

3. Status of the Northeastern Power Grid Before the Blackout Sequence Began

Summary

This chapter reviews the state of the northeast portion of the Eastern Interconnection during the days prior to August 14, 2003 and up to 15:05 EDT on August 14 to determine whether conditions at that time were in some way unusual and might have contributed to the initiation of the blackout. The Task Force’s investigators found that at 15:05 EDT, immediately before the tripping (automatic shutdown) of FirstEnergy’s (FE) Harding-Chamberlin 345-kV transmission line, the system was able to be operated reliably following the occurrence of any of more than 800 contingencies, including the loss of the Harding-Chamberlin line. At that point the system was being operated near (but still within) prescribed limits and in compliance with NERC’s operating policies.

Determining that the system was in a reliable operational state at that time 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 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:

- ◆ High power flows to Canada
- ◆ System frequency variations
- ◆ Low voltages earlier in the day or on prior days
- ◆ Low reactive power output from IPPs
- ◆ Unavailability of individual generators or transmission lines.

It is important to emphasize that establishing whether conditions were normal or unusual prior to and on August 14 has no direct bearing on the responsibilities and actions expected of the organizations and operators who are 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. Sound reliability management is designed to ensure that safe operation of the system will continue 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.

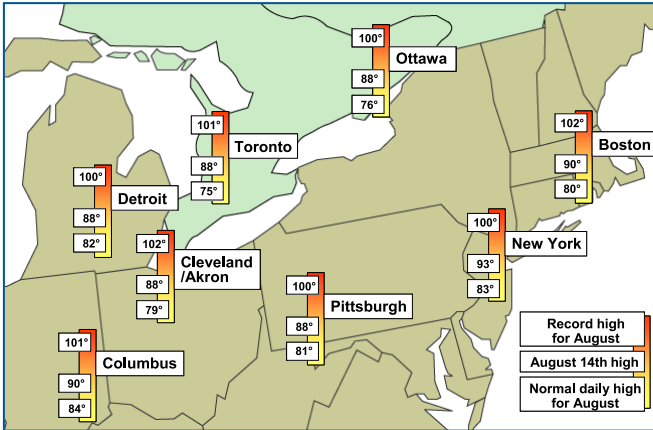
In terms of day-ahead planning, this means evaluating and if necessary adjusting the planned generation pattern (scheduled electricity transactions) to change the transmission flows, so that if a key facility were lost, the operators would still be able to readjust the remaining system and operate within safe limits. In terms of real-time operations, this means that the system should be operated at all times so as to be able to withstand the loss of any single facility and still remain within the system’s thermal, voltage, and stability limits. If a facility is lost unexpectedly, the system operators must determine whether to make operational changes to ensure that the remaining system is able to withstand the loss of yet another key element and still remain able to operate within safe limits. This includes adjusting generator outputs, curtailing electricity transactions, 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.

Electric Demands on August 14

Temperatures on August 14 were above normal throughout the northeast region of the United

States and in eastern Canada. As a result, electricity demands were high due to high air conditioning loads typical of warm days in August, though not unusually so. System operators had successfully managed higher demands both earlier in the summer and in previous years. Recorded peak electric demands throughout the region on August 14 were below peak demands recorded earlier in the summer of 2003 (Figure 3.1).

