to meet electricity demand. Systems to the south and west of the split, such as PJM, AEP and others further away, remained intact and were mostly unaffected by the outage. Once the northeast split from the rest of the Eastern Interconnection, the cascade was isolated.

◆ **Phase 7.** In the final phase, after 16:10:46 EDT, the large electrical island in the northeast had less generation than load, and was unstable with large power surges and swings in frequency and voltage. As a result, many lines and generators across the disturbance area tripped, breaking the area into several electrical islands. Generation and load within these smaller islands was often unbalanced, leading to further tripping of lines and generating units until equilibrium was established in each island.

Although much of the disturbance area was fully blacked out in this process, some islands were able to reach equilibrium without total loss of service. For example, the island consisting of most of New England and the Maritime Provinces stabilized and generation and load returned to balance. Another island consisted of load in western New York and a small portion of Ontario, supported by some New York generation, the large Beck and Saunders plants in Ontario, and the 765-kV interconnection to Québec. This island survived but some other areas with large load centers within the island collapsed into a blackout condition (Figure 6.2).

What Stopped the August 14 Blackout from Cascading Further?

The investigation concluded that a combination of the following factors determined where and when the cascade stopped spreading:

◆ The effects of a disturbance travel over power lines and become damped the further they are from the initial point, much like the ripple from a stone thrown in a pond. Thus, the voltage and current swings seen by relays on lines farther away from the initial disturbance are not as severe, and at some point they are no longer sufficient to cause lines to trip.

◆ Higher voltage lines and more densely networked lines, such as the 500-kV system in PJM and the 765-kV system in AEP, are better able to absorb voltage and current swings and thus serve as a barrier to the spread of a cascade. As seen in Phase 6, the cascade progressed into western Ohio and then northward through Michigan through the areas that had the fewest transmission lines. Because there were fewer

Figure 6.2. Area Affected by the Blackout
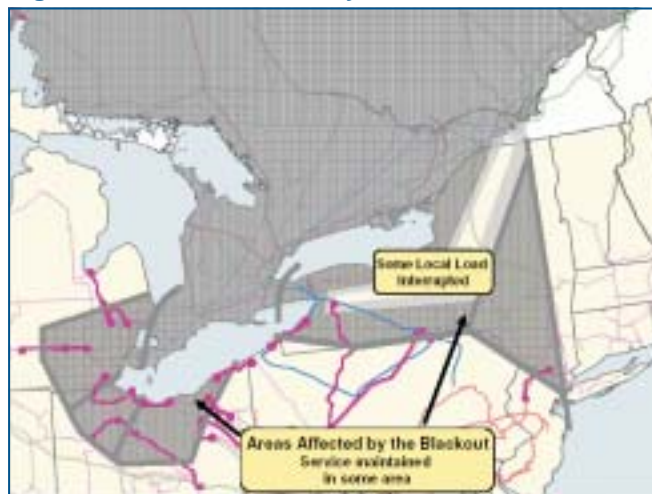
System Oscillations, Stable, Transient, and Dynamic Conditions

The electric power system constantly experiences small power oscillations that do not lead to system instability. They occur as generator rotors accelerate or slow down while rebalancing electrical output power to mechanical input power, to respond to changes in load or network conditions. These oscillations are observable in the power flow on transmission lines that link generation to load or in the tie lines that link different regions of the system together. But with a disturbance to the network, the oscillations can become more severe, even to the point where flows become progressively so great that protective relays trip the connecting lines. If the lines connecting different electrical regions separate, each region will find its own frequency, depending on the load to generation balance at the time of separation.

Oscillations that grow in amplitude are called unstable oscillations. Such oscillations, once initiated, cause power to flow back and forth across the system like water sloshing in a rocking tub.

In a stable electric system, if a disturbance such as a fault occurs, the system will readjust and rebalance within a few seconds after the fault clears. If a fault occurs, protective relays can trip in less than 0.1 second. If the system recovers and rebalances within less than 3 seconds, with the possible loss of only the faulted element and a few generators in the area around the fault, then that condition is termed "transiently stable." If the system takes from 3 to 30 seconds to recover and stabilize, it is "dynamically stable." But in

rare cases when a disturbance occurs, the system may appear to rebalance quickly, but it then over-shoots and the oscillations can grow, causing widespread instability that spreads in terms of both the magnitude of the oscillations and in geographic scope. This can occur in a system that is heavily loaded, causing the electrical distance (apparent impedance) between generators to be longer, making it more difficult to keep the machine angles and speeds synchronized. In a system that is well damped, the oscillations will settle out quickly and return to a steady balance. If the oscillation continues over time, neither growing nor subsiding, it is a poorly damped system.

The illustration below, of a weight hung on a spring balance, illustrates a system which oscillates over several cycles to return to balance. A critical point to observe is that in the process of hunting for its balance point, the spring over-shoots the true weight and balance point of the spring and weight combined, and must cycle through a series of exaggerated overshoots and underweight rebounds before settling down to rest at its true balance point. The same process occurs on an electric system, as can be observed in this chapter.

If a system is in transient instability, the oscillations following a disturbance will grow in magnitude rather than settle out, and it will be unable to readjust to a stable, steady state. This is what happened to the area that blacked out on August 14, 2003.

weight is added

Time
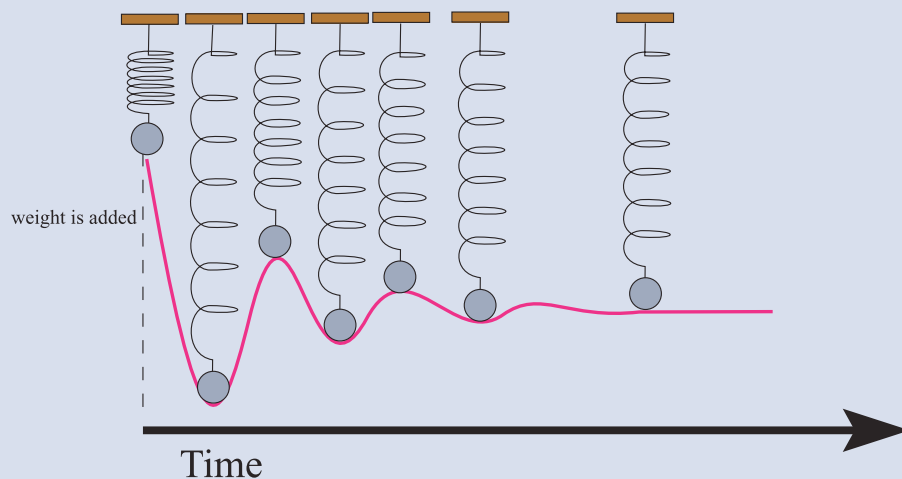
lines, each line absorbed more of the power and voltage surges and was more vulnerable to tripping. A similar effect was seen toward the east as the lines between New York and Pennsylvania, and eventually northern New Jersey tripped. The cascade of transmission line outages became contained after the northeast United States and Ontario were completely separated from the rest of the Eastern Interconnection and no more power flows were possible into the northeast (except the DC ties from Québec, which continued to supply power to western New York and New England).

◆ Line trips isolated some areas from the portion of the grid that was experiencing instability. Many of these areas retained sufficient on-line generation or the capacity to import power from other parts of the grid, unaffected by the surges or instability, to meet demand. As the cascade progressed, and more generators and lines tripped off to protect themselves from severe damage, some areas completely separated from the unstable part of the Eastern Interconnection. In many of these areas there was sufficient generation to match load and stabilize the system. After the large island was formed in the northeast, symptoms of frequency and voltage decay emerged. In some parts of the northeast, the system became too unstable and shut itself down. In other parts, there was sufficient generation, coupled with fast-acting automatic load shedding, to stabilize frequency and voltage. In this manner, most of New England and the Maritime Provinces remained energized. Approximately half of the generation and load remained on in western New York, aided by generation in southern Ontario that split and stayed with western New York. There were other smaller isolated pockets of load and generation that were able to achieve equilibrium and remain energized.

Phase 5:
345-kV Transmission System Cascade in Northern Ohio and South-Central Michigan

Overview of This Phase

After the loss of FE's Sammis-Star 345-kV line and the underlying 138-kV system, there were no large capacity transmission lines left from the south to support the significant amount of load in northern Ohio (Figure 6.3). This overloaded the

transmission paths west and northwest into Michigan, causing a sequential loss of lines and power plants.

Key Events in This Phase

5A) 16:05:57 EDT: Sammis-Star 345-kV tripped by zone 3 relay.

5B) 16:08:59 EDT: Galion-Ohio Central-Muskingum 345-kV line tripped on zone 3 relay.

5C) 16:09:06 EDT: East Lima-Fostoria Central 345-kV line tripped on zone 3 relay, causing major power swings through New York and Ontario into Michigan.

5D) 16:09:08 EDT to 16:10:27 EDT: Several power plants lost, totaling 937 MW.

5A) Sammis-Star 345-kV Tripped: 16:05:57 EDT

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 zone 3 relay action that measured low apparent impedance (depressed voltage divided by abnormally high line current) (Figure 6.4). 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 an exceptionally 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 because of the current overload. The relay operated as it was designed to do.

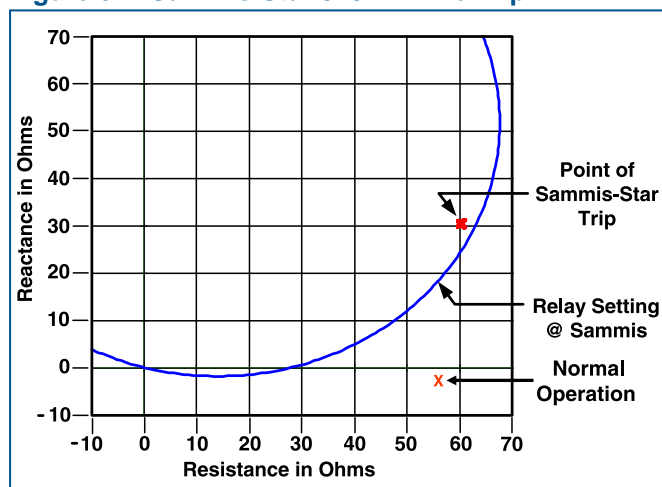**Figure 6.3. Sammis-Star 345-kV Line Trip, 16:05:57 EDT**
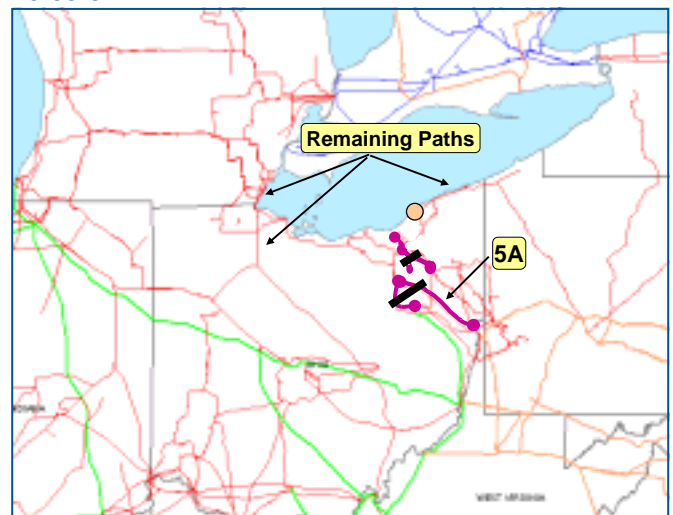
The Sammis-Star 345-kV line trip completely severed the 345-kV path into northern Ohio from southeast Ohio, triggering a new, fast-paced sequence of 345-kV transmission line trips in which each line trip placed a greater flow burden on those lines remaining in service. These line outages left only three paths for power to flow into western Ohio: (1) from northwest Pennsylvania to northern Ohio around the south shore of Lake Erie, (2) from southwest Ohio toward northeast Ohio, and (3) from eastern Michigan and Ontario. The line interruptions substantially weakened northeast Ohio 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. The impact of this trip was felt across the grid—it caused a 100 MW increase in flow from PJM into New York and through to Ontario.[1] Frequency in the Eastern Interconnection increased momentarily by 0.02 Hz.

Soon after the Sammis-Star trip, four of the five 48 MW Handsome Lake combustion turbines in western Pennsylvania tripped off-line. These units are connected to the 345-kV system by the Homer City-Wayne 345-kV line, and were operating that day as synchronous condensers to participate in PJM's spinning reserve market (not to provide voltage support). When Sammis-Star tripped and increased loadings on the local transmission system, the Handsome Lake units were close enough electrically to sense the impact and tripped off-line at 16:07:00 EDT on under-voltage.

During the period between the Sammis-Star trip and the trip of East Lima-Fostoria at 16:09:06.3 EDT, the system was still in a steady-state condition. Although one line after another was overloading and tripping within Ohio, this was happening slowly enough under relatively stable conditions that the system could readjust—after each line loss, power flows would redistribute across the remaining lines. This is illustrated in Figure 6.5, which shows the MW flows on the Michigan Electrical Coordinated Systems (MECS) interfaces with AEP (Ohio), FirstEnergy (Ohio) and Ontario. The graph shows a shift from 150 MW imports to 200 MW exports from the MECS system into FirstEnergy at 16:05:57 EDT after the loss of Sammis-Star, after which this held steady until 16:08:59, when the loss of East Lima-Fostoria Central cut the main energy path from the south and west into Cleveland and Toledo. Loss of this path was significant, causing flow from MECS into FE to jump from 200 MW up to 2,300 MW, where it bounced somewhat before stabilizing, roughly, until the path across Michigan was cut at 16:10:38 EDT.

Transmission Lines into Northwestern Ohio Tripped, and Generation Tripped in South Central Michigan and Northern Ohio: 16:08:59 EDT to 16:10:27 EDT

5B) 16:08:59 EDT: Galion-Ohio Central-Muskingum 345-kV line tripped

5C) 16:09:06 EDT: East Lima-Fostoria Central 345-kV line tripped, causing a large power swing from Pennsylvania and New York through Ontario to Michigan

The tripping of the Galion-Ohio Central-Muskingum and East Lima-Fostoria Central

Figure 6.4. Sammis-Star 345-kV Line Trip

Figure 6.5. Line Flows Into Michigan
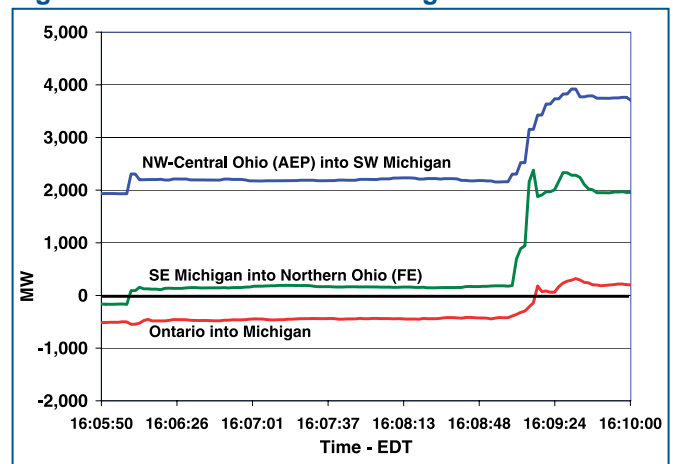
Note: These curves use data collected from the MECS Energy Management System, which records flow quantities every 2 seconds. As a result, the fast power swings that occurred between 16:10:36 to 16:13 were not captured by the recorders and are not reflected in these curves.

345-kV transmission lines removed the transmission paths from southern and western Ohio into northern Ohio and eastern Michigan. Northern Ohio was connected to eastern Michigan by only three 345-kV transmission lines near the southwestern bend of Lake Erie. Thus, the combined northern Ohio and eastern Michigan load centers were left connected to the rest of the grid only by: (1) transmission lines eastward from northeast Ohio to northwest Pennsylvania along the southern shore of Lake Erie, and (2) westward by lines west and northwest of Detroit, Michigan and from Michigan into Ontario (Figure 6.6).

The Galion-Ohio Central-Muskingum 345-kV line tripped first at Muskingum at 16:08:58.5 EDT on a phase-to-ground fault, reclosed and tripped again at 16:08:58.6 at Ohio Central, reclosed and tripped again at Muskingum on a Zone 3 relay, and finally tripped at Galion on a ground fault.

After the Galion-Ohio Central-Muskingum line outage and numerous 138-kV line trips in central Ohio, the East Lima-Fostoria Central 345-kV line tripped at 16:09:06 EDT on Zone 3 relay operation due to high current and extremely low voltage (80%). Investigation team modeling indicates that if automatic under-voltage load-shedding had been in place in northeast Ohio, it might have been triggered at or before this point, and dropped enough load to reduce or eliminate the subsequent line overloads that spread the cascade.

> **Recommendation s**
> **8, page 147; 21, page 158**

Figure 6.7, a high-speed recording of 345-kV flows past Niagara Falls from the Hydro One recorders,
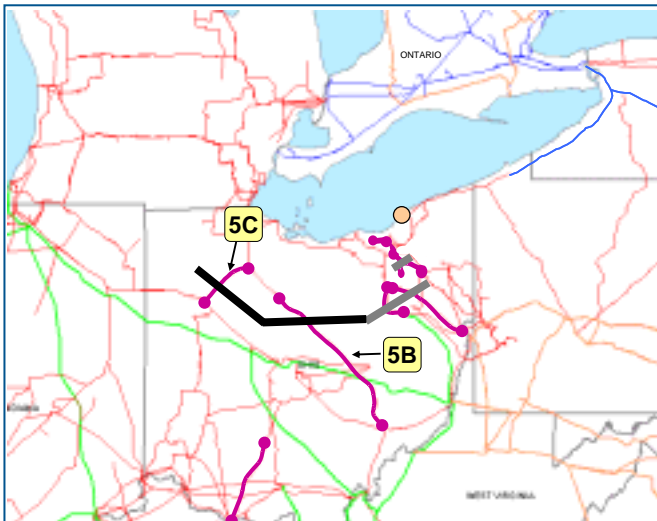
shows the impact of the East Lima-Fostoria Central and the New York to Ontario power swing, which continued to oscillate for over 10 seconds. Looking at the MW flow line, it is clear that when Sammis-Star tripped, the system experienced oscillations that quickly damped out and rebalanced. But East Lima-Fostoria triggered significantly greater oscillations that worsened in magnitude for several cycles, and returned to stability but continued to flutter until the Argenta-Battle Creek trip 90 seconds later. Voltages also began declining at this time.

After the East Lima-Fostoria Central trip, power flows increased dramatically and quickly on the lines into and across southern Michigan. Although power had initially been flowing northeast out of Michigan into Ontario, that flow suddenly reversed and approximately 500 to 700 MW of power (measured at the Michigan-Ontario border, and 437 MW at the Ontario-New York border at Niagara) flowed southwest out of Ontario through Michigan to serve the load of Cleveland and Toledo. This flow was fed by 700 MW pulled out of PJM through New York on its 345-kV network.[2] This was the first of several inter-area power and frequency events that occurred over the next two minutes. This was the system's response to the loss of the northwest Ohio transmission paths (above), and the stress that the still-high Cleveland, Toledo, and Detroit loads put onto the surviving lines and local generators.

Figure 6.7 also shows the magnitude of subsequent flows and voltages at the New York-Ontario Niagara border, triggered by the trips of the Argenta-Battle Creek, Argenta-Tompkins, Hampton-Pontiac and Thetford-Jewell 345-kV lines in Michigan, and the Erie West-Ashtabula-Perry

Figure 6.6. Ohio 345-kV Lines Trip, 16:08:59 to 16:09:07 EDT

Figure 6.7. New York-Ontario Line Flows at Niagara
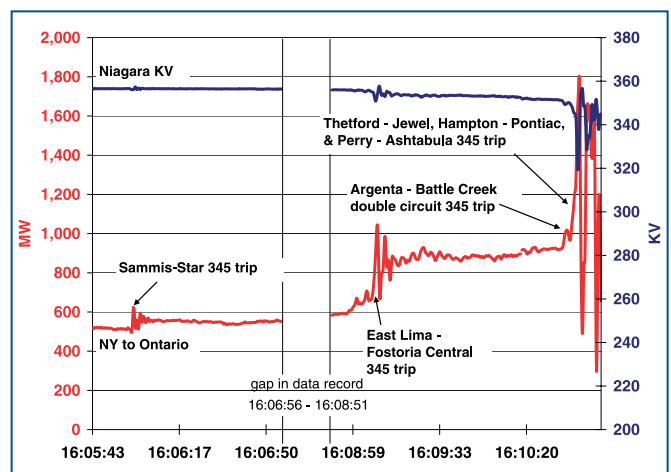
345-kV line linking the Cleveland area to Pennsylvania. Farther south, the very low voltages on the northern Ohio transmission system made it very difficult for the generation in the Cleveland and Lake Erie area to maintain synchronism with the Eastern Interconnection. Over the next two minutes, generators in this area shut down after reaching a point of no recovery as the stress level across the remaining ties became excessive.

Figure 6.8, of metered power flows along the New York interfaces, documents how the flows heading north and west toward Detroit and Cleveland varied at different points on the grid. Beginning at 16:09:05 EDT, power flows jumped simultaneously across all three interfaces—but when the first power surge peaked at 16:09:09, the change in flow was highest on the PJM interface and lowest on the New England interface. Power flows increased significantly on the PJM-NY and NY-Ontario interfaces because of the redistribution of flow around Lake Erie. The New England and Maritime systems maintained the same generation to load balance and did not carry the redistributed flows because they were not in the direct path of the flows, so that interface with New York showed little response.

Before this first major power swing on the Michigan/Ontario interface, power flows in the NPCC Region (Québec, Ontario and the Maritimes, New England and New York) were typical for the summer period, and well within acceptable limits. Transmission and generation facilities were then in a secure state across the NPCC region.

Zone 3 Relays and the Start of the Cascade

Zone 3 relays are set to provide breaker failure and relay backup for remote distance faults on a transmission line. If it senses a fault past the immediate

reach of the line and its zone 1 and zone 2 settings, a zone 3 relay waits through a 1 to 2 second time delay to allow the primary line protection to act first. A few lines have zone 3 settings designed with overload margins close to the long-term emergency limit of the line, because the length and configuration of the line dictate a higher apparent impedance setting. Thus it is possible for a zone 3 relay to operate on line load or overload in extreme contingency conditions even in the absence of a fault (which is why many regions in the United States and Canada have eliminated the use of zone 3 relays on 230-kV and greater lines). Some transmission operators set zone 2 relays to serve the same purpose as zone 3s—i.e., to reach well beyond the length of the line it is protecting and protect against a distant fault on the outer lines.

The Sammis-Star line tripped at 16:05:57 EDT on a zone 3 impedance relay although there were no faults occurring at the time, because increased real and reactive power flow caused the apparent impedance to be within the impedance circle (reach) of the relay. Between 16:06:01 and 16:10:38.6 EDT, thirteen more important 345 and 138-kV lines tripped on zone 3 operations that afternoon at the start of the cascade, including Galion-Ohio Central-Muskingum, East Lima-Fostoria Central, Argenta-Battle Creek, Argenta-Tompkins, Battle Creek-Oneida, and Perry-Ashtabula (Figure 6.9). These included several zone 2 relays in Michigan that had been set to operate like zone 3s, overreaching the line by more than 200% with no intentional time delay for remote breaker failure protection.[3] All of these relays operated according to their settings. However, the zone 3 relays (and zone 2 relays acting like zone 3s) acted so quickly that they impeded the natural ability of the electric system to hold together, and did not allow for any operator intervention to attempt to stop the spread of the cascade. The investigation team concluded that because these zone 2 and 3 relays tripped after each line overloaded, these relays were the common mode of failure that accelerated the geographic spread of the cascade. Given grid conditions and loads and the limited operator tools available, the speed of the zone 2 and 3 operations across Ohio and Michigan eliminated any possibility after 16:05:57 EDT that either operator action or automatic intervention could have limited or mitigated the growing cascade.

What might have happened on August 14 if these lines had not tripped on zone 2 and 3 relays? Each

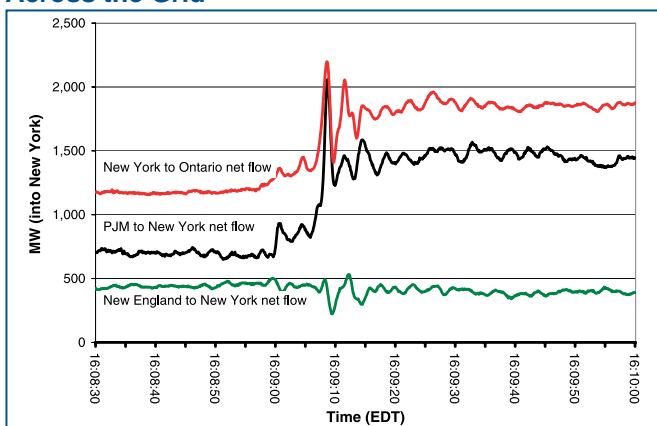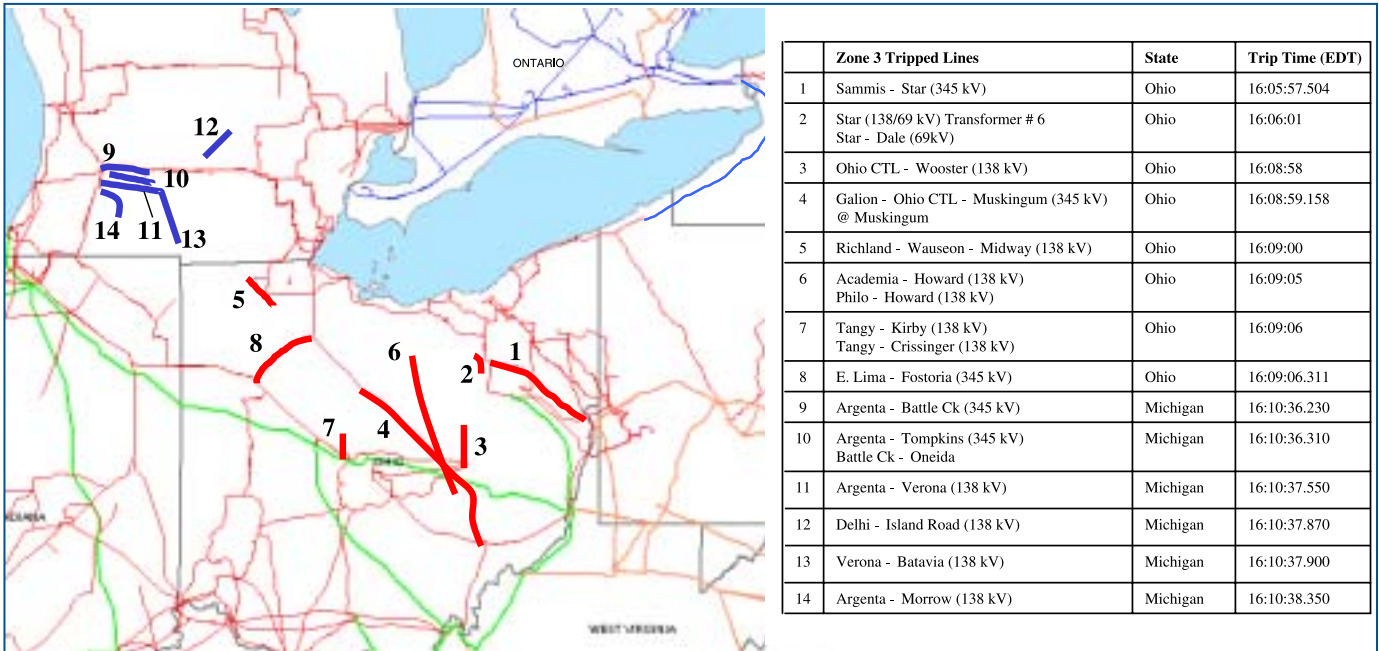**Figure 6.8. First Power Swing Has Varying Impacts Across the Grid**

	Zone 3 Tripped Lines	State	Trip Time (EDT)
1	Sammis - Star (345 kV)	Ohio	16:05:57.504
2	Star (138/69 kV) Transformer # 6 Star - Dale (69kV)	Ohio	16:06:01
3	Ohio CTL - Wooster (138 kV)	Ohio	16:08:58
4	Galion - Ohio CTL - Muskingum (345 kV) @ Muskingum	Ohio	16:08:59.158
5	Richland - Wauseon - Midway (138 kV)	Ohio	16:09:00
6	Academia - Howard (138 kV) Philo - Howard (138 kV)	Ohio	16:09:05
7	Tangy - Kirby (138 kV) Tangy - Crissinger (138 kV)	Ohio	16:09:06
8	E. Lima - Fostoria (345 kV)	Ohio	16:09:06.311
9	Argenta - Battle Ck (345 kV)	Michigan	16:10:36.230
10	Argenta - Tompkins (345 kV) Battle Ck - Oneida	Michigan	16:10:36.310
11	Argenta - Verona (138 kV)	Michigan	16:10:37.550
12	Delhi - Island Road (138 kV)	Michigan	16:10:37.870
13	Verona - Batavia (138 kV)	Michigan	16:10:37.900
14	Argenta - Morrow (138 kV)	Michigan	16:10:38.350

Voltage Collapse

Although the blackout of August 14 has been labeled by some as a voltage collapse, it was not a voltage collapse as that term has been traditionally used by power system engineers. Voltage collapse occurs when an increase in load or loss of generation or transmission facilities causes dropping voltage, which causes a further reduction in reactive power from capacitors and line charging, and still further voltage reductions. If the declines continue, these voltage reductions cause additional elements to trip, leading to further reduction in voltage and loss of load. The result is a progressive and uncontrollable decline in voltage, all because the power system is unable to provide the reactive power required to supply the reactive power demand. This did not occur on August 14. While the Cleveland-Akron area was short of reactive power reserves they were just sufficient to supply the reactive power demand in the area and maintain stable albeit depressed voltages for the outage conditions experienced.

But the lines in the Cleveland-Akron area tripped as a result of tree contacts well below the nominal rating of the lines and **not due to low voltages**, which is a precursor for voltage collapse. The initial trips within FirstEnergy began because of ground faults with untrimmed trees, not because of a shortage of reactive power and low voltages. Voltage levels were within workable bounds before individual transmission trips began, and those trips occurred within normal line ratings rather than in overloads. With fewer lines operational, current flowing over the remaining lines increased and voltage decreased (current increases in inverse proportion to the decrease in voltage for a given amount of power flow)—but it stabilized after each line trip until the next circuit trip. Soon northern Ohio lines began to trip out automatically on protection from overloads, not from insufficient reactive power. Once several lines tripped in the Cleveland-Akron area, the power flow was rerouted to other heavily loaded lines in northern Ohio, causing depressed voltages which led to automatic tripping on protection from overloads. Voltage collapse therefore was not a cause of the cascade.

As the cascade progressed beyond Ohio, it spread due not to insufficient reactive power and a voltage collapse, but because of dynamic power swings and the resulting system instability. Figure 6.7 shows voltage levels recorded at the Niagara area. It shows clearly that voltage levels remained stable until 16:10:30 EDT, despite significant power fluctuations. In the cascade that followed, the voltage instability was a companion to, not a driver of, the angle instability that tripped generators and lines.

was operating with high load, and loads on each line grew as each preceding line tripped out of service. But if these lines had not tripped quickly on zone 2s and 3s, each might have remained heavily loaded, with conductor temperatures increasing, for as long as 20 to 30 minutes before the line sagged into something and experienced a ground fault. For instance, the Dale-West Canton line took 20 minutes to trip under 160 to 180% of its normal rated load. Even with sophisticated modeling it is impossible to predict just how long this delay might have occurred (affected by wind speeds, line loadings, and line length, tension and ground clearance along every span), because the system did not become dynamically unstable until at least after the Thetford-Jewell trip at 16:10:38 EDT. During this period the system would likely have remained stable and been able to readjust after each line trip on ground fault. If this period of deterioration and overloading under stable conditions had lasted for as little as 15 minutes or as long as an hour, it is possible that the growing problems could have been recognized and action taken, such as automatic under-voltage load-shedding, manual load-shedding in Ohio or other measures. So although the operation of zone 2 and 3 relays in Ohio and Michigan did not cause the blackout, it is certain that they greatly expanded and accelerated the spread of the cascade.

> **Recommendation 21, page 158**

5D) Multiple Power Plants Tripped, Totaling 946 MW: 16:09:08 to 16:10:27 EDT

16:09:08 EDT: Michigan Cogeneration Venture plant reduction of 300 MW (from 1,263 MW to 963 MW)

16:09:17 EDT: Avon Lake 7 unit trips (82 MW)

16:09:17 EDT: Burger 3, 4, and 5 units trip (355 MW total)

16:09:30 EDT: Kinder Morgan units 3, 6 and 7 trip (209 MW total)

The Burger units tripped after the 138-kV lines into the Burger 138-kV substation (Ohio) tripped from the low voltages in the Cleveland area (Figure 6.10). The MCV plant is in central Michigan. Kinder Morgan is in south-central Michigan. The Kinder-Morgan units tripped due to a transformer fault and one due to over-excitation.

Power flows into Michigan from Indiana increased to serve loads in eastern Michigan and northern Ohio (still connected to the grid through northwest Ohio and Michigan) and voltages dropped from the imbalance between high loads

and limited transmission and generation capability.

Phase 6: The Full Cascade

Between 16:10:36 EDT and 16:13 EDT, thousands of events occurred on the grid, driven by physics and automatic equipment operations. When it was over, much of the northeastern United States and the province of Ontario were in the dark.

Key Phase 6 Events

Transmission Lines Disconnected Across Michigan and Northern Ohio, Generation Shut Down in Central Michigan and Northern Ohio, and Northern Ohio Separated from Pennsylvania: 16:10:36 to 16:10:39 EDT

6A) Transmission and more generation tripped within Michigan: 16:10:36 to 16:10:37 EDT:

16:10:36.2 EDT: Argenta-Battle Creek 345-kV line tripped

16:10:36.3 EDT: Argenta-Tompkins 345-kV line tripped

16:10:36.8 EDT: Battle Creek-Oneida 345-kV line tripped

16:10:37 EDT: Sumpter Units 1, 2, 3, and 4 units tripped on under-voltage (300 MW near Detroit)

16:10:37.5 EDT: MCV Plant output dropped from 963 MW to 109 MW on over-current protection.

Together, the above line outages interrupted the west-to-east transmission paths into the Detroit area from south-central Michigan. The Sumpter generation units tripped in response to

Figure 6.10. Michigan and Ohio Power Plants Trip
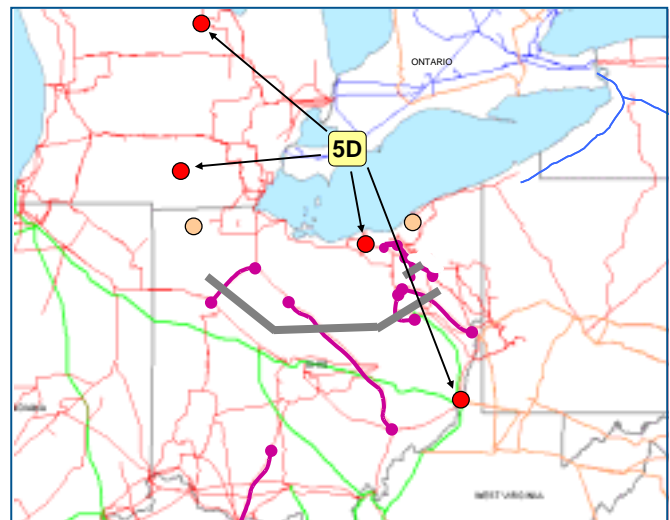
under-voltage on the system. Michigan lines west of Detroit then began to trip, as shown in Figure 6.11.

The Argenta-Battle Creek relay first opened the line at 16:10:36.230 EDT, reclosed it at 16:10:37, then tripped again. This line connects major generators—including the Cook and Palisades nuclear plants and the Campbell fossil plant—to the MECS system. This line is designed with auto-reclose breakers at each end of the line, which do an automatic high-speed reclose as soon as they open to restore the line to service with no interruptions. Since the majority of faults on the North American grid are temporary, automatic reclosing can enhance stability and system reliability. However, situations can occur when the power systems behind the two ends of the line could go out of phase during the high-speed reclose period (typically less than 30 cycles, or one half second, to allow the air to de-ionize after the trip to prevent arc re-ignition). To address this and protect generators from the harm that an out-of-synchronism reconnect could cause, it is worth studying whether a synchro-check relay is needed, to reclose the second breaker only when the two ends are within a certain voltage and phase angle tolerance. No such protection was installed at Argenta-Battle Creek; when the line reclosed, there was a 70° difference in phase across the circuit breaker reclosing the line. There

Figure 6.11. Transmission and Generation Trips in Michigan, 16:10:36 to 16:10:37 EDT

is no evidence that the reclose caused harm to the local generators.

6B) Western and Eastern Michigan separation started: 16:10:37 EDT to 16:10:38 EDT

16:10:38.2 EDT: Hampton-Pontiac 345-kV line tripped

16:10:38.4 EDT: Thetford-Jewell 345-kV line tripped

After the Argenta lines tripped, the phase angle between eastern and western Michigan began to increase. The Hampton-Pontiac and Thetford-Jewell 345-kV lines were the only lines remaining connecting Detroit to power sources and the rest of the grid to the north and west. When these lines tripped out of service, it left the loads in Detroit, Toledo, Cleveland, and their surrounding areas served only by local generation and the lines north of Lake Erie connecting Detroit east to Ontario and the lines south of Lake Erie from Cleveland east to northwest Pennsylvania. These trips completed the extra-high voltage network separation between eastern and western Michigan.

The Power System Disturbance Recorders at Keith and Lambton, Ontario, captured these events in the flows across the Ontario-Michigan interface, as shown in Figure 6.12 and Figure 6.16. It shows clearly that the west to east Michigan separation (the Thetford-Jewell trip) was the start and Erie West-Ashtabula-Perry was the trigger for the 3,700 MW surge from Ontario into Michigan. When Thetford-Jewell tripped, power that had been flowing into Michigan and Ohio from western Michigan, western Ohio and Indiana was cut off. The nearby Ontario recorders saw a pronounced impact as flows into Detroit readjusted to draw power from the northeast instead. To the south,
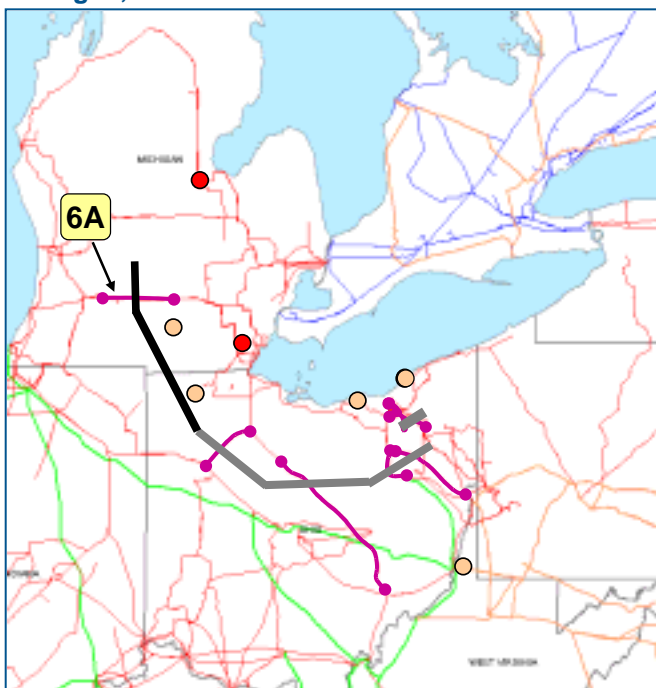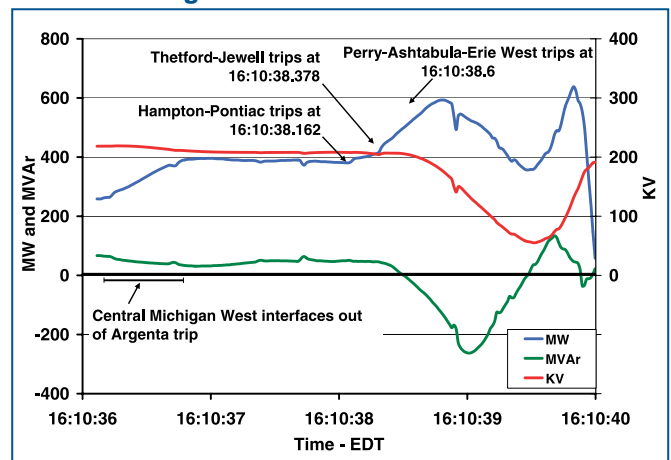
**Figure 6.12. Flows on Keith-Waterman 230-kV Ontario-Michigan Tie Line**

Erie West-Ashtabula-Perry was the last 345-kV eastern link for northern Ohio loads. When that line severed, all the power that moments before had flowed across Michigan and Ohio paths was now diverted in a counter-clockwise direction around Lake Erie through the single path left in eastern Michigan, pulling power out of Ontario, New York and PJM.

Figures 6.13 and 6.14 show the results of investigation team modeling of the line loadings on the Ohio, Michigan, and other regional interfaces for the period between 16:05:57 until the Thetford-Jewell trip, to understand how power flows shifted during this period. The team simulated evolving system conditions on August 14, 2003, based on the 16:05:50 power flow case developed by the MAAC-ECAR-NPCC Operations Studies Working Group. Each horizontal line in the graph indicates a single or set of 345-kV lines and its loading as a function of normal ratings over time as first one, then another, set of circuits tripped out of service. In general, each subsequent line trip causes the remaining line loadings to rise; where a line drops (as Erie West-Ashtabula-Perry in Figure 6.13 after the Hanna-Juniper trip), that indicates that line loading lightened, most likely due to customers dropped from service. Note that Muskingum and East Lima-Fostoria Central were overloaded before they tripped, but the Michigan west and north interfaces were not overloaded before they tripped. Erie West-Ashtabula-Perry was loaded to 130% after the Hampton-Pontiac and Thetford-Jewell trips.

The Regional Interface Loadings graph (Figure 6.14) shows that loadings at the interfaces between PJM-NY, NY-Ontario and NY-New England were well within normal ratings before the east-west Michigan separation.
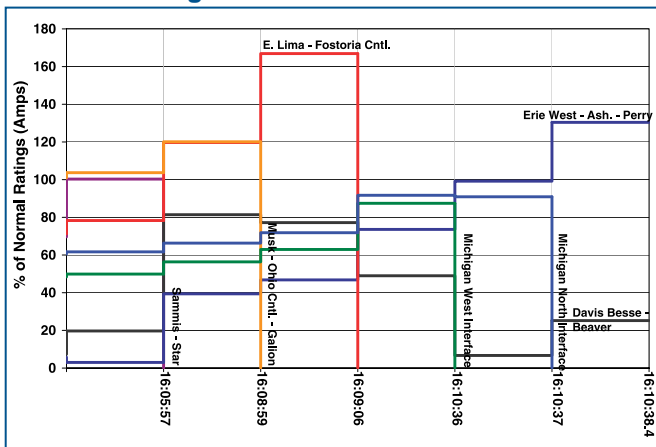
6C) Cleveland separated from Pennsylvania, flows reversed and a huge power surge flowed counter-clockwise around Lake Erie: 16:10:38.6 EDT

16:10:38.6 EDT: Erie West-Ashtabula-Perry 345-kV line tripped at Perry

16:10:38.6 EDT: Large power surge to serve loads in eastern Michigan and northern Ohio swept across Pennsylvania, New Jersey, and New York through Ontario into Michigan.

Perry-Ashtabula was the last 345-kV line connecting northern Ohio to the east south of Lake Erie. This line's trip at the Perry substation on a zone 3 relay operation separated the northern Ohio 345-kV transmission system from Pennsylvania and all eastern 345-kV connections. After this trip, the load centers in eastern Michigan and northern Ohio (Detroit, Cleveland, and Akron) remained connected to the rest of the Eastern Interconnection only to the north at the interface between the Michigan and Ontario systems (Figure 6.15). Eastern Michigan and northern Ohio now had little internal generation left and voltage was declining. The frequency in the Cleveland area dropped rapidly, and between 16:10:39 and 16:10:50 EDT under-frequency load shedding in the Cleveland area interrupted about 1,750 MW of load. However, the load shedding did not drop enough load relative to local generation to rebalance and arrest the frequency decline. Since the electrical system always seeks to balance load and generation, the high loads in Detroit and Cleveland drew power over the only major transmission path remaining—the lines from eastern Michigan into Ontario. Mismatches between generation and load are reflected in changes in frequency, so with more generation than load frequency rises and with less generation than load, frequency falls.

Figure 6.13. Simulated 345-kV Line Loadings from 16:05:57 through 16:10:38.4 EDT

**Figure 6.14. Simulated Regional Interface Loadings from 16:05:57 through 16:10:38.4 EDT**
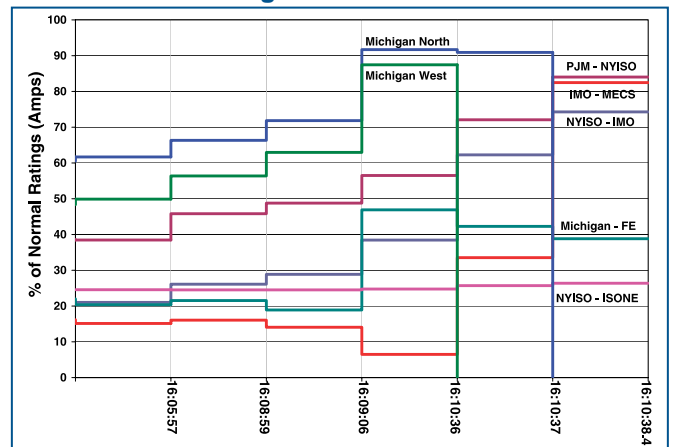
At 16:10:38.6 EDT, after the above transmission paths into Michigan and Ohio failed, the power that had been flowing at modest levels into Michigan from Ontario suddenly jumped in magnitude. While flows from Ontario into Michigan had been in the 250 to 350 MW range since 16:10:09.06 EDT, with this new surge they peaked at 3,700 MW at 16:10:39 EDT (Figure 6.16). Electricity moved along a giant loop through Pennsylvania and into New York and Ontario and then into Michigan via the remaining transmission path to serve the combined loads of Cleveland, Toledo, and Detroit. This sudden large change in power flows drastically lowered voltage and increased current levels on the transmission lines along the Pennsylvania-New York transmission interface.

This was a power surge of large magnitude, so frequency was not the same across the Eastern Interconnection. As Figure 6.16 shows, the power swing resulted in a rapid rate of voltage decay. Flows into Detroit exceeded 3,700 MW and 1,500 MVAr—the power surge was draining real power out of the northeast, causing voltages in Ontario and New York to drop. At the same time, local voltages in the Detroit area were plummeting because Detroit had already lost 500 MW of local generation. Detroit would soon lose synchronism

and black out (as evidenced by the rapid power oscillations decaying after 16:10:43 EDT).

Figure 6.15. Michigan Lines Trip and Ohio Separates from Pennsylvania, 16:10:36 to 16:10:38.6 EDT
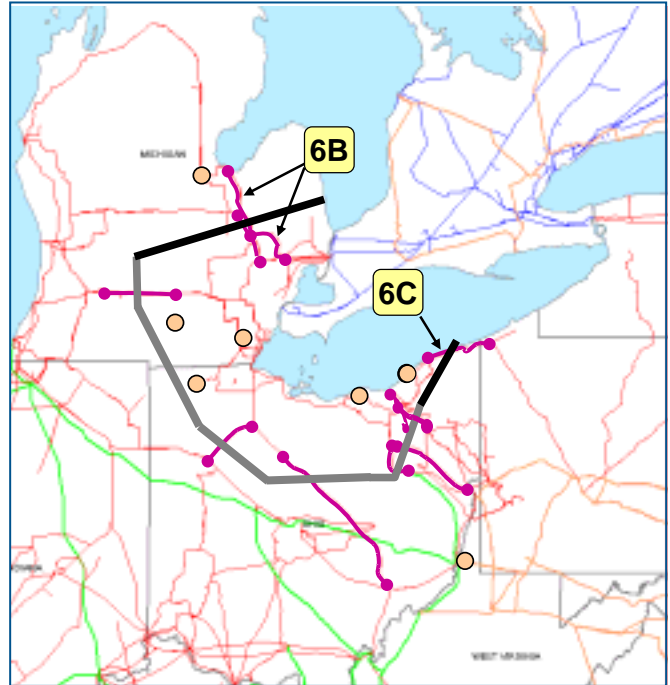
Modeling the Cascade

Computer modeling of the cascade built upon the modeling conducted of the pre-cascade system conditions described in Chapter 5. That earlier modeling developed steady-state load flow and voltage analyses for the entire Eastern Interconnection from 15:00 to 16:05:50 EDT. The dynamic modeling used the steady state load flow model for 16:05:50 as the starting point to simulate the cascade. Dynamic modeling conducts a series of load flow analyses, moving from one set of system conditions to another in steps one-quarter of a cycle long—in other words, to move one second from 16:10:00 to 16:10:01 requires simulation of 240 separate time slices.

The model used a set of equations that incorporate the physics of an electrical system. It contained detailed sub-models to reflect the characteristics of loads, under-frequency load-shedding, protective relay operations, generator operations (including excitation systems and governors), static VAr compensators and other FACTS devices, and transformer tap changers.

The modelers compared model results at each moment to actual system data for that moment to

verify a close correspondence for line flows and voltages. If there was too much of a gap between modeled and actual results, they looked at the timing of key events to see whether actual data might have been mis-recorded, or whether the modeled variance for an event not previously recognized as significant might influence the outcome. Through 16:10:40 EDT, the team achieved very close benchmarking of the model against actual results.

The modeling team consisted of industry members from across the Midwest, Mid-Atlantic and NPCC areas. All have extensive electrical engineering and/or mathematical training and experience as system planners for short- or long-term operations.
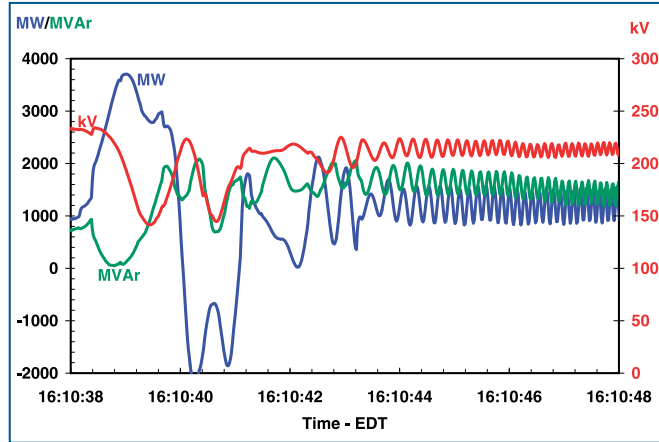
This modeling allows the team to verify its hypotheses as to why particular events occurred and the relationships between different events over time. It allows testing of many "what if" scenarios and alternatives, to determine whether a change in system conditions might have produced a different outcome.

Just before the Argenta-Battle Creek trip, when Michigan separated west to east at 16:10:37 EDT, almost all of the generators in the eastern interconnection were moving in synchronism with the overall grid frequency of 60 Hertz (shown at the bottom of Figure 6.17), but when the swing started, those machines absorbed some of its energy as they attempted to adjust and resynchronize with the rapidly changing frequency. In many cases, this adjustment was unsuccessful and the generators tripped out from milliseconds to several seconds thereafter.

The Perry-Ashtabula-Erie West 345-kV line trip at 16:10:38.6 EDT was the point when the Northeast entered a period of transient instability and a loss of generator synchronism. Between 16:10:38 and 16:10:41 EDT, the power swings caused a sudden extraordinary increase in system frequency, hitting 60.7 Hz at Lambton and 60.4 Hz at Niagara.

Because the demand for power in Michigan, Ohio, and Ontario was drawing on lines through New York and Pennsylvania, heavy power flows were moving northward from New Jersey over the New York tie lines to meet those power demands, exacerbating the power swing. Figure 6.17 shows actual net line flows summed across the interfaces between the main regions affected by these swings—Ontario into Michigan, New York into Ontario, New York into New England, and PJM into New York. This shows clearly that the power swings did not move in unison across every interface at every moment, but varied in magnitude and direction. This occurred for two reasons. First, the availability of lines to complete the path across

Figure 6.16. Active and Reactive Power and Voltage from Ontario into Detroit

Figure 6.17. Measured Power Flows and Frequency Across Regional Interfaces, 16:10:30 to 16:11:00 EDT, with Key Events in the Cascade
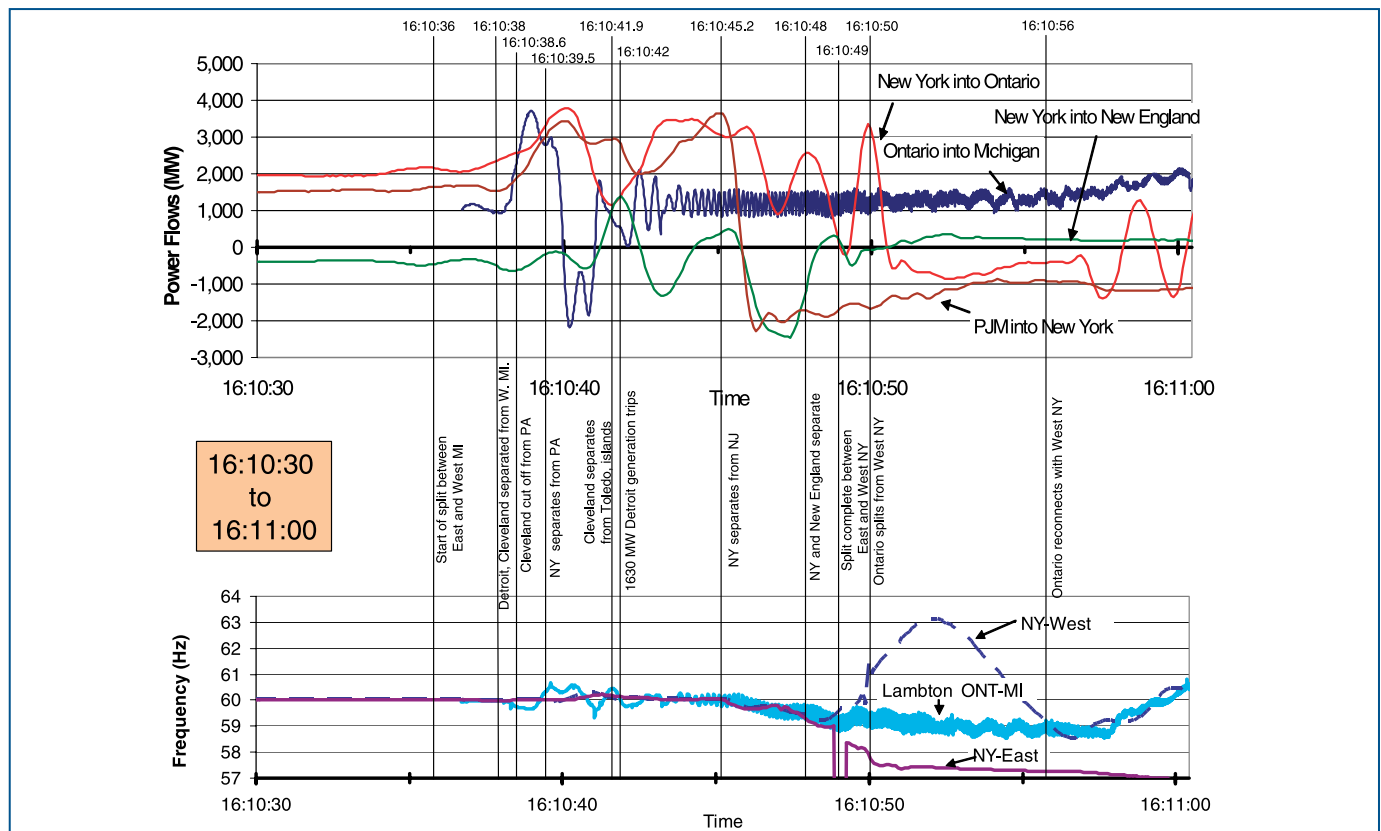
each interface varied over time, as did the amount of load that drew upon each interface, so net flows across each interface were not facing consistent demand with consistent capability as the cascade progressed. Second, the speed and magnitude of the swing was moderated by the inertia, reactive power capabilities, loading conditions and locations of the generators across the entire region.

After Cleveland was cut off from Pennsylvania and eastern power sources, Figure 6.17 shows the start of the dynamic power swing at 16:10:38.6. Because the loads of Cleveland, Toledo and Detroit (less the load already blacked out) were now hanging off Michigan and Ontario, this forced a gigantic shift in power flows to meet that demand. As noted above, flows from Ontario into Michigan increased from 1,000 MW to 3,700 MW shortly after the start of the swing, while flows from PJM into New York were close behind. But within two seconds from the start of the swing, at 16:10:40 EDT flows reversed and coursed back from Michigan into Ontario at the same time that frequency at the interface dropped, indicating that significant generation had been lost. Flows that had been westbound across the Ontario-Michigan interface by over 3,700 MW at 16:10:38.8 dropped down to 2,100 MW eastbound by 16:10:40, and then returned westbound starting at 16:10:40.5.

A series of circuits tripped along the border between PJM and the NYISO due to zone 1 impedance relay operations on overload and depressed voltage. The surge also moved into New England and the Maritimes region of Canada. The combination of the power surge and frequency rise caused 380 MW of pre-selected Maritimes generation to drop off-line due to the operation of the New Brunswick Power "Loss of Line 3001" Special Protection System. Although this system was designed to respond to failure of the 345-kV link between the Maritimes and New England, it operated in response to the effects of the power surge. The link remained intact during the event.

6D) Conditions in Northern Ohio and Eastern Michigan Degraded Further, With More Transmission Lines and Power Plants Failing: 16:10:39 to 16:10:46 EDT

Line trips in Ohio and eastern Michigan:

16:10:39.5 EDT: Bay Shore-Monroe 345-kV line

16:10:39.6 EDT: Allen Junction-Majestic-Monroe 345-kV line

16:10:40.0 EDT: Majestic-Lemoyne 345-kV line

Majestic 345-kV Substation: one terminal opened sequentially on all 345-kV lines

16:10:41.8 EDT: Fostoria Central-Galion 345-kV line

16:10:41.911 EDT: Beaver-Davis Besse 345-kV line

Under-frequency load-shedding in Ohio:

FirstEnergy shed 1,754 MVA load

AEP shed 133 MVA load

Seven power plants, for a total of 3,294 MW of generation, tripped off-line in Ohio:

16:10:42 EDT: Bay Shore Units 1-4 (551 MW near Toledo) tripped on over-excitation

16:10:40 EDT: Lakeshore unit 18 (156 MW, near Cleveland) tripped on under-frequency

16:10:41.7 EDT: Eastlake 1, 2, and 3 units (304 MW total, near Cleveland) tripped on under-frequency

16:10:41.7 EDT: Avon Lake unit 9 (580 MW, near Cleveland) tripped on under-frequency

16:10:41.7 EDT: Perry 1 nuclear unit (1,223 MW, near Cleveland) tripped on under-frequency

16:10:42 EDT: Ashtabula unit 5 (184 MW, near Cleveland) tripped on under-frequency

16:10:43 EDT: West Lorain units (296 MW) tripped on under-voltage

Four power plants producing 1,759 MW tripped off-line near Detroit:

16:10:42 EDT: Greenwood unit 1 tripped (253 MW) on low voltage, high current

16:10:41 EDT: Belle River unit 1 tripped (637 MW) on out-of-step

16:10:41 EDT: St. Clair unit 7 tripped (221 MW, DTE unit) on high voltage

16:10:42 EDT: Trenton Channel units 7A, 8 and 9 tripped (648 MW)

Back in northern Ohio, the trips of the Bay Shore-Monroe, Majestic-Lemoyne, Allen Junction-Majestic-Monroe 345-kV lines, and the Ashtabula 345/138-kV transformer cut off Toledo and Cleveland from the north, turning that area into an electrical island (Figure 6.18). Frequency in this large island began to fall rapidly. This caused a series of power plants in the area to trip

off-line due to the operation of under-frequency relays, including the Bay Shore units. When the Beaver-Davis Besse 345-kV line between Cleveland and Toledo tripped, it left the Cleveland area completely isolated and area frequency rapidly declined. Cleveland area load was disconnected by automatic under-frequency load-shedding (approximately 1,300 MW), and another 434 MW of load was interrupted after the generation remaining within this transmission "island" was tripped by under-frequency relays. This sudden load drop would contribute to the reverse power swing. In its own island, portions of Toledo blacked out from automatic under-frequency load-shedding but most of the Toledo load was restored by automatic reclosing of lines such as the East Lima-Fostoria Central 345-kV line and several lines at the Majestic 345-kV substation.

The Perry nuclear plant is in Ohio on Lake Erie, not far from the Pennsylvania border. The Perry plant was inside a decaying electrical island, and the plant tripped on under-frequency, as designed. A number of other units near Cleveland tripped off-line by under-frequency protection.

The tremendous power flow into Michigan, beginning at 16:10:38, occurred when Toledo and Cleveland were still connected to the grid only through Detroit. After the Bay Shore-Monroe line tripped at 16:10:39, Toledo-Cleveland were separated into their own island, dropping a large amount of load off the Detroit system. This left Detroit suddenly with excess generation, much of which was greatly accelerated in angle as the depressed voltage in Detroit (caused by the high demand in Cleveland) caused the Detroit units to pull nearly out of step. With the Detroit generators running at maximum mechanical output, they began to pull out of synchronous operation with the rest of the grid. When voltage in Detroit returned to near-normal, the generators could not fully pull back its rate of revolutions, and ended up producing excessive temporary output levels, still out of step with the system. This is evident in Figure 6.19, which shows at least two sets of generator "pole slips" by plants in the Detroit area between 16:10:40 EDT and 16:10:42 EDT. Several large units around Detroit—Belle River, St. Clair, Greenwood, Monroe, and Fermi—all tripped in response. After formation of the Cleveland-Toledo island at 16:10:40 EDT, Detroit frequency spiked to almost 61.7 Hz before dropping, momentarily equalized between the Detroit and Ontario systems, but Detroit frequency began to decay at 2 Hz/sec and the generators then experienced under-speed conditions.

Re-examination of Figure 6.17 shows the power swing from the northeast through Ontario into Michigan and northern Ohio that began at 16:10:37, and how it reverses and swings back around Lake Erie at 16:10:39 EDT. That return was caused by the combination of natural oscillations, accelerated by major load losses, as the northern Ohio system disconnected from Michigan. It caused a power flow change of 5,800 MW, from 3,700 MW westbound to 2,100 eastbound across the Ontario to Michigan border between 16:10:39.5 and 16:10:40 EDT. Since the system was now fully dynamic, this large oscillation eastbound would lead naturally to a rebound, which began at 16:10:40 EDT with an inflection point reflecting generation shifts between Michigan and Ontario and additional line losses in Ohio.

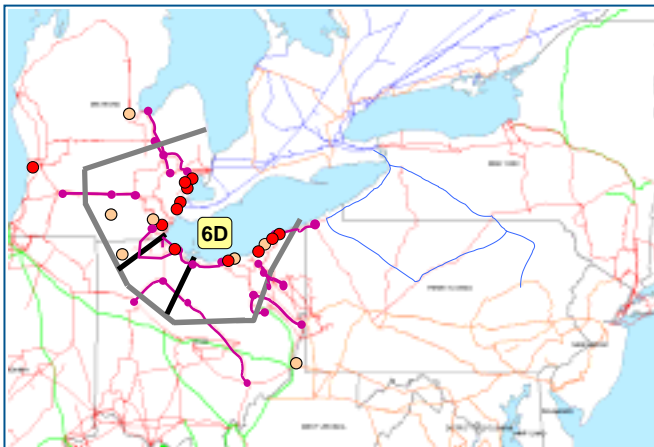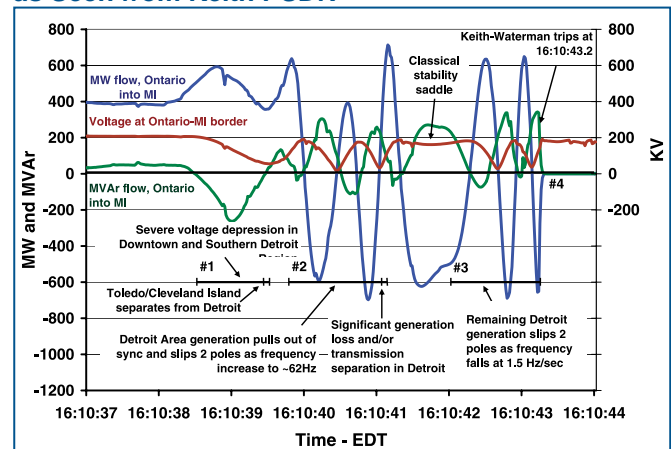**Figure 6.18. Cleveland and Toledo Islanded, 16:10:39 to 16:10:46 EDT**

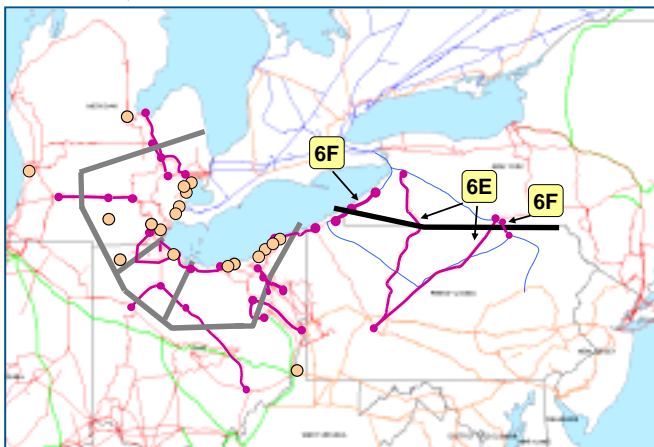**Figure 6.19. Generators Under Stress in Detroit, as Seen from Keith PSDR**

Western Pennsylvania Separated from New York: 16:10:39 EDT to 16:10:44 EDT

6E) 16:10:39 EDT, Homer City-Watercure Road 345 kV

16:10:39 EDT: Homer City-Stolle Road 345 kV

6F) 16:10:44 EDT: South Ripley-Erie East 230 kV, and South Ripley-Dunkirk 230 kV

16:10:44 EDT: East Towanda-Hillside 230 kV

Responding to the swing of power out of Michigan toward Ontario and into New York and PJM, zone 1 relays on the 345-kV lines separated Pennsylvania from New York (Figure 6.20). Homer City-Watercure (177 miles or 285 km) and Homer City-Stolle Road (207 miles or 333 km) are very long lines and so have high impedance. Zone 1 relays do not have timers, and operate instantly when a power swing enters the relay target circle. For normal length lines, zone 1 relays have small target circles because the relay is measuring a less than the full length of the line—but for a long line the large line impedance enlarges the relay's target circle and makes it more likely to be hit by the power swing. The Homer City-Watercure and Homer City-Stolle Road lines do not have zone 3 relays.

Given the length and impedance of these lines, it was highly likely that they would trip and separate early in the face of such large power swings. Most of the other interfaces between regions are on short ties—for instance, the ties between New York and Ontario and Ontario to Michigan are only about 2 miles (3.2 km) long, so they are electrically very short and thus have much lower impedance and trip less easily than these long lines. A zone 1 relay target for a short line covers a small area so a power swing is less likely to enter the relay target circle at all, averting a zone 1 trip.

At 16:10:44 EDT, the northern part of the Eastern Interconnection (including eastern Michigan) was connected to the rest of the Interconnection at only two locations: (1) in the east through the 500-kV and 230-kV ties between New York and northeast New Jersey, and (2) in the west through the long and electrically fragile 230-kV transmission path connecting Ontario to Manitoba and Minnesota. The separation of New York from Pennsylvania (leaving only the lines from New Jersey into New York connecting PJM to the northeast) buffered PJM in part from these swings. Frequency was high in Ontario at that point, indicating that there was more generation than load, so much of this flow reversal never got past Ontario into New York.

6G) Transmission paths disconnected in New Jersey and northern Ontario, isolating the northeast portion of the Eastern Interconnection: 16:10:43 to 16:10:45 EDT

16:10:43 EDT: Keith-Waterman 230-kV line tripped

16:10:45 EDT: Wawa-Marathon 230-kV lines tripped

16:10:45 EDT: Branchburg-Ramapo 500-kV line tripped

At 16:10:43 EDT, eastern Michigan was still connected to Ontario, but the Keith-Waterman 230-kV line that forms part of that interface disconnected due to apparent impedance (Figure 6.21). This put more power onto the remaining interface between Ontario and Michigan, but

Figure 6.20. Western Pennsylvania Separates from New York, 16:10:39 EDT to 16:10:44 EDT

Figure 6.21. Northeast Separates from Eastern Interconnection, 16:10:45 EDT
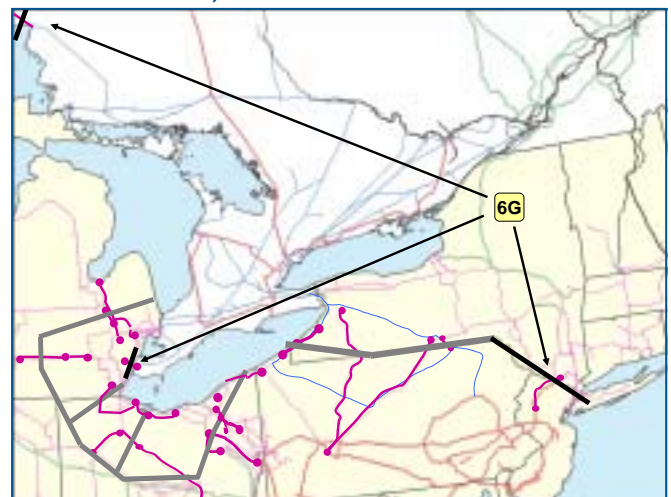
triggered sustained oscillations in both power flow and frequency along the remaining 230-kV line.

At 16:10:45 EDT, northwest Ontario separated from the rest of Ontario when the Wawa-Marathon 230-kV lines (104 miles or 168 km long) disconnected along the northern shore of Lake Superior, tripped by zone 1 distance relays at both ends. This separation left the loads in the far northwest portion of Ontario connected to the Manitoba and Minnesota systems, and protected them from the blackout.

The 69-mile (111 km) long Branchburg-Ramapo 500-kV line and Ramapo transformer between New Jersey and New York was the last major transmission path remaining between the Eastern Interconnection and the area ultimately affected by the blackout. Figure 6.22 shows how that line disconnected at 16:10:45 EDT, along with other underlying 230 and 138-kV lines in northeast New Jersey. Branchburg–Ramapo was carrying over 3,000 MVA and 4,500 amps with voltage at 79% before it tripped, either on a high-speed swing into zone 1 or on a direct transfer trip. The investigation team is still examining why the higher impedance 230-kV overhead lines tripped while the underground Hudson-Farragut 230-kV cables did not; the available data suggest that the notably lower impedance of underground cables made these less vulnerable to the electrical strain placed on the system.

This left the northeast portion of New Jersey connected to New York, while Pennsylvania and the rest of New Jersey remained connected to the rest of the Eastern Interconnection. Within northeast New Jersey, the separation occurred along the 230-kV corridors which are the main supply feeds into the northern New Jersey area (the two Roseland-Athenia circuits and the Linden-Bayway circuit). These circuits supply the large customer load in northern New Jersey and are a primary route for power transfers into New York City, so they are usually more highly loaded than other interfaces. These lines tripped west and south of the large customer loads in northeast New Jersey.

The separation of New York, Ontario, and New England from the rest of the Eastern Interconnection occurred due to natural breaks in the system and automatic relay operations, which performed exactly as they were designed to. No human intervention occurred by operators at PJM headquarters or elsewhere to effect this split. At this point, the Eastern Interconnection was divided into two major sections. To the north and east of the separation point lay New York City, northern New Jersey, New York state, New England, the Canadian Maritime Provinces, eastern Michigan, the majority of Ontario, and the Québec system.

The rest of the Eastern Interconnection, to the south and west of the separation boundary, was not seriously affected by the blackout. Frequency in the Eastern Interconnection was 60.3 Hz at the time of separation; this means that approximately 3,700 MW of excess generation that was on-line to export into the northeast was now in the main Eastern Island, separated from the load it had been serving. This left the northeast island with even less in-island generation on-line as it attempted to rebalance in the next phase of the cascade.

Figure 6.22. PJM to New York Interties Disconnect
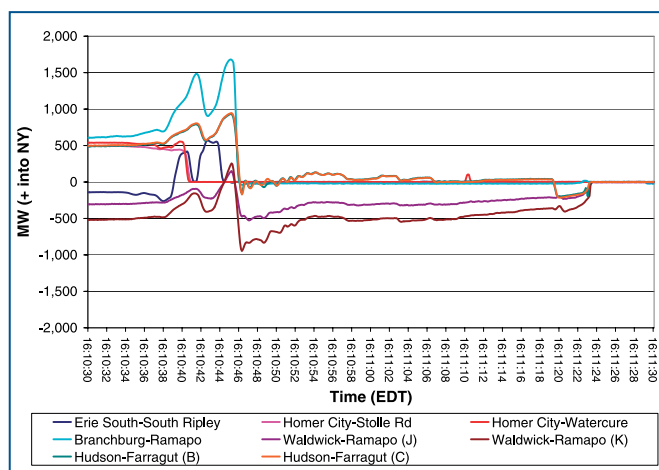
Note: The data in this figure come from the NYISO Energy Management System SDAC high speed analog system, which records 10 samples per second.

Phase 7:
Several Electrical Islands Formed in Northeast U.S. and Canada: 16:10:46 EDT to 16:12 EDT

Overview of This Phase

During the next 3 seconds, the islanded northern section of the Eastern Interconnection broke apart internally. Figure 6.23 illustrates the events of this phase.

7A) New York-New England upstate transmission lines disconnected: 16:10:46 to 16:10:47 EDT

7B) New York transmission system split along Total East interface: 16:10:49 EDT

7C) The Ontario system just west of Niagara Falls and west of St. Lawrence separated from the western New York island: 16:10:50 EDT

7D) Southwest Connecticut separated from New York City: 16:11:22 EDT

7E) Remaining transmission lines between Ontario and eastern Michigan separated: 16:11:57 EDT

By this point most portions of the affected area were blacked out.

If the 6th phase of the cascade was about dynamic system oscillations, the last phase is a story of the search for balance between loads and generation. Here it is necessary to understand three matters related to system protection—why the blackout stopped where it did, how and why under-voltage and under-frequency load-shedding work, and what happened to the generators on August 14 and why. These matter because loads and generation must ultimately balance in real-time to remain stable. When the grid is breaking apart into islands, if generators stay on-line longer, then the better the chances to keep the lights on within each island and restore service following a blackout; so automatic load-shedding, transmission relay protections and generator protections must avoid premature tripping. They must all be coordinated to reduce the likelihood of system break-up, and once break-up occurs, to maximize an island's chances for electrical survival.

Why the Blackout Stopped Where It Did

Extreme system conditions can damage equipment in several ways, from melting aluminum conductors (excessive currents) to breaking turbine blades on a generator (frequency excursions). The power system is designed to ensure that if conditions on the grid (excessive or inadequate voltage, apparent impedance or frequency) threaten the safe operation of the transmission lines, transformers, or power plants, the threatened equipment automatically separates from the network to protect itself from physical damage. Relays are the devices that effect this protection.

Generators are usually the most expensive units on an electrical system, so system protection schemes are designed to drop a power plant off the system as a self-protective measure if grid conditions become unacceptable. This protective

measure leaves the generator in good condition to help rebuild the system once a blackout is over and restoration begins. When unstable power swings develop between a group of generators that are losing synchronization (unable to match frequency) with the rest of the system, one effective way to stop the oscillations is to stop the flows entirely by disconnecting the unstable generators from the remainder of the system. The most common way to protect generators from power oscillations is for the transmission system to detect the power swings and trip at the locations detecting the swings—ideally before the swing reaches critical levels and harms the generator or the system.

On August 14, the cascade became a race between the power surges and the relays. The lines that tripped first were generally the longer lines with relay settings using longer apparent impedance tripping zones and normal time settings. On August 14, relays on long lines such as the Homer City-Watercure and the Homer City-Stolle Road 345-kV lines in Pennsylvania, that are not highly integrated into the electrical network, tripped quickly and split the grid between the sections that blacked out and those that recovered without further propagating the cascade. This same phenomenon was seen in the Pacific Northwest blackouts of 1996, when long lines tripped before more networked, electrically supported lines.

Transmission line voltage divided by its current flow is called "apparent impedance." Standard transmission line protective relays continuously measure apparent impedance. When apparent impedance drops within the line's protective relay set-points for a given period of time, the relays trip

Figure 6.23. New York and New England Separate, Multiple Islands Form
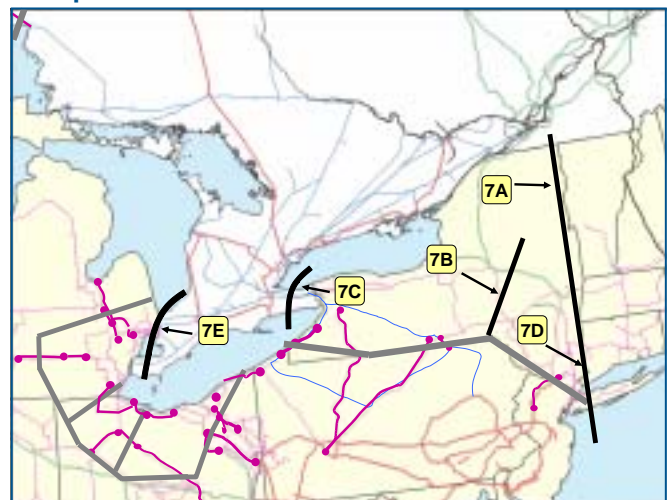
the line. The vast majority of trip operations on lines along the blackout boundaries between PJM and New York (for instance) show high-speed relay targets which indicate that a massive power surge caused each line to trip. To the relays, this power surge altered the voltages and currents enough that they appeared to be faults. The power surge was caused by power flowing to those areas that were generation-deficient (Cleveland, Toledo and Detroit) or rebounding back. These flows occurred purely because of the physics of power flows, with no regard to whether the power flow had been scheduled, because power flows from areas with excess generation into areas that were generation-deficient.

Protective relay settings on transmission lines operated as they were designed and set to behave on August 14. In some cases line relays did not trip in the path of a power surge because the apparent impedance on the line was not low enough—not because of the magnitude of the current, but rather because voltage on that line was high enough that the resulting impedance was adequate to avoid entering the relay's target zone. Thus relative voltage levels across the northeast also affected which areas blacked out and which areas stayed on-line.

In the U.S. Midwest, as voltage levels declined many generators in the affected area were operating at maximum reactive power output before the blackout. This left the system little slack to deal with the low voltage conditions by ramping up more generators to higher reactive power output levels, so there was little room to absorb any system "bumps" in voltage or frequency. In contrast, in the northeast—particularly PJM, New York, and ISO-New England—operators were anticipating high power demands on the afternoon of August 14, and had already set up the system to maintain higher voltage levels and therefore had more reactive reserves on-line in anticipation of later afternoon needs. Thus, when the voltage and frequency swings began, these systems had reactive power readily available to help buffer their areas against potential voltage collapse without widespread generation trips.

The investigation team has used simulation to examine whether special protection schemes, designed to detect an impending cascade and separate the grid at specific interfaces, could have been or should be set up to stop a power surge and prevent it from sweeping through an interconnection and causing the breadth of line and generator trips and islanding that occurred that day. The team has concluded that such schemes would have been ineffective on August 14.

Under-Frequency and Under-Voltage Load-Shedding

Automatic load-shedding measures are designed into the electrical system to operate as a last resort, under the theory that it is wise to shed some load in a controlled fashion if it can forestall the loss of a great deal of load to an uncontrollable cause. Thus there are two kinds of automatic load-shedding installed in North America—under-voltage load-shedding, which sheds load to prevent local area voltage collapse, and under-frequency load-shedding, which is designed to rebalance load and generation within an electrical island once it has been created by a system disturbance.

Automatic under-voltage load-shedding (UVLS) responds directly to voltage conditions in a local area. UVLS drops several hundred MW of load in pre-selected blocks within urban load centers, triggered in stages when local voltage drops to a designated level—likely 89 to 92% or even higher—with a several second delay. The goal of a UVLS scheme is to eliminate load in order to restore reactive power relative to demand, to prevent voltage collapse and contain a voltage problem within a local area rather than allowing it to spread in geography and magnitude. If the first load-shed step does not allow the system to rebalance, and voltage continues to deteriorate, then the next block of UVLS is dropped. Use of UVLS is not mandatory, but is done at the option of the control area and/or reliability council. UVLS schemes and trigger points should be designed to respect the local area's system vulnerabilities, based on voltage collapse studies. As noted in Chapter 4, there is no UVLS system in place within Cleveland and Akron; had such a scheme been implemented before August, 2003, shedding 1,500 MW of load in that area before the loss of the Sammis-Star line might have prevented the cascade and blackout.

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In contrast to UVLS, automatic under-frequency load-shedding (UFLS) is designed for use in extreme conditions to stabilize the balance between generation and load after an electrical island has been formed, dropping enough load to allow frequency to stabilize within the island. All synchronous generators in North America are designed to operate at 60 cycles per second

(Hertz) and frequency reflects how well load and generation are balanced—if there is more load than generation at any moment, frequency drops below 60 Hz, and it rises above that level if there is more generation than load. By dropping load to match available generation within the island, UFLS is a safety net that helps to prevent the complete blackout of the island, which allows faster system restoration afterward. UFLS is not effective if there is electrical instability or voltage collapse within the island.

Today, UFLS installation is a NERC requirement, designed to shed at least 25-30% of the load in steps within each reliability coordinator region. These systems are designed to drop pre-designated customer load automatically if frequency gets too low (since low frequency indicates too little generation relative to load), starting generally when frequency reaches 59.3 Hz. Progressively more load is set to drop as frequency levels fall farther. The last step of customer load shedding is set at the frequency level just above the set point for generation under-frequency protection relays (57.5 Hz), to prevent frequency from falling so low that generators could be damaged (see Figure 2.4).

In NPCC, following the Northeast blackout of 1965, the region adopted automatic under-frequency load-shedding criteria and manual load-shedding within ten minutes to prevent a recurrence of the cascade and better protect system equipment from damage due to a high-speed system collapse. Under-frequency load-shedding triggers vary by regional reliability council—New York and all of the Northeast Power Coordinating Council, plus the Mid-Atlantic Area Council use 59.3 Hz as the first step for UFLS, while ECAR uses 59.5 Hz as their first step for UFLS.

The following automatic UFLS operated on the afternoon of August 14:

◆ Ohio shed over 1,883 MVA beginning at 16:10:39 EDT

◆ Michigan shed a total of 2,835 MW

◆ New York shed a total of 10,648 MW in numerous steps, beginning at 16:10:48

◆ PJM shed a total of 1,324 MVA in 3 steps in northern New Jersey beginning at 16:10:48 EDT

◆ Ontario shed a total of 7,800 MW in 2 steps, beginning at 16:10:4

◆ New England shed a total of 1,098 MW.

It must be emphasized that the entire northeast system was experiencing large scale, dynamic oscillations in this period. Even if the UFLS and generation had been perfectly balanced at any moment in time, these oscillations would have made stabilization difficult and unlikely.

Why the Generators Tripped Off

At least 265 power plants with more than 508 individual generating units shut down in the August 14 blackout. These U.S. and Canadian plants can be categorized as follows:

By reliability coordination area:

◆ Hydro Québec, 5 plants (all isolated onto the Ontario system)[4]

◆ Ontario, 92 plants

◆ ISO-New England, 31 plants

◆ MISO, 32 plants

◆ New York ISO, 70 plants

◆ PJM, 35 plants

By type:

◆ Conventional steam units, 66 plants (37 coal)

◆ Combustion turbines, 70 plants (37 combined cycle)

◆ Nuclear, 10 plants—7 U.S. and 3 Canadian, totaling 19 units (the nuclear unit outages are discussed in Chapter 8)

◆ Hydro, 101

◆ Other, 18.

Within the overall cascade sequence, 29 (6%) generators tripped between the start of the cascade at 16:05:57 (the Sammis-Star trip) and the split between Ohio and Pennsylvania at 16:10:38.6 EDT (Erie West-Ashtabula-Perry), which triggered the first big power swing. These trips were caused by the generators' protective relays responding to overloaded transmission lines, so many of these trips were reported as under-voltage or over-current. The next interval in the cascade was as the portions of the grid lost synchronism, from 16:10:38.6 until 16:10:45.2 EDT, when Michigan-New York-Ontario-New England separated from the rest of the Eastern Interconnection. Fifty more generators (10%) tripped as the islands formed, particularly due to changes in configuration, loss of synchronism, excitation system failures, with some under-frequency and under-voltage. In the third phase of generator losses, 431 generators (84%) tripped after the islands formed,

many at the same time that under-frequency load-shedding was occurring. This is illustrated in Figure 6.24. It is worth noting, however, that many generators did not trip instantly after the trigger condition that led to the trip—rather, many relay protective devices operate on time delays of milliseconds to seconds in duration, so that a generator that reported tripping at 16:10:43 on under-voltage or "generator protection" might have experienced the trigger for that condition several seconds earlier.

The high number of generators that tripped before formation of the islands helps to explain why so much of the northeast blacked out on August 14—many generators had pre-designed protection points that shut the unit down early in the cascade, so there were fewer units on-line to prevent island formation or to maintain balance between load and supply within each island after it formed. In particular, it appears that

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some generators tripped to protect the units from conditions that did not justify their protection, and many others were set to trip in ways that were not coordinated with the region's under-frequency load-shedding, rendering that UFLS scheme less effective. Both factors compromised successful islanding and precipitated the blackouts in Ontario and New York.

Most of the unit separations fell in the category of consequential tripping—they tripped off-line in response to some outside condition on the grid, not because of any problem internal to the plant. Some generators became completely removed from all loads; because the fundamental operating principle of the grid is that load and generation must balance, if there was no load to be served the power plant shut down in response to over-speed and/or over-voltage protection schemes. Others were overwhelmed because they were among a few power plants within an electrical island, and were suddenly called on to serve huge customer loads, so the imbalance caused them to trip on under-frequency and/or under-voltage protection. A few were tripped by special protection schemes that activated on excessive frequency or loss of pre-studied major transmission elements known to require large blocks of generation rejection.

The large power swings and excursions of system frequency put all the units in their path through a sequence of major disturbances that shocked several units into tripping. Plant controls had actuated fast governor action on several of these to turn back the throttle, then turn it forward, only to turn
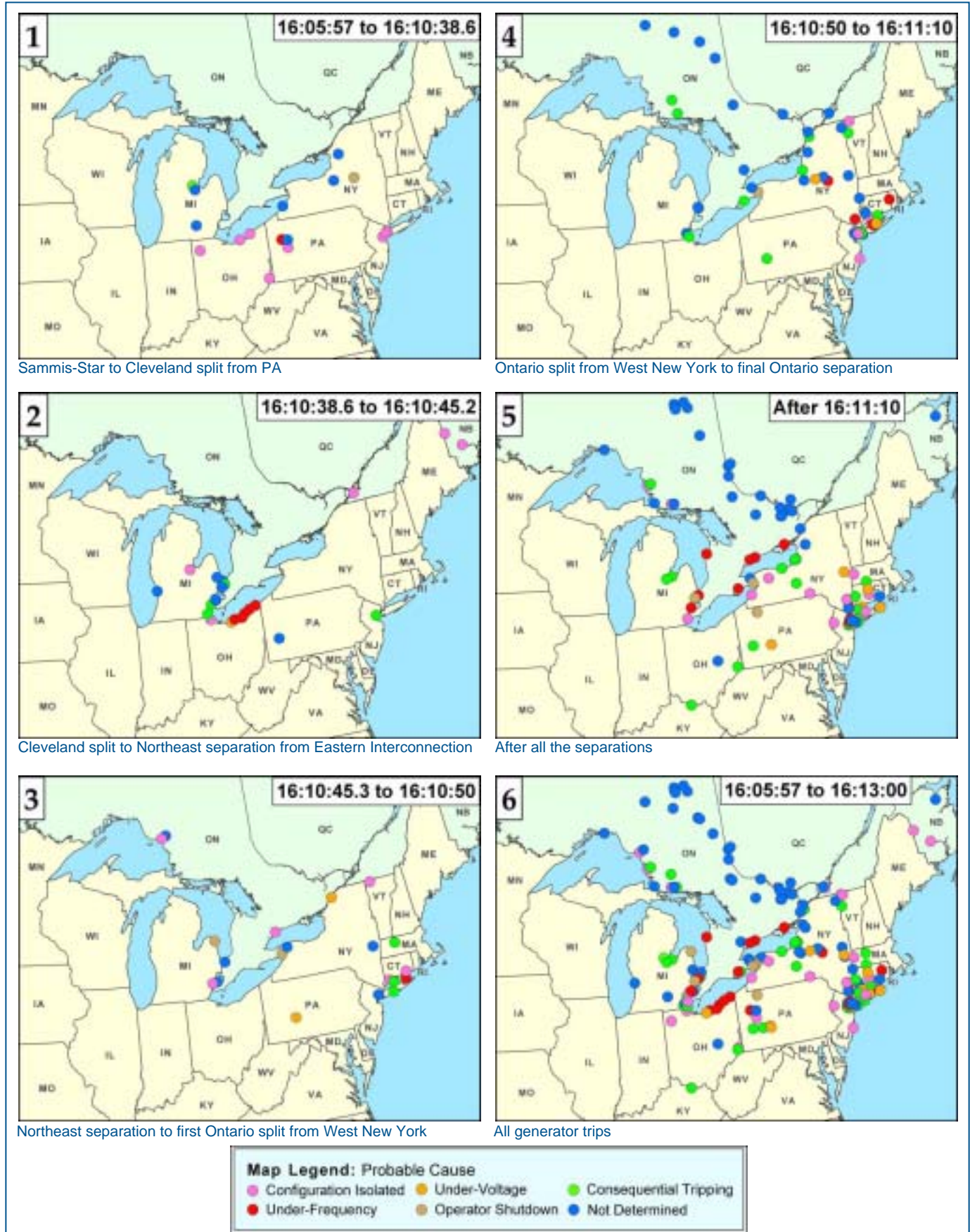
it back again as some frequencies changed several times by as much as 3 Hz (about 100 times normal deviations). Figure 6.25 is a plot of the MW output and frequency for one large unit that nearly survived the disruption but tripped when in-plant hydraulic control pressure limits were eventually violated. After the plant control system called for shutdown, the turbine control valves closed and the generator electrical output ramped down to a preset value before the field excitation tripped and the generator breakers opened to disconnect the unit from the system. This also illustrates the time lag between system events and the generator reaction—this generator was first disturbed by system conditions at 16:10:37, but did not trip until 16:11:47, over a minute later.

Under-frequency (10% of the generators reporting) and under-voltage (6%) trips both reflect responses to system conditions. Although combustion turbines in particular are designed with under-voltage relay protection, it is not clear why this is needed. An under-voltage condition by itself and over a set time period may not necessarily be a generator hazard (although it could affect plant auxiliary systems). Some generator under-voltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%.

An excitation failure is closely related to a voltage trip. As local voltages decreased, so did frequency. Over-excitation operates on a calculation of volts/hertz, so as frequency declines faster than voltage over-excitation relays would operate. It is not clear that these relays were coordinated with each machine's exciter controls, to be sure that it was protecting the machine for the proper range of its control capabilities. Large units have two relays to detect volts/Hz—one at the generator and one at the transformer, each with a slightly different volts/Hz setting and time delay. It is possible that these settings can cause a generator to trip within a generation-deficient island as frequency is attempting to rebalance, so these settings should be carefully evaluated.

The Eastlake 5 trip at 13:31 EDT was an excitation system failure—as voltage fell at the generator bus, the generator tried to increase quickly its production of voltage on the AC winding of the machine quickly. This caused the generator's excitation protection scheme to trip the plant off to

Figure 6.24. Generator Trips by Time and Cause

1 — 16:05:57 to 16:10:38.6

Sammis-Star to Cleveland split from PA

4 — 16:10:50 to 16:11:10

Ontario split from West New York to final Ontario separation

2 — 16:10:38.6 to 16:10:45.2

Cleveland split to Northeast separation from Eastern Interconnection

5 — After 16:11:10

After all the separations

3 — 16:10:45.3 to 16:10:50

Northeast separation to first Ontario split from West New York

6 — 16:05:57 to 16:13:00

All generator trips

Map Legend: Probable Cause
- Configuration Isolated
- Under-Frequency
- Under-Voltage
- Operator Shutdown
- Consequential Tripping
- Not Determined

protect its windings and coils from over-heating. Several of the other generators which tripped early in the cascade came off under similar circumstances as excitation systems were over-stressed to hold voltages up. Seventeen generators reported tripping for over-excitation. Units that trip for a cause related to frequency should be evaluated to determine how the unit frequency triggers coordinate with the region's under-frequency load-shedding scheme, to assure that the generator trips are sequenced to follow rather than precede load-shedding. After UFLS operates to drop a large block of load, frequency continues to decline for several cycles before rebounding, so it is necessary to design an adequate time delay into generators' frequency-related protections to keep it on-line long enough to help rebalance against the remaining load.

Fourteen generators reported tripping for under-excitation (also known as loss of field), which protects the generator from exciter component failures. This protection scheme can operate on stable as well as transient power swings, so should be examined to determine whether the protection settings are appropriate. Eighteen units—primarily combustion turbines—reported over-current as the reason for relay operation.

Some generators in New York failed in a way that exacerbated frequency decay. A generator that tripped due to a boiler or steam problem may have done so to prevent damage due to over-speed and limit impact to the turbine-generator shaft when the breakers are opened, and it will attempt to maintain its synchronous speed until the generator is tripped. To do this, the mechanical part of the system would shut off the steam flow. This causes the generator to consume a small amount

Figure 6.25. Events at One Large Generator During the Cascade

of power off the grid to support the unit's orderly slow-down and trip due to reverse power flow. This is a standard practice to avoid turbine over-speed. Also within New York, 16 gas turbines totaling about 400 MW reported tripping for loss of fuel supply, termed "flame out." These units' trips should be better understood.

Another reason for power plant trips was actions or failures of plant control systems. One common cause in this category was a loss of sufficient voltage to in-plant loads. Some plants run their internal cooling and processes (house electrical load) off the generator or off small, in-house auxiliary generators, while others take their power off the main grid. When large power swings or voltage drops reached these plants in the latter category, they tripped off-line because the grid could not supply the plant's in-house power needs reliably. At least 17 units reported tripping due to loss of system configuration, including the loss of a transmission or distribution line to serve the in-plant loads. Some generators were tripped by their operators.

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Unfortunately, 40% of the generators that went off-line during or after the cascade did not provide useful information on the cause of tripping in their response to the NERC investigation data request. While the responses available offer significant and valid information, the investigation team will never be able to fully analyze and explain why so many generators tripped off-line so early in the cascade, contributing to the speed and extent of the blackout. It is clear that every generator should have some minimum of protection for stator differential, loss of field, and out-of-step protection, to disconnect the unit from the grid when it is not performing correctly, and also protection for protect the generator from extreme conditions on the grid that could cause catastrophic damage to the generator. These protections should be set tight enough to protect the unit from the grid, but also wide enough to assure that the unit remains connected to the grid as long as possible. This coordination is a risk management issue that must balance the needs of the grid and customers relative to the needs of the individual assets.

> **Recommendation 21, page 158**
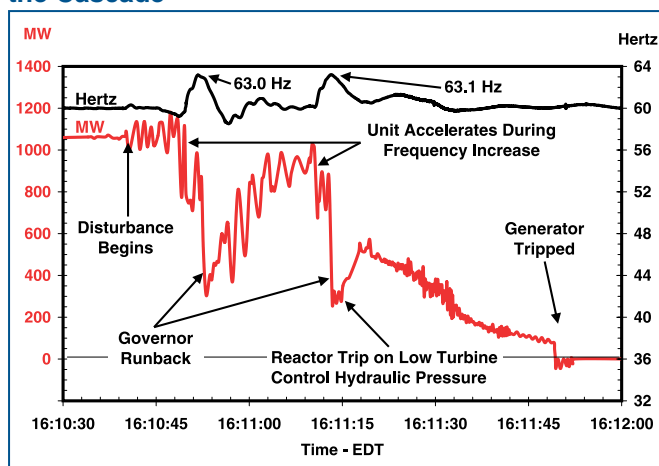
Key Phase 7 Events

Electric loads and flows do not respect political boundaries. After the blackout of 1965, as loads

grew within New York City and neighboring northern New Jersey, the utilities serving the area deliberately increased the integration between the systems serving this area to increase the flow capability into New York and the reliability of the system as a whole. The combination of the facilities in place and the pattern of electrical loads and flows on August 14 caused New York to be tightly linked electrically to northern New Jersey and southwest Connecticut, and moved the weak spots on the grid out past this combined load and network area.

Figure 6.26 gives an overview of the power flows and frequencies in the period 16:10:45 EDT through 16:11:00 EDT, capturing most of the key events in Phase 7.

7A) New York-New England Transmission Lines Disconnected: 16:10:46 to 16:10:54 EDT

Over the period 16:10:46 EDT to 16:10:54 EDT, the separation between New England and New York occurred. It occurred along five of the northern tie lines, and seven lines within southwest Connecticut. At the time of the east-west separation in New York at 16:10:49 EDT, New England was isolated from the eastern New York island. The only remaining tie was the PV-20 circuit connecting New England and the western New York island, which tripped at 16:10:54 EDT. Because New England was exporting to New York before the disturbance across the southwest Connecticut tie, but importing on the Northwalk-Northport tie, the Pleasant Valley path opened east of Long Mountain—in other words, internal to southwest Connecticut—rather than along the actual New York-New England tie.[5] Immediately before the separation, the power swing out of New England occurred because the New England generators had increased output in response to the drag of power through Ontario and New York into Michigan and Ohio.[6] The power swings continuing through the region caused this separation, and caused Vermont to lose approximately 70 MW of load.

When the ties between New York and New England disconnected, most of the New England area along with Canada's Maritime Provinces (New Brunswick and Nova Scotia) became an island with generation and demand balanced close enough that it was able to remain operational. The New England system had been exporting close to

Figure 6.26. Measured Power Flows and Frequency Across Regional Interfaces, 16:10:45 to 16:11:30 EDT, with Key Events in the Cascade
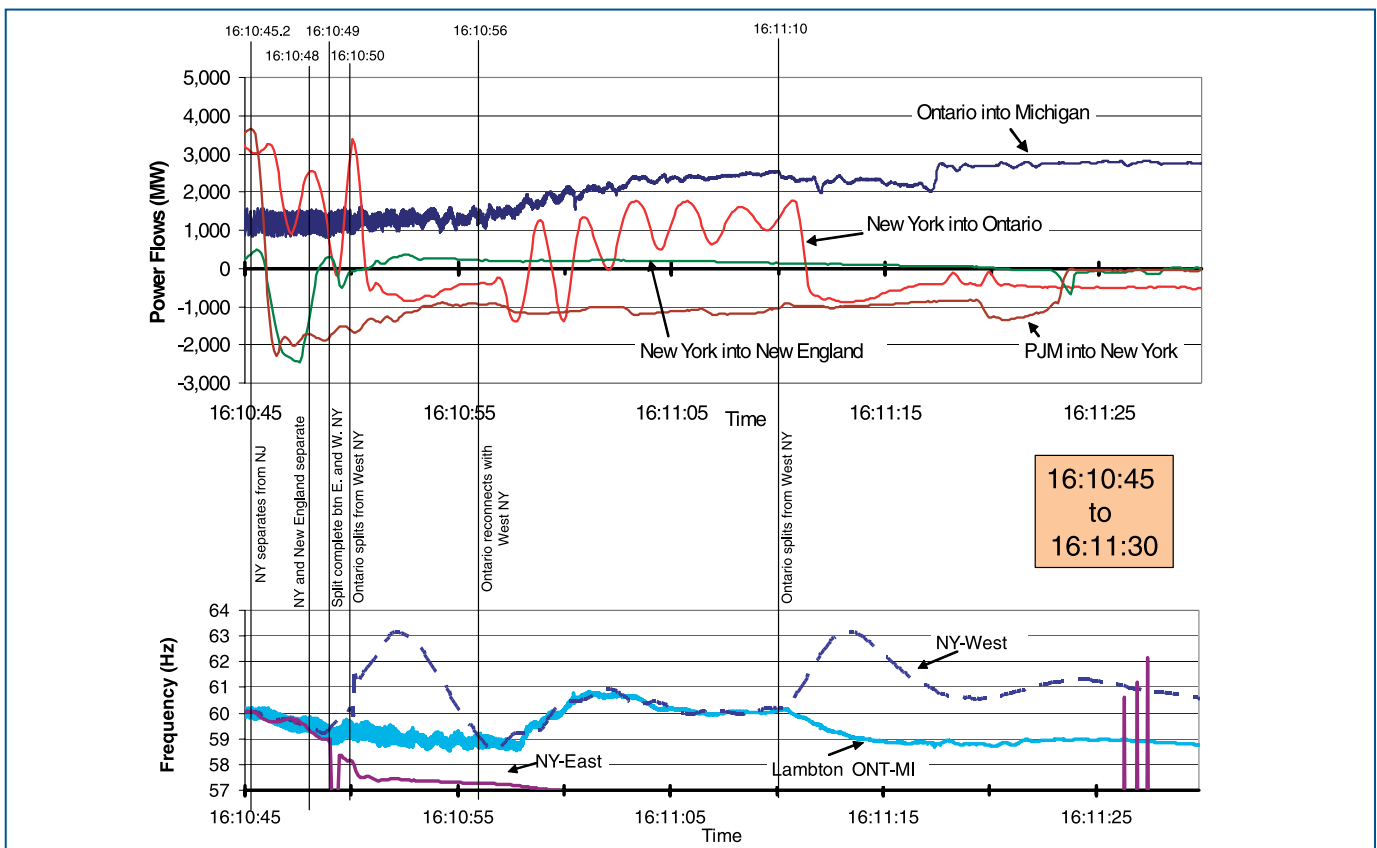
600 MW to New York, so it was relatively generation-rich and experienced continuing fluctuations until it reached equilibrium. Before the Maritimes and New England separated from the Eastern Interconnection at approximately 16:11 EDT, voltages became depressed across portions of New England and some large customers disconnected themselves automatically.[7] However, southwestern Connecticut separated from New England and remained tied to the New York system for about one minute.

While frequency within New England wobbled slightly and recovered quickly after 16:10:40 EDT, frequency of the New York-Ontario-Michigan-Ohio island fluctuated severely as additional lines, loads and generators tripped, reflecting the severe generation deficiency in Michigan and Ohio.

Due to its geography and electrical characteristics, the Québec system in Canada is tied to the remainder of the Eastern Interconnection via high voltage DC (HVDC) links instead of AC transmission lines. Québec was able to survive the power surges with only small impacts because the DC connections shielded it from the frequency swings.

7B) New York Transmission Split East-West: 16:10:49 EDT

The transmission system split internally within New York along the Total East interface, with the eastern portion islanding to contain New York City, northern New Jersey, and southwestern Connecticut. The eastern New York island had been importing energy, so it did not have enough surviving generation on-line to balance load. Frequency declined quickly to below 58.0 Hz and triggered 7,115 MW of automatic UFLS.[8] Frequency declined further, as did voltage, causing pre-designed trips at the Indian Point nuclear plant and other generators in and around New York City through 16:11:10 EDT. The western portion of New York remained connected to Ontario and eastern Michigan.

The electric system has inherent weak points that vary as a function of the characteristics of the physical lines and plants and the topology of the lines, loads and flows across the grid at any point in time. The weakest points on a system tend to be those points with the highest impedance, which routinely are long (over 50 miles or 80 km) overhead lines with high loading. When such lines have high-speed relay protections that may trip on high current and overloads in addition to true faults, they will trip out before other lines in the path of large power swings such as the 3,500 MW power surge that hit New York on August 14. New York's Total East and Central East interfaces, where the internal split occurred, are routinely among the most heavily loaded paths in the state and are operated under thermal, voltage and stability limits to respect their relative vulnerability and importance.

Examination of the loads and generation in the Eastern New York island indicates before 16:10:00 EDT, the area had been importing electricity and had less generation on-line than load. At 16:10:50 EDT, seconds after the separation along the Total East interface, the eastern New York area had experienced significant load reductions due to under-frequency load-shedding—Consolidated Edison, which serves New York City and surrounding areas, dropped over 40% of its load on automatic UFLS. But at this time, the system was still experiencing dynamic conditions—as illustrated in Figure 6.26, frequency was falling, flows and voltages were oscillating, and power plants were tripping off-line.

Had there been a slow islanding situation and more generation on-line, it might have been possible for the Eastern New York island to rebalance given its high level of UFLS. But the available information indicates that events happened so quickly and the power swings were so large that rebalancing would have been unlikely, with or without the northern New Jersey and southwest Connecticut loads hanging onto eastern New York. This was further complicated because the high rate of change in voltages at load buses reduced the actual levels of load shed by UFLS relative to the levels needed and expected.

The team could not find any way that one electrical region might have protected itself against the August 14 blackout, either at electrical borders or internally. The team also looked at whether it was possible to design special protection schemes to separate one region from its neighborings proactively, to buffer itself from a power swing before it hit. This was found to be inadvisable for two reasons: (1) as noted above, the act of separation itself could cause oscillations and dynamic instability that could be as damaging to the system as the swing it was protecting against; and (2) there was no event or symptom on August 14 that could be used to trigger such a protection scheme in time.

7C) The Ontario System Just West of Niagara Falls and West of St. Lawrence Separated from the Western New York Island: 16:10:50 EDT

At 16:10:50 EDT, Ontario and New York separated west of the Ontario/New York interconnection, due to relay operations which disconnected nine 230-kV lines within Ontario. These left most of Ontario isolated to the north. Ontario's large Beck and Saunders hydro stations, along with some Ontario load, the New York Power Authority's (NYPA) Niagara and St. Lawrence hydro stations, and NYPA's 765-kV AC interconnection to their HVDC tie with Québec, remained connected to the western New York system, supporting the demand in upstate New York.

From 16:10:49 to 16:10:50 EDT, frequency in Ontario declined below 59.3 Hz, initiating automatic under-frequency load-shedding (3,000 MW). This load-shedding dropped about 12% of Ontario's remaining load. Between 16:10:50 EDT and 16:10:56 EDT, the isolation of Ontario's 2,300 MW Beck and Saunders hydro units onto the western New York island, coupled with under-frequency load-shedding in the western New York island, caused the frequency in this island to rise to 63.4 Hz due to excess generation relative to the load within the island (Figure 6.27). The high frequency caused trips of five of the U.S. nuclear units within the island, and the last one tripped on the second frequency rise.

Three of the tripped 230-kV transmission circuits near Niagara automatically reconnected Ontario to New York at 16:10:56 EDT by reclosing. Even with these lines reconnected, the main Ontario island (still attached to New York and eastern Michigan) was then extremely deficient in generation, so its frequency declined towards 58.8 Hz, the threshold for the second stage of under-frequency load-shedding. Within the next two seconds another 19% of Ontario demand (4,800 MW) automatically disconnected by under-frequency load-shedding. At 16:11:10 EDT, these same three lines tripped a second time west of Niagara, and New York and most of Ontario separated for a final time. Following this separation, the frequency in Ontario declined to 56 Hz by 16:11:57 EDT. With Ontario still supplying 2,500 MW to the Michigan-Ohio load pocket, the remaining ties with Michigan tripped at 16:11:57 EDT. Ontario system frequency declined, leading to a widespread shutdown at 16:11:58 EDT and the loss of 22,500 MW of load in Ontario, including the cities of Toronto, Hamilton, and Ottawa.

7D) Southwest Connecticut Separated from New York City: 16:11:22 EDT

In southwest Connecticut, when the Long Mountain-Plum Tree line (connected to the Pleasant Valley substation in New York) disconnected at 16:11:22 EDT, it left about 500 MW of southwest Connecticut demand supplied only through a 138-kV underwater tie to Long Island. About two seconds later, the two 345-kV circuits connecting southeastern New York to Long Island tripped, isolating Long Island and southwest Connecticut, which remained tied together by the underwater Norwalk Harbor-to-Northport 138-kV cable. The cable tripped about 20 seconds later, causing southwest Connecticut to black out.

Within the western New York island, the 345-kV system remained intact from Niagara east to the Utica area, and from the St. Lawrence/Plattsburgh area south to the Utica area through both the 765-kV and 230-kV circuits. Ontario's Beck and Saunders generation remained connected to New York at Niagara and St. Lawrence, respectively, and this island stabilized with about 50% of the pre-event load remaining. The boundary of this island moved southeastward as a result of the reclosure of Fraser-to-Coopers Corners 345-kV line at 16:11:23 EDT.

As a result of the severe frequency and voltage changes, many large generating units in New York and Ontario tripped off-line. The eastern island of New York, including the heavily populated areas of southeastern New York, New York City, and Long Island, experienced severe frequency and voltage declines. At 16:11:29 EDT, the New Scotland-to-Leeds 345-kV circuits tripped, separating the island into northern and southern sections. The small remaining load in the northern portion of the eastern island (the Albany area) retained

Figure 6.27. Frequency Separation Between Ontario and Western New York
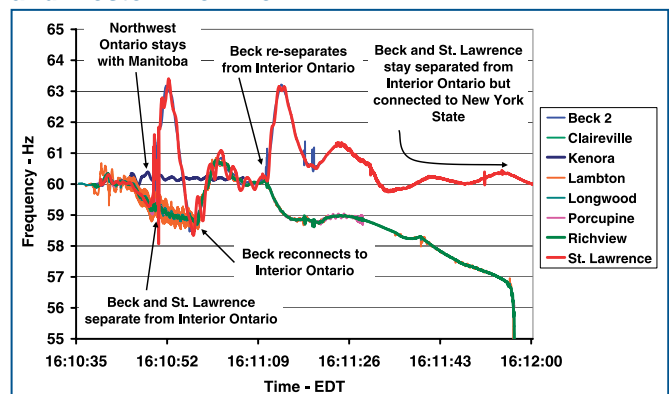
electric service, supplied by local generation until it could be resynchronized with the western New York island.

7E) Remaining Transmission Lines Between Ontario and Eastern Michigan Separated: 16:11:57 EDT

Before the blackout, New England, New York, Ontario, eastern Michigan, and northern Ohio were scheduled net importers of power. When the western and southern lines serving Cleveland, Toledo, and Detroit collapsed, most of the load remained on those systems, but some generation had tripped. This exacerbated the generation/load imbalance in areas that were already importing power. The power to serve this load came through the only major path available, via Ontario (IMO). After most of IMO was separated from New York and generation to the north and east, much of the Ontario load and generation was lost; it took only moments for the transmission paths west from Ontario to Michigan to fail.

When the cascade was over at about 16:12 EDT, much of the disturbed area was completely blacked out, but there were isolated pockets that still had service because load and generation had reached equilibrium. Ontario's large Beck and Saunders hydro stations, along with some Ontario load, the New York Power Authority's (NYPA) Niagara and St. Lawrence hydro stations, and NYPA's 765-kV AC interconnection to the Québec HVDC tie, remained connected to the western New York system, supporting demand in upstate New York.

Electrical islanding. Once the northeast became isolated, it lost more and more generation relative to load as more and more power plants tripped off-line to protect themselves from the growing disturbance. The severe swings in frequency and voltage in the area caused numerous lines to trip, so the isolated area broke further into smaller islands. The load/generation mismatch also affected voltages and frequency within these smaller areas, causing further generator trips and automatic under-frequency load-shedding, leading to blackout in most of these areas.

Figure 6.28 shows frequency data collected by the distribution-level monitors of Softswitching Technologies, Inc. (a commercial power quality company serving industrial customers) for the area affected by the blackout. The data reveal at least five separate electrical islands in the Northeast as the cascade progressed. The two paths of red diamonds on the frequency scale reflect the Albany area island (upper path) versus the New York City island, which declined and blacked out much earlier.

Cascading Sequence Essentially Complete: 16:13 EDT

Most of the Northeast (the area shown in gray in Figure 6.29) was now blacked out. Some isolated areas of generation and load remained on-line for several minutes. Some of those areas in which a close generation-demand balance could be maintained remained operational.

One relatively large island remained in operation serving about 5,700 MW of demand, mostly in western New York, anchored by the Niagara and St. Lawrence hydro plants. This island formed the basis for restoration in both New York and Ontario.

The entire cascade sequence is depicted graphically in Figure 6.30.

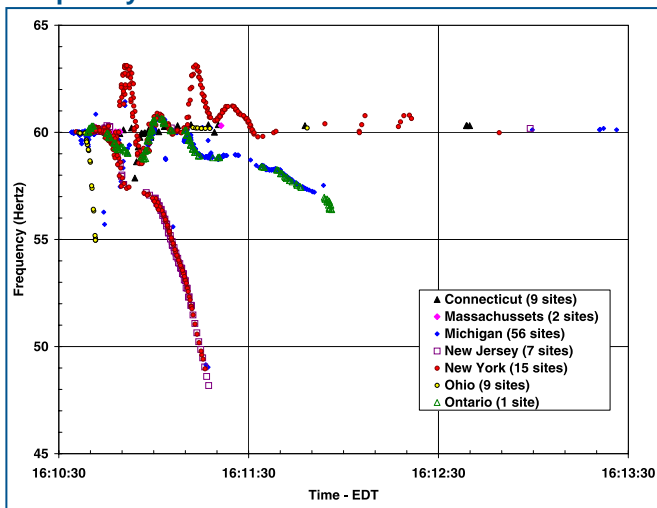**Figure 6.28. Electric Islands Reflected in Frequency Plot**

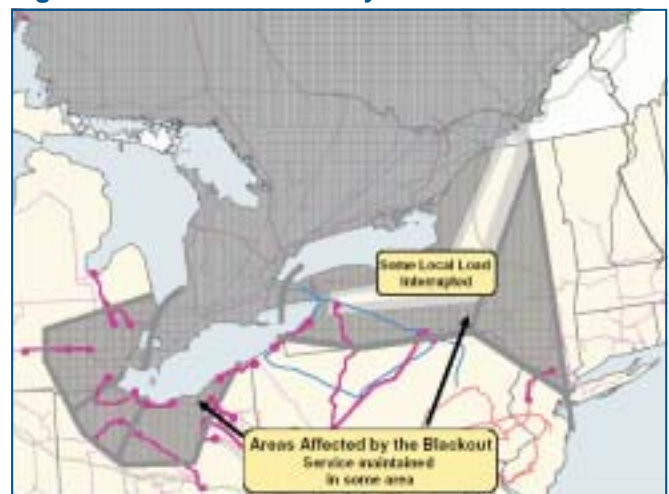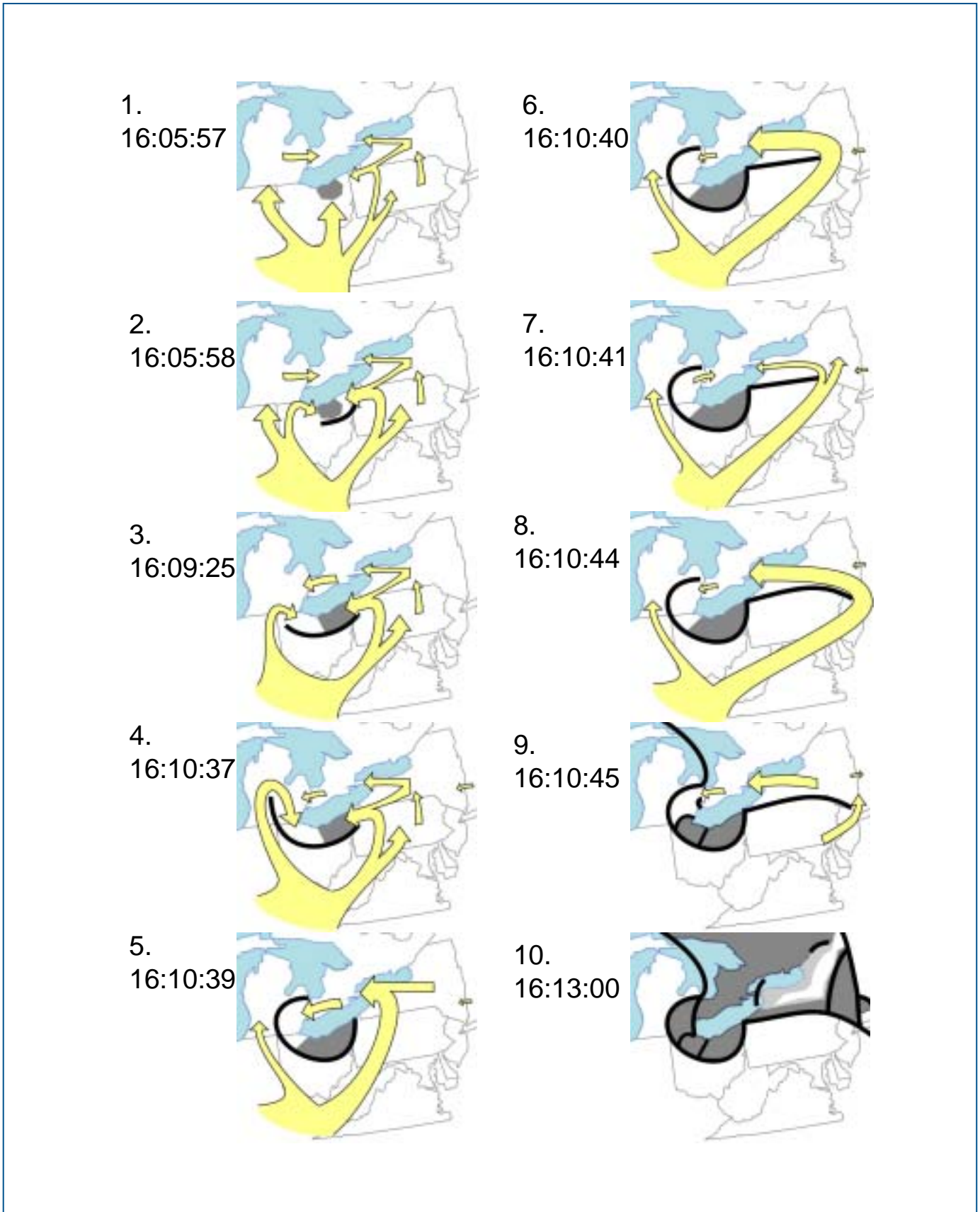**Figure 6.29. Area Affected by the Blackout**

Figure 6.30. Cascade Sequence

Legend: Yellow arrows represent the overall pattern of electricity flows. Black lines represent approximate points of separation between areas within the Eastern Interconnect. Gray shading represents areas affected by the blackout.

Endnotes

[1] New York Independent System Operator, *Interim Report on the August 14, 2003 Blackout*, January 8, 2004, p. 14.

[2] *Ibid.*, p. 14.

[3] These zone 2s are set on the 345-kV lines into the Argenta substation. The lines are owned by Michigan Electric Transmission Company and maintained by Consumers Power. Since the blackout occurred, Consumers Power has proactively changed the relay setting from 88 Ohms to 55 Ohms to reduce the reach of the relay. Source: Charles Rogers, Consumers Power.

[4] The province of Québec, although considered a part of the Eastern Interconnection, is connected to the rest of the Eastern Interconnection only by DC ties. In this instance, the DC ties acted as buffers between portions of the Eastern Interconnection; transient disturbances propagate through them less readily. Therefore, the electricity system in Québec was not affected by the outage, except for a small portion of the province's load that is directly connected to Ontario by AC transmission lines. (Although DC ties can act as a buffer between systems, the tradeoff is that they do not allow instantaneous generation support following the unanticipated loss of a generating unit.)

[5] New York Independent System Operator, *Interim Report on the August 14, 2003 Blackout*, January 8, 2004, p. 20.

[6] *Ibid.*, p. 20.

[7] After New England's separation from the Eastern Interconnection occurred, the next several minutes were critical to stabilizing the ISO-NE system. Voltages in New England recovered and over-shot to high due to the combination of load loss, capacitors still in service, lower reactive losses on the transmission system, and loss of generation to regulate system voltage. Over-voltage protective relays operated to trip both transmission and distribution capacitors. Operators in New England brought all fast-start generation on-line by 16:16 EDT. Much of the customer process load was automatically restored. This caused voltages to drop again, putting portions of New England at risk of voltage collapse. Operators manually dropped 80 MW of load in southwest Connecticut by 16:39 EDT, another 325 MW in Connecticut and 100 MW in western Massachusetts by 16:40 EDT. These measures helped to stabilize their island following their separation from the rest of the Eastern Interconnection.

[8] New York Independent System Operator, *Interim Report on the August 14, 2003 Blackout*, January 8, 2004, p. 23.