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Human and Organizational Factors that Contributed to the US-Canadian August 2003 Electricity Grid Blackout

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Background

The US-Canadian electricity grid is a network of providers and users that operate almost completely independently of one another. In August of 2003, First Energy's (FE) Harding-Chamberlain transmission line near Akron, Ohio went offline starting a series of cascading failures that eventually led to 8 US states and 1 Canadian province totaling nearly 50 million people without power. The failure of transmission lines are common occurrences relating to the inability to exactly predict the electricity demand at any time (as will be discussed later in this document). The inability to properly monitor and react across multiple organizations to the downed line was the true failure that led to the blackout. This outage not only left homes and businesses without power but paralyzed critical public services such as transportation networks and hospitals. The estimated cost of the outage is between 4 and 6 billion US dollars¹. The grid operates according to the physics of the flow of electrons: electricity is used the instance it is created, electricity travels through the path of least resistance, and electricity cannot be stored in large quantities effectively or economically. The complications of providing this form of energy are difficult enough, let alone coordinating the 3,500 organizations^{2,3,4} that are responsible for managing the network's reliability. The North American Electric Reliability Council⁵ (NERC) is a group composed of public and private organizations that all have vested interests in the electricity grid. These members range from power plant owners to utility owners to independent power producers to citizens. NERC's main function is to ensure the coordination of acceptable standards and practices for all of these parties to maintain the reliability of the network. NERC policies are supposed to provide the foundation for all electric regions to communicate and respond to each other. They also set the guidelines for how equipment should be operated and monitored within organizations and also between organizations.

Description of the Failure

During the summer of 2004, an increase in the daily temperature high from 78°F (26°C) on August 11 to 87°F (31°C) on August 14 created an increased demand for electricity. This increased demand was not unexpected. Because electricity is used the instance it is created, power producers create yearly, monthly, weekly, daily, and hourly models to estimate demand. Demand is predictable in that sense that more electricity is used in the summer than the winter and during the day than at night. Historical data and trends in energy use aid in creating these models but results are never exact. Active monitoring of systems (by both computers and people) 24 hours per day allow for the additional fine-tuning of output to match use. Electricity is transmitted at 60Hz (60 cycles per second) but demand can cause fluctuations in this frequency in equipment (such as transmission lines). If demand is greater than supply then frequency decreases while if demand is less than supply frequency increases. Generators are constantly adapting to these changes matching voltage supply to demand. NERC has set guidelines for acceptable use of equipment due to the hazards of electricity generation and transport. If generators breach a threshold for their production capacity then they are taken offline. Similarly, transmission lines are tripped due to the dangers of sagging closer to other objects from thermal expansion when frequencies increase beyond a certain range. On August 14, the 345-kV Harding-Chamberlain line was tripped leading to increased demand and further tripping of three other 345-kV lines and several 138-kV lines in the region. An inability to recognize and properly react to the downed lines led to the blackout. The handling of cascading failures in the electricity network is known as load balancing and is controlled through the policies that NERC has mandated to all parties involved in the grid. The automatic shut-off of the transmission lines originated the cascading failure but is not the cause. Instead, the inability of several organizations involved with monitoring, operating,

and reacting to the situation according to NERC policy was the crux of the blackout. Furthermore, NERC's inability to enforce reliability and safety standards as well as monitor its mandates is also at fault⁶.

The first cause of the failure was FE's inability to accurately predict electricity demand. The tripped transmission lines could have been avoided by FE stepping up output from other stations. Instead, FE found themselves unprepared when demand increased past their predictions and could not accommodate the supply. Furthermore, the East Central Area Reliability Coordination Agreement (ECAR), the NERC monitoring regional council responsible for FE's area, did not conduct appropriate review or analysis of FE's operational capacity and operating needs. Secondly, not only was FE unprepared to handle increased demand, they did not have an effective contingency analysis that would allow them to create an appropriate vegetation management program (to properly enforce load-balancing). FE's monitoring tools were also below NERC specifications. This prevented operators from properly addressing the deteriorating state of the system after their primary alarms and notifications failed. Furthermore, FE's control center staff lacked proper internal communication procedures leading to an inability to respond to the problem. The control center staff had not been receiving automated messages from downed transmission lines because of faulty repairs. Although a technician reported the problem prior to the blackout on August 14, his communication was not appropriately addressed. Thirdly, as a result of the first two causes, FE failed to appropriately respond to the three downed 345-kV and one downed 138-kV lines. Fourth, the reliability coordinator Midwest Independent System Operator (MISO), the organization responsible for enforcing reliability practices between the providers in its region (including FE), lacked real time data about the failures and was therefore unable to provide support to FE or earlier diagnostic assistance. Lastly, NERC is an organization composed of parties that all have investments in the power grid. Rules and regulations are voted on but are often not specified to the level of detail to ensure standards in practice. NERC also has very little authority to issue fines or penalties for violations to policies. These factors will be discussed in more detail in later sections.

System Boundary

The North American electricity grid supports all 50 states as well as parts of Canada and Mexico. Although power flows are managed regionally, effects in one region can affect other regions. On August 14, disruptions in Ohio affected several other areas including eight US states and one Canadian province. These areas were directly affected by the Ohio disruptions in that their power flows had to adjust beyond safety conditions to try to reestablish safe conditions in the region. In this analysis, the system boundary (as illustrated in the Figure 1) has been defined as all of Ohio, Michigan, and New York and the portions of Pennsylvania, Vermont, Massachusetts, Connecticut, New Jersey and Ontario that lost power on the day. Although the entire grid (from Baja, Mexico to New England) experienced abnormal flow patterns as a result of the outage, only the area within the system boundary became unreliable.