Figure 3.1. August 2003 Temperatures in the U.S. Northeast and Eastern Canada



Power Flow Patterns

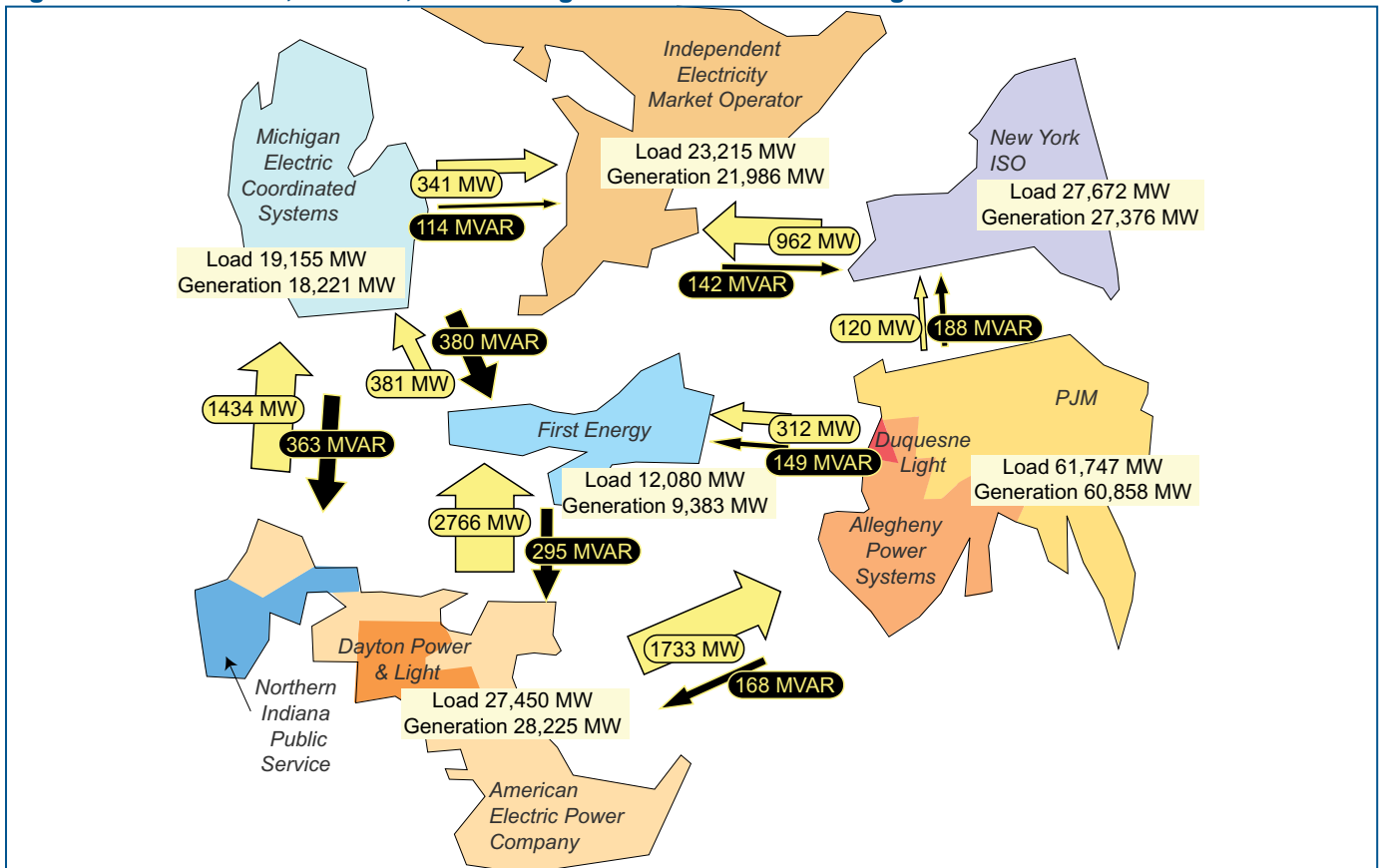
On August 14, the flow of power through the ECAR region was heavy as a result of large transfers of power from the south (Tennessee, Kentucky, Missouri, etc.) and west (Wisconsin, Minnesota, Illinois, etc.) to the north (Ohio, Michigan, and Ontario) and east (New York). The destinations for much of the power were northern Ohio, Michigan, PJM, and Ontario (Figure 3.2).

While heavy, these transfers were not beyond previous levels or in directions not seen before (Figure 3.3). The level of imports into Ontario on August 14 was high but not unusual, and well within IMO's import capability. Ontario's IMO is a frequent importer of power, depending on the availability and price of generation within Ontario. IMO had imported similar and higher amounts of power several times during the summers of 2002 and 2003.

System Frequency

Although system frequency on the Eastern Interconnection was somewhat more variable on

Figure 3.2. Generation, Demand, and Interregional Power Flows on August 14 at 15:05 EDT

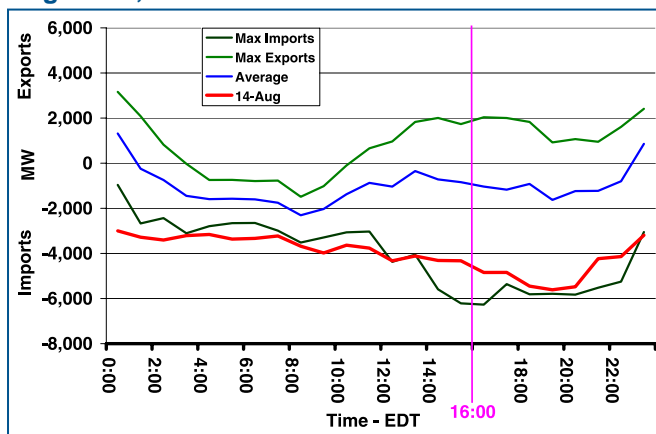


August 14 prior to 15:05 EDT compared with recent history, it was well within the bounds of safe operating practices as outlined in NERC operating policies. As a result, system frequency variation was not a cause of the initiation of the blackout. But once the cascade was initiated, the large frequency swings that were induced became

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.

Figure 3.3. Northeast Central Area Scheduled Imports and Exports: Summer 2003 Compared to August 14, 2003



Note: Area covered includes ECAR, PJM, Ontario, and New York, without imports from the Maritime Provinces, ISO-New England, or Hydro-Quebec.

Table 3.1. Generators Not Available on August 14

Generator	Rating	Reason
Davis-Besse Nuclear Unit	750 MW	Prolonged NRC-ordered outage beginning on 3/22/02
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

a principal means by which the blackout spread across a wide area (Figure 3.4).

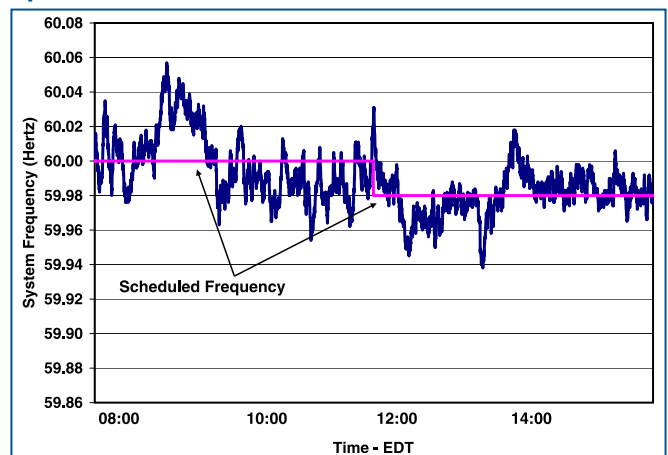
Assuming stable conditions, the system frequency is the same across an interconnected grid at any particular moment. System frequency will vary from moment to moment, however, depending on the second-to-second balance between aggregate generation and aggregate demand across the interconnection. System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

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, was no exception (Table 3.1).

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 3.4. Frequency on August 14, 2003, up to 15:31 EDT



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

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

Voltages

During the days before August 14 and throughout the morning and mid-day on August 14, voltages were depressed in a variety of locations in northern Ohio because of high air conditioning demand and other loads, and power transfers into and across the region. (Unlike frequency, which is constant across the interconnection, voltage varies by location, and operators monitor voltages continuously at key locations across their systems.) However, actual measured voltage levels at key points on FE's transmission system on the morning of August 14 and up to 15:05 EDT were within the range previously specified by FE as acceptable. Note, however, that many control areas in the Eastern Interconnection have set their acceptable voltage bands at levels higher than that used

by FE. For example, AEP's minimum acceptable voltage level is 95% of a line's nominal rating, as compared to FE's 92%.¹

Voltage management is especially challenging on hot summer days because of high air conditioning requirements, other electricity demand, and high transfers of power for economic reasons, all of which increase the need for reactive power. Operators address these challenges through long-term planning, day-ahead planning, and real-time adjustments to operating equipment. On August 14, for example, PJM implemented routine voltage management procedures developed for heavy load conditions. FE also began preparations early in the afternoon of August 14, requesting capacitors to be restored to service² and additional voltage support from generators.³ Such actions were typical of many system operators that day as well as on other days with high electric demand. As the day progressed, operators across the region took additional actions, such as increasing plants' reactive power output, plant redispatch, transformer tap changes, and increased use of capacitors to respond to changing voltage conditions.

The power flow data for northern Ohio on August 14 just before the Harding-Chamberlin line tripped at 15:05 EDT (Figure 3.2) show that FE's load was approximately 12,080 MW. FE was importing about 2,575 MW, 21% of its total system needs, and generating the remainder. With this high level of imports and high air conditioning loads in the

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.

metropolitan areas around the southern end of Lake Erie, FE's system reactive power needs rose further. Investigation team modeling indicates that at 15:00 EDT, with Eastlake 5 out of service, FE was a net importer of about 132 MVar. A significant amount of power also was flowing through northern Ohio on its way to Michigan and Ontario (Figure 3.2). The net effect of this flow pattern and load composition was to depress voltages in northern Ohio.

Unanticipated Outages of Transmission and Generation on August 14

Three significant unplanned outages occurred in the Ohio area on August 14 prior to 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 Dayton Power and Light (DPL) line, the Stuart-Atlanta 345-kV line in southern Ohio, tripped.

- ◆ 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 load

relief (TLR) procedures to control flows on the transmission system in south-central Indiana. System modeling by the investigation team (see details below, page 20) showed that the loss of these lines was *not* electrically related to subsequent events in northern Ohio that led to the blackout.

- ◆ The DPL Stuart-Atlanta 345-kV line, linking DPL to AEP 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 during the entire blackout. As explained below, system modeling by the investigation team has shown that this outage was not a cause of 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 that 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, page 27).
- ◆ Eastlake Unit 5 is a 597-MW generating unit located just west of Cleveland near Lake Erie. It is a major source of reactive power support for the Cleveland area. It tripped at 13:31. The cause of the trip was that as the Eastlake 5 operator sought to increase the unit's reactive power

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.

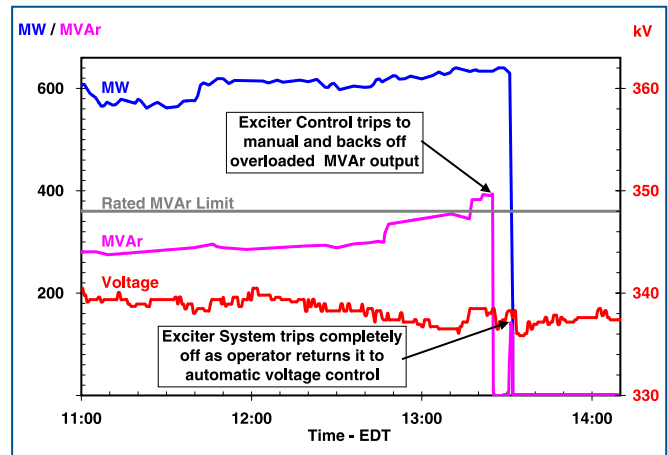
output (Figure 3.5), the unit's protection system detected a failure and tripped the unit off-line. The loss of the Eastlake 5 unit did not put the grid into an unreliable state—i.e., it was still able to withstand safely another contingency. However, the loss of the unit required FE to import additional power to make up for the loss of the unit's output (540 MW), made voltage management in northern Ohio more challenging, and gave FE operators less flexibility in operating their system (see details below, page 27).

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 evolution of the August 14 blackout, the investigative 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 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 study far exceeds that normally considered by individual control areas and reliability coordinators. It consists of a detailed representation of more than 43,000 buses (points at which lines, transformers, and/or generators converge), 57,600 transmission lines, and all major generating stations across the northern U.S. and eastern Canada. The team then revised the summer power flow case to match recorded generation, demand, and power interchange levels among control areas at 15:05 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 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

Figure 3.5. MW and MVar Output from Eastlake Unit 5 on August 14



Harding-Chamberlin 345-kV line. That is, according to these simulations, the system at 15:05 EDT was able to be operated safely following the occurrence of any of the tested contingencies. From an electrical standpoint, therefore, the Eastern Interconnection was then 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 on several lines for two of the contingencies studied. In other words, it would no longer be operating in compliance with NERC operating policies.

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 high power flows to Canada, unusual system frequencies, low voltages earlier in the day or on prior days, and the unavailability of individual generators or transmission lines, either individually or in combination with one another, as direct, principal or sole causes of the blackout.

Endnotes

¹DOE/NERC fact-finding meeting, September 2003, statement by Mr. Steve Morgan (FE), PR0890803, lines 5-23.

²Transmission operator at FE requested the restoration of the Avon Substation capacitor bank #2. Example at Channel 3, 13:33:40.

³From 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.