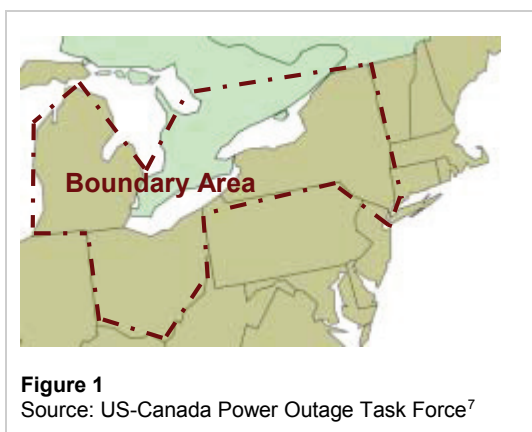


Figure 1
Source: US-Canada Power Outage Task Force⁷

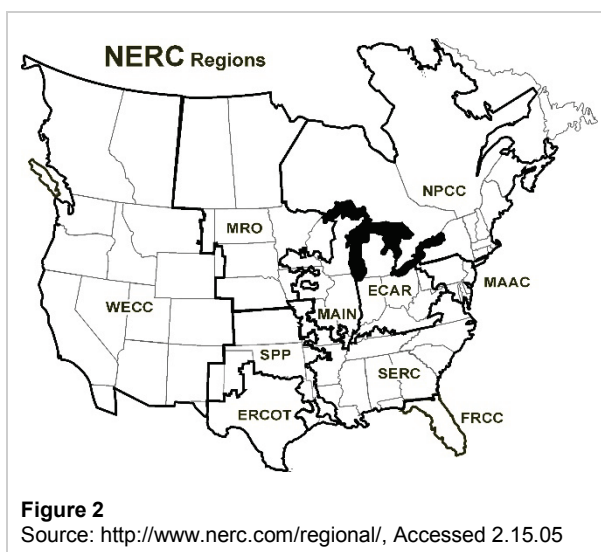
Organizational Structure

To develop a hierarchy of the organizational structure administering the North American power grid, we start with the US Department of Energy (USDOE) at the top. The USDOE disseminates federal policy to the NERC. In response to the 1965 blackout, NERC was created (as a non-governmental and voluntary organization) with the role of coordinating all parties with interests in the system. Since its creation, NERC has relied on cooperation, peer pressure, and mutual self-interest of its member organizations to ensure the reliability of the grid and compliance to policy. NERC's mission⁸ is to:

- Set standards for the reliable operation and planning of the bulk electric system.
- Monitor and assesses compliance with standards for bulk electric system reliability.
- Provide education and training resources to promote bulk electric system reliability.
- Assess, analyzes and reports on bulk electric system adequacy and performance.
- Coordinate with regional reliability councils and other organizations.
- Coordinate the provision of applications (tools), data and services necessary to support the reliable operation and planning of the bulk electric system.
- Certify reliability service organizations and personnel.
- Coordinate critical infrastructure protection of the bulk electric system.
- Enable the reliable operation of the interconnected bulk electric system by facilitating information exchange and coordination among reliability service organizations.

It is important to recognize that NERC is a non-governmental organization that relies on the self-interests of its members to ensure reliability of the system. NERC does not have any power to invoke legislation or distribute fines to promote continuing good practices. The last player at the top of the hierarchy is the Federal Energy Regulatory Commission (FERC). FERC is responsible for regulating the sale of electricity to consumers⁹. FERC policy does not have a direct effect on regional reliability or generation but instead on the interface between utilities and the consumers.

Below NERC, there are 10 regional reliability councils composed of investor-owned utilities, federal power agencies, electric cooperatives, state and provincial utilities, independent power producers, power marketers, and the customers. The 10 regional reliability councils account for almost all electricity supplied in the United States, Canada, and Baja, Mexico. These councils adopt NERC policy and their members fund NERC. During the 2003 blackout, three regional reliability councils were affected: the East Central Area Reliability Coordination Agreement (ECAR), the Mid-Atlantic Area Council (MAAC), and the Northeast Power Coordinating Council (NPCC).



Within each of the 10 regional reliability councils there exist sub-regions known as Control Areas. These sub-regions are the final reliability organizations within the hierarchy. Sub-regions (also known as independent system operators (ISO) and regional transmission organizations (RTO)) are responsible for balancing electricity generation and loads in real time controlling operations

of the grid while meeting demand. The control areas control electricity directly at the plants while coordinating with each other to ensure there are no compromises of their interchanges. There are 140 control areas¹⁰ in North America (on average 14 per regional council) which are staffed 365 days a year, 24 hours per day. In the past, control areas were defined by the boundaries between utilities in a region. They were managed by these vertically integrated utilities providing an additional level of coordination since all functions were kept within a single organization. There recently has been some restructuring of control areas through consolidation and handing over of responsibilities to independent groups. These groups are sometimes not involved in the generation of electricity themselves however they must manage the other organization's output. During the 2003 blackout, five independent system operators were involved in the failure: Midwest Independent System Operator (MISO), PJM Interconnection (PJM), New York Independent System Operator (NYISO), New England Independent System Operator (ISO-NE), and the Ontario Independent Market Operator (IMO).

The next section of this report will develop the three regions and their key players. Also, all parties involved in the blackout will be identified including their individual roles to policy and organizational structure that contributed to the failure.

Key Parties Involved

NERC operating policy 2.A for transmission operators states that “all control areas shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency¹².” During the 2003 blackout, there were several reliability organizations that failed to meet this policy leading to the cascading failure in an entire region.

First, two independent system operators, the Midwest Independent System Operator (MISO) and PJM Interconnection (PJM) failed to appropriately address system transmission problems and communicate actions to the control areas in their management. MISO is responsible for a region nearly 1 million square miles stretching from Canada to Kentucky in the North-South and Montana to Western Pennsylvania in the East-West. There are 37 control areas under MISO's jurisdiction however FirstEnergy (discussed further in this section) was their critical control area during the failure. PJM was established in 1935 as a regional power pool. PJM has recently expanded its control areas from the East coast to include control areas and transmission operators in the Midwest. Depending on the region (East or West), PJM performs its duties differently. In the East, PJM manages ten utilities in the role of control area coordinator and reliability coordinator. In the West, PJM is not in charge of any control areas but serves as a reliability coordinator to five control areas (including American Electric Power discussed further in this section). It is important to recognize that reliability coordination is more difficult in the Midwest than the Northeast. This is because in the Northeast the independent system operators are also usually the control area manager. This is not true in the Midwest. This

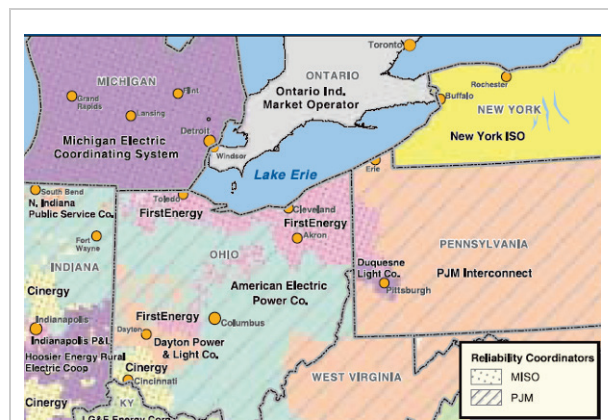


Figure 3 – Reliability Coordinators and Control Areas near Ohio

Source: US-Canada Power Outage Task Force¹¹

creates what are called interfaces between independent system operators where reliability between organizations must also be managed (as will be discussed).

Continuing down the hierarchy, the two key control areas involved in the blackout belonged to FirstEnergy (FE) and American Electric Power (AEP). FE is composed of seven electricity utilities mostly in central to north Ohio. At the time of failure, four of the seven utilities (Ohio Edison, Toledo Edison, The Illuminating Company, and Penn Power) were under the jurisdiction of MISO while the other three were under another jurisdiction. After the blackout, the seven were consolidated to a single independent system operator. Under PJM's jurisdiction was AEP operating just south of FE in Ohio. AEP acts as both a control area and a transmission operator.

Timeline of Events

In response to the 2003 blackout, a committee was formed with members from both the United States and Canada to determine causes of the failure, conditions for the failure, and recommendations to avoid future failures. This committee, the US/Canada Power Outage Task Force, published a timeline¹³ of the major events that contributed and ultimately caused the cascading failure. The report was published just two months (September 13) after the outage. The quickness of this analysis suggests that the major contributors to the blackout were not the mechanical elements of the system but more the Human and Organizational (HOF) factors that created the conditions for the elements to fail. This report will follow the US/Canada Power Outage Task Force's timeline of hardware failures.

Before illustrating the timeline events, it is important to identify the conditions for transmission line tripping and automatic shutoff of generators. All transmission lines can carry an upper limit voltage (typically 345kv, 203kv, or 138kv). In order to maintain this capacity voltage, a portion of the total power, called "reactive power" is used. Generating facilities supply sufficient reactive power into their transmission lines to maintain capacity. Also, capacitors (somewhat like batteries) are used throughout the grid to balance the load. Reactive power, however, is not just produced but also consumed. Electromagnetic devices (such as motors) draw reactive power as do heavily loaded transmission lines. As transmission lines become more and more loaded, they require more and more reactive power, and are more likely to trip when the demand is not met. It is not effective to transmit electricity long distances because reactive power meets considerable resistance in the transmission lines. As a result, electricity generation sources are constructed near areas of demand. When a transmission line is tripped, the reactive power is transferred to other lines. If reactive power supply is insufficient then the transmission lines will be unable to maintain their voltage and the line will trip. This physical property is the primary element of the cascading hardware failures in the 2003 blackout.

The conditions leading to the blackout occurred between noon and 4:13pm. All times are given in Eastern Standard Time. The cascading failure occurred between 4:10pm and 4:13pm as power regions disconnected themselves from other problem regions.

Phase 1

Timeframe: 12:05:44pm to 1:31:34pm

Location: Central Ohio, Northeast Ohio, Detroit

The hot day led to an increase in electricity consumption beyond the estimate created by Midwest Independent System Operator (MISO). During this time, three generating facilities went offline as electricity consumption exceeded demand. The geographic proximity of these three plants created a condition on the regional grid (primarily Ohio and Eastern Michigan) where other transmission lines became more heavily relied upon to deliver electricity. Figure 4 illustrates the location of the three generating facilities and the major transmission lines for the region (shown in green).

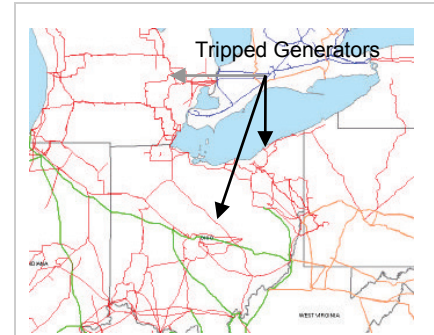


Figure 4 – Timeline Phase 1

Source: US-Canada Power Outage Task Force¹⁴

Phase 2

Timeframe: 2:02pm

Location: Southwest Ohio

Although one of the three generating facilities had come back online, two were still out and the transmission lines in the region were maintaining excess load to meet demand. During this 2 hour period (12:05pm to 2:02pm), the regional transmission lines were maintaining capacity until a brush fire affected the Stuart-Atlanta 345kv major line in Southwest Ohio. Fires have the ability to ionize the air around them. When this occurs beneath transmission lines then short circuits can occur. This is what happened at 2:02pm.

Phase 3

Timeframe: 3:05:41pm to 4:10:27pm

Location: Central to Northeast Ohio

With two generating facilities offline and a major 345kv transmission line offline, there was a major strain on the grid to deliver electricity to Northern Ohio and Eastern Michigan. First, two 345kv lines tripped near the two offline generating facilities in Northeast Ohio. At this point, the only paths for electricity to get to Northeast Ohio was from the West. What resulted was two transmission lines in central Ohio trying going offline while trying to maintain the excess capacity. Figure 5 illustrates this series of events. The black line represents the offline transmission lines in Northeast Ohio resulting from the downed generating facilities. The blue lines represent the two downed transmission lines trying to deliver electricity to Northeast Ohio after the black line initiated.

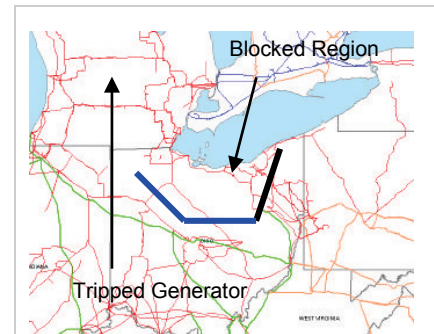


Figure 5 – Timeline Phase 3

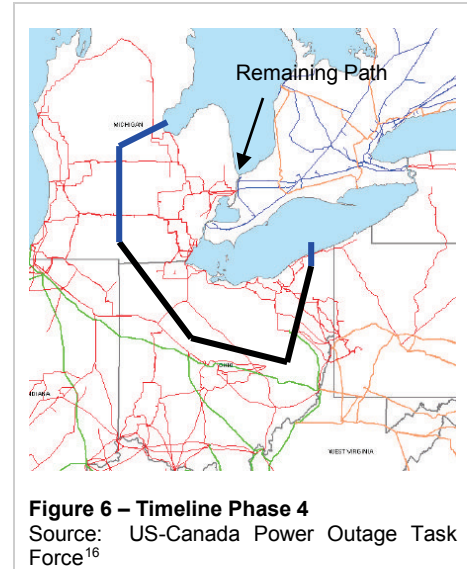
Source: US-Canada Power Outage Task Force¹⁵

Phase 4

Timeframe: 4:10:00pm to 4:10:38pm

Location: Central to Northeast Ohio

The downed region left only three 345kv lines into Eastern Michigan from the continental United States. Eastern Michigan is also connected to Ontario through a single remaining path. During these 38 seconds, Indiana began to experience heavy power flows trying to serve Northern Ohio and Eastern Michigan. At this time, the cascading failure begins. The remaining three 345kv lines connecting Eastern Michigan trip creating an almost isolated pocket containing Eastern Michigan and Northern Ohio. This pocket was serviced by 22 generating facilities that all go offline during this short period causing the region to experience a blackout. Although the blackout region is isolated from the continental United States, there is still one path that is part of the grid that can provide electricity to the depressed region.



Phase 5

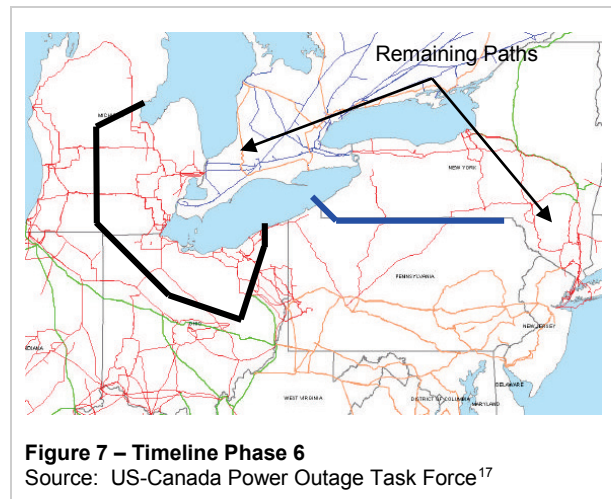
Given the behavior described in Phases 1 through 4, the expectation might be for the remaining path connecting Ontario to Eastern Michigan to shed its voltage due to excessive reactionary voltage demand and go offline. This does occur but not before a reversal shift in the transmission behavior of the system. The electricity that had been transmitted from the East (Pennsylvania and New York) into Ohio now experiences no available paths to deliver electricity to the outage region. As a result, transmission flips and begins transmitting in the opposite direction to get electricity through the Ontario to Eastern Michigan remaining path (see Figure 6).

Phase 6

Timeframe: 4:10:40pm to 4:10:44pm

Location: Northern Pennsylvania

As the transmission of electricity reversed attempting to balance the power flow into the outage region, all four lines connecting Pennsylvania to New York disconnect. The lines begin disconnecting only 2 seconds after the outage reason becomes isolated (Phase 4). It takes only four seconds for all four transmission lines to go offline. After the Pennsylvania lines go offline, Northern Ohio and Eastern Michigan still remain connected to the grid through the Ontario line. This connection has just had its source constrained from the US to the New Jersey to New York connection.



Phase 7

Timeframe: 4:10:42pm to 4:10:45pm

Location: Northern Pennsylvania

The Eastern Michigan to Ontario connection has several transmission lines in two locations. The Southern most transmission line disconnects leaving one connection between the two regions. The Branchburg-Ramapo line connecting New Jersey to New York also disconnects. The electricity grid is a shared resource between Canada, the United States, and a small part of Mexico. Eastern Canada was still connected to Western Canada through a line just North of Lake Superior (not shown on the map). This line disconnects during this phase as well.

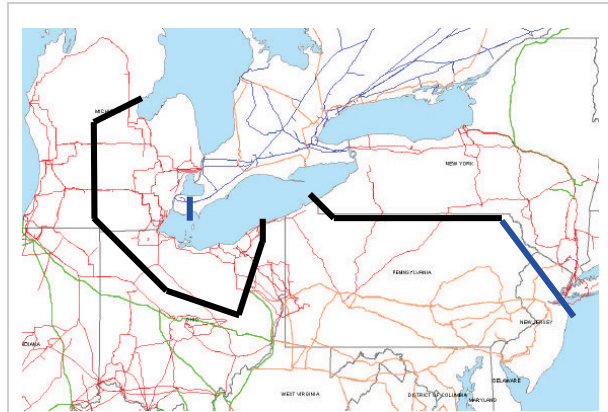


Figure 8 – Timeline Phase 7

Source: US-Canada Power Outage Task Force¹⁸

Phase 8

Timeframe: 4:10:46pm to 4:10:55pm

Location: Eastern New York

Phases 5 through 7 have illustrated an eastward shift of strain on the electricity grid. As transmission lines go offline, generating facilities within isolated regions are pushed to meet demand with fewer and fewer resources. During the 9 seconds of Phase 8, New York splits from New England as several lines disconnect. New England has enough generating capacity and is matched closely enough with the demand that it remains operational during the failure. New York and Ontario are now strained and generating facilities begin to go offline.

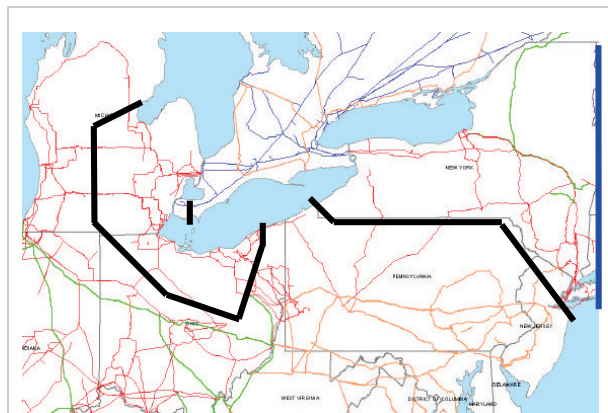


Figure 9 – Timeline Phase 8

Source: US-Canada Power Outage Task Force¹⁹

Phase 9

Timeframe: 4:10:50pm to 4:11:57pm

Location: Ontario Borders

Ontario is now the primary supplier to Eastern Michigan, Northern Ohio, and the entire state of New York. Ontario's 22,500MW of generating capacity is disconnected in a single minute as voltage across transmission lines at the borders increases and these lines go offline. The Canadian province is now almost completely self sufficient to meet its own demand requirements. Eastern New York blacked out completely while Western New York is able to service about 50% of demand. There is 24,000MW of demand in Ontario and not enough generating capacity.

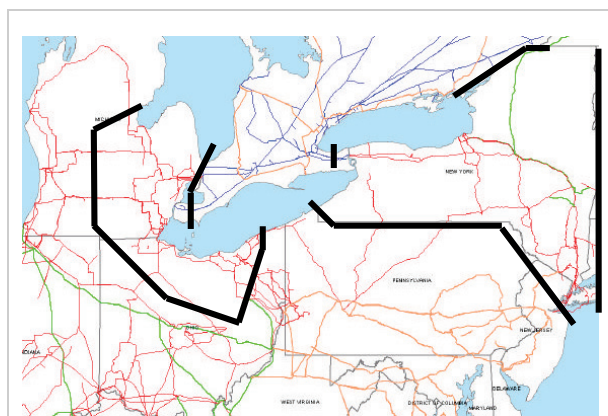


Figure 10 – Timeline Phase 9

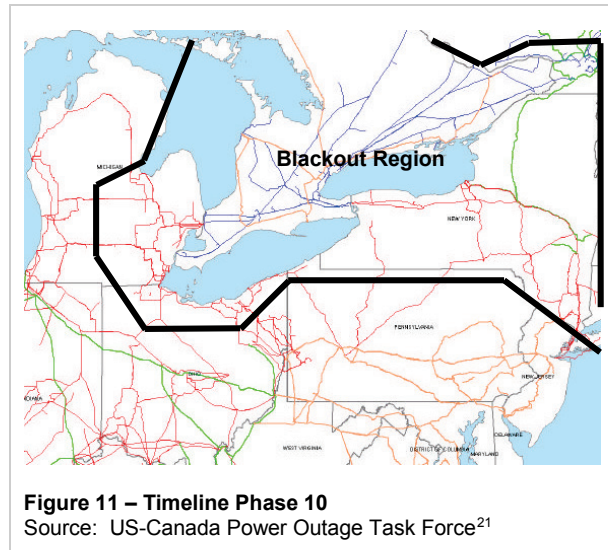
Source: US-Canada Power Outage Task Force²⁰

Phase 10

Timeframe: 4:13pm

Location: Blackout Region

Figure 11 illustrates the entire blackout region as of 4:13pm. Although mechanical causes of the blackout were traced back to 12:05pm (Phase 1), the cascading characteristics began at 4:10pm (Phase 4). Isolated regions where load met demand were able to stay online. The generating facilities near Niagara Falls were the largest of these serving 5700MW of demand. This pocket of success served as the restoration origin for the entire region when the system was brought back online. The blackout region contained nearly 50 million customers in eight US states and one Canadian province.



Analysis Overview

With the background established, it is necessary to perform an analysis on the events that occurred to understand the behavior of the system and what recommendations should be made to address them. In the following sections, several analyses are performed to understand the behavior of the system. Initiating events that started the series of failure that led to the cascade are first analyzed. Next, the likelihood that the failure events would have occurred are detailed. Violations in operator performance are then analyzed to determine what conditions were created such that desirable quality and reliability could not be achieved. Lastly, a proactive, interactive, and reactive analysis are performed to study the hardware, software, and “fluffyware” (people) that played roles in determining the outcome (cascading failure of the grid in the Northeast) on August 14, 2003.

Initiating Events & Performance Shaping Factors

In 2003, the American National Academy of Engineering declared the North American power grid the greatest technological advancement of the past century²². The academy declared that “widespread electrification gave us power for our cities, factories, farms, and homes—and forever changed our lives... from street lights to supercomputers, electric power makes our lives safer, healthier, and more convenient.” The timeline presented illustrates ten phases of hardware operation that were the final result of the failure. The hardware performed just as it had been instructed to. Transmission lines shut down to prevent hazardous conditions and generating facilities went offline to prevent further hardware failure. If the hardware behaved just as it was supposed to, how did the greatest technological advancement of the past century fail? This question can be answered by looking at the complex human and organizational structure of the system as well as the policies that were implemented across 3500 electric organizations.

Before analyzing the failure of this system in August 2003, it is important to clarify what failure and its complement, reliability, actually mean. The following explanation is from Bea identifying the relationship between quality, reliability, and failure²³. Quality is the “freedom from unanticipated defects in the serviceability, safety, durability, and compatibility of the system.”

Quality Assurance and Quality Control (QA/QC) are the practices of an organization or person to meet the desired level of quality of a system. QA/QC is related to detection and correction of components in a system that are not meeting desired quality levels. Reliability is related to quality. Reliability is the likelihood that a given level of quality will be achieved. The likelihood of unacceptable performance (the inability to meet a desired level of serviceability, safety, durability, and compatibility) is known as the probability of failure. There are two categories that define the elements contributing to a system's inability to meet quality standards: intrinsic and extrinsic. Intrinsic factors are those that are natural or due to inherent randomness. In the electricity grid, a bird landing on a transmission line causing a shortage would be considered an intrinsic factor. Extrinsic factors are those related to compromises of the quality of the system from Human and Organizational Factors (HOF). This section focuses on the HOF factors that contributed to the failure of the electricity grid.

This section presents five human and organizational factors that led to the system failing to meet a desired level of quality. These factors will be presented through the conceptual framework just discussed²⁴. There were many violations of NERC policy that took place across many organizations involved in the grid prior to the blackout. The five factors discussed in this section were the worst violations in that if they had not occurred, the cascading failure would not likely have happened. The violations were presented by the US-Canada Task Force in their final report²⁵ but will be described through the framework discussed.

Factor 1

Description: System Understanding

Parties involved: NERC, FirstEnergy (FE), East Central Area Reliability Coordinator (ECAR)

As presented in the timeline, the cascading failure began in FE's transmission lines in Central Ohio. The failure of three transmission lines quickly escalated to the blackout of Northern Ohio and Eastern Michigan and eventually led the full outage. According to NERC Policy 2, FE was required to manage their reserve capacity. This policy indicates that in a situation such as this, FE should be able to keep their domain operational for at least 30 minutes. This would give time for regional coordinators to react and transfer load to trouble areas. FE had not prepared for this situation and was unable to manage their reserves. This problem does not stop at FE. NERC has audit processes to ensure that FE and other control areas follow this policy to manage their reserves. NERC did not however, have sufficient guidelines for performing these audits. As a result, control areas such as FE's went unchecked. The regional reliability council for FE, ECAR, also did not conduct adequate reviews of FE's capacity. If they had, ECAR would have determined that FE did not have adequate voltage shedding procedures in Central Ohio.

Factor 2

Description: Situational Awareness

Parties involved: FirstEnergy (FE)

When the early phases of the blackout began in Central Ohio, FE did not have the information necessary to make informed decisions for corrective action. In FE's control room, operators were aware of falling voltages but did not trust their data gathering tools and failed to evaluate the severity of the situation. When FE finally realized that their system was in trouble (already too late to stop the cascade), they did not declare an emergency to their reliability coordinator (Midwest Independent System Operator). FE had not prepared its operators to effectively evaluate the system conditions. After the failure, operators were interviewed to discover what problems had occurred preventing diagnosis. The evaluator discovered that the information was available to make a correct diagnosis of the problems but operators had failed to communicate clues to one another. This was attributed to their physical separation, a lack of shared data, poor procedures for briefings during staff shifts, and infrequent training for emergency scenarios.

Factor 3

Description: Tree Trimming

Parties involved: NERC, FirstEnergy (FE)

FE had not pruned trees near the three main lines in Central Ohio where the blackout began. When the two generating facilities in Northeast Ohio went offline, additional voltage was shifted onto these lines. Additional voltages led to temperature increase in the cables affecting the metal composition. As the lines heated up, they began to sag, and all three eventually came into contact with trees and short circuited. FE had performed bi-annual checks of their lines. Inspector logs for the three lines show that at the time of inspection, the lines were in acceptable limits yet growth after inspection had not been discovered. NERC does not have policy for maintaining trees near transmission lines.

Factor 4

Description: Failure to Provide Support

Parties involved: MISO, PJM, FirstEnergy (FE), American Electric Power (AEP)

Independent system operators (MISO and PJM in this situation) are responsible for monitoring several control areas (FE, AEP) and reacting to potential hazardous conditions. Because of the complexity of the grid, independent system operators monitor the network through models which are fed real time data and predict future conditions and policies. Models are selective representations of reality. MISO, responsible for FE's control area, was not monitoring the three downed lines that started the blackout in their model. These lines were not considered in the model as major factors for the region. When they went down, MISO was unable to develop appropriate responses because of this. Also, because their software was not considering these lines, MISO was unable to predict power flows in their emergency management system. FE's system was also not properly evaluating the status of the downed lines. It took MISO 36 minutes to discover what was happening and by this time it was too late to prevent further failures. The nearby AEP control area was getting data on one of the three downed lines but not the other two. AEP asked its reliability coordinator (PJM) to come up with a contingency plan which it did including the other two lines. By the time AEP and PJM realized all three lines were down, they also were unable to prevent further outages.

Factor 5

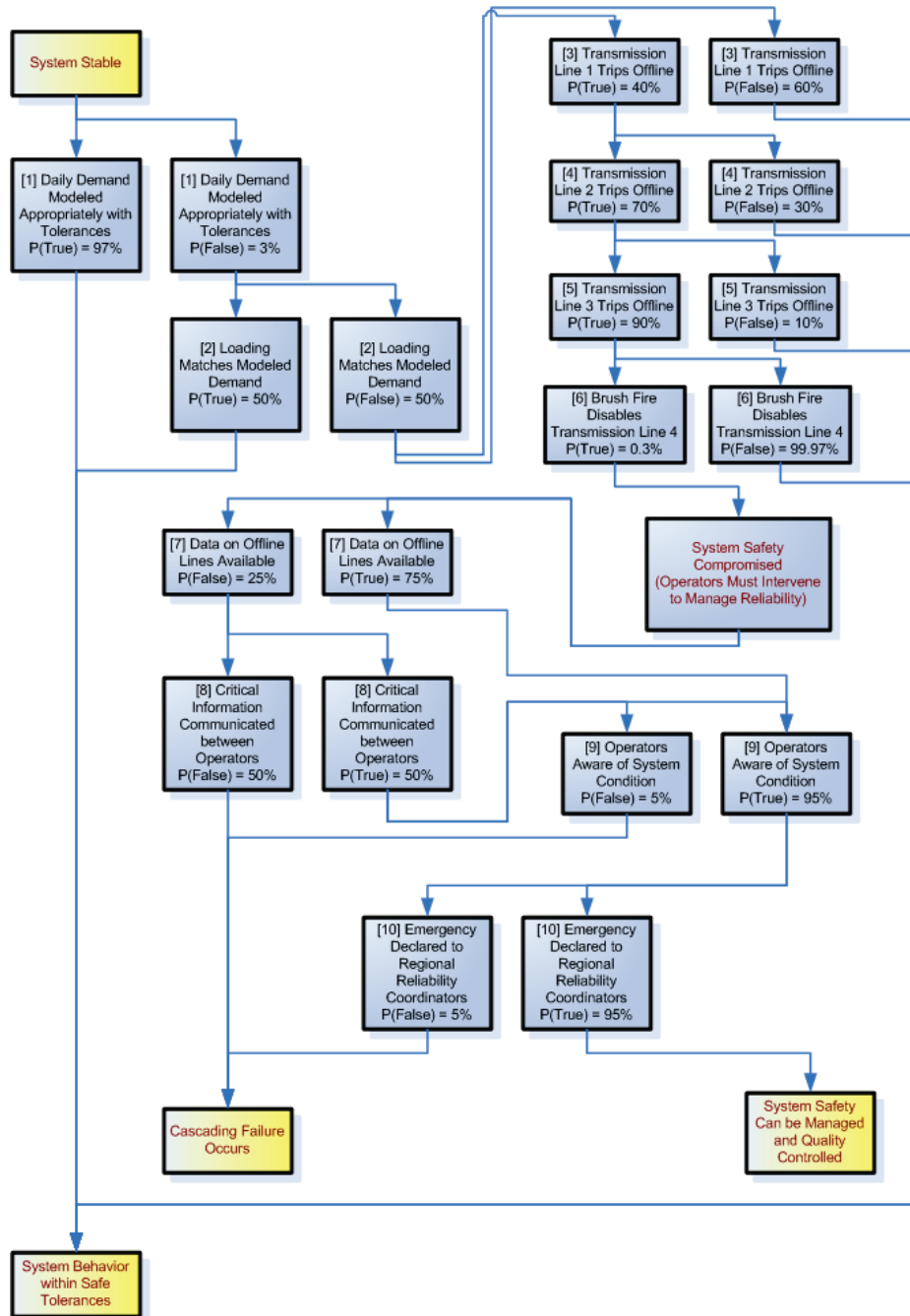
Description: Failure to Act

Parties involved: MISO, PJM, FirstEnergy (FE), American Electric Power (AEP)

Factors 1, 2, and 4 present human and organizational errors (HOE) that resulted from HOF. The failure of FE to act during a four hour window (Timeline phases 1 to 4, 12:05pm to 4:10pm) based on the preceding factors became a catalyst for the Northeast blackout during the next three minutes (Phases 6 to 10). FE and MISO were unprepared on several fronts for the conditions that presented themselves on August 14, 2003. They did not have enough real-time data to analyze the situation. Operators were unable to interpret the data they had. Operators failed to communicate with each other and as a result did not share critical knowledge of the current conditions. Also, emergency management systems were incapable of evaluating the hazardous conditions to develop policies for ameliorating the failures. These factors (poor QA/QC), fused together, lead to a failure to act to ensure the quality of the system.

Probability of Failure

In this section, an event tree analysis of the conditions required to create a cascading failure are analyzed. The events start off as hardware and software related but progress towards people related tasks. These people related tasks are the critical elements to prevent the cascading failure. Proper management of reliability and safety parameters during these events could lead to the recovery of the system as it deteriorates towards failure.



An event tree analysis is performed to determine the likelihood of success and failure of the system given certain activities and events that occurred. There are 10 events that occur and each has a possible true or false outcome. If the event occurs then it is true, otherwise it is false. The probabilities that an event is true or false were determined from several sources (detailed in the event descriptions). Although the sources did not give a quantitative probability of success or failure, they did describe the frequency with which the event was performed or occurred and from that, the likelihoods were determined.

- [1] Daily Demand Modeled Appropriately with Tolerances – Although it is extremely difficult to model demand exactly, model results for electricity demand always include a safety buffer to ensure reliability. This buffer is usually large enough to compensate for fluctuations in loading outside of the predicted loading. Data indicated [PSOTF] that in a region, approximately 10 blackouts occur per year. Given that models are run daily, this is a failure rate of about 3%.
- [2] Loading Matches Modeled Demand – Once the demand has been modeled, there is an equal chance that loads match demand (and are within the buffer). Only if the demand was modeled incorrectly (or was underestimated) and loading was out of the buffer, can components of the system begin to fail. This is because usage has exceeded the predicted demand and its buffer.
- [3] Transmission Line 1 Trips Offline – With loading outside of safe limits, system components will go offline. This results from more load on the system than there is generating capacity. In this failure, a major transmission line from Pennsylvania to Ohio was the first to go offline. Although buffers in the line were not explicitly stated [PSOTF], it was assumed that a line could sag (factor of safety) 40% before it came in contact with the tree in Ohio that caused it to short circuit.
- [4] Transmission Line 2 Trips Offline – Although the same 40% could be assumed for the second 345 kV line that tripped on August 14, it is important to consider that this line had a higher likelihood of failing given that the first had failed. Lines 2 and 3 were now experiencing higher loads because the first was offline. There was extra loading on this line making it more likely to fail.
- [5] Transmission Line 3 Trips Offline – Similar to events 3 and 4, line 3 now had the highest probability of failure because it was carrying load from two other lines that had gone offline. With the first two lines down, line 3 was not likely to handle the loading unless reliability coordinators rerouted electricity through other paths.
- [6] Brush Fire Disables Transmission Line 4 – The likelihood of a brushfire occurring was calculated as a function of temperature and precipitation. Given high summer temperatures and drought conditions for the region, the likelihood of a brushfire occurring was only one day per year ($1 \div 365 \approx 0.3\%$).
- [7] Data on Offline Lines Available – Now that four transmission lines have gone offline, the system safety has been compromised and operators must intervene to manage reliability and perform quality control. FirstEnergy at this event did not have data on many of their lines [PSOTF] because of poor maintenance practices. As a result, approximately 25% of their transmission lines were not reporting live system conditions. This led to a 25% likelihood that FirstEnergy would not have the information they needed from the system to know which lines were down.
- [8] Critical Information Communicated between Operators – It was necessary to communicate critical information between operators when the system reporting tools were not functioning correctly. Given poor communication training and the physical separation of operators, it was estimated that there was a 40% likelihood that this information would be shared.
- [9] Operators Aware of System Condition – If critical information was not shared then there was still a very high likelihood that operators would be able to recognize the failing state of the

system. Operators should have been receiving many calls from customers and maintenance workers (which had been deployed to the field in response to the automated messaging system not working) indicating that critical components were not working. Operators had extensive training to recognize these specific scenarios and take the proper action to notify regional reliability coordinators.

- [10] Emergency Declared to Regional Reliability Coordinators – Similar to event 9, many signs indicated the cascading failure state of the system. Operators were trained to call their regional reliability coordinators to notify them of the system state so that emergency procedures could be implemented.

The error rates for many of the events on the tree (excluding events 8, 9, and 10) are estimated at unity. This is because events 1 through 7 are not human tasks but machine tasks. The probability of those events failing is the probability of failure. For events 8, 9, and 10, this is not the case because of human factors. For these events, error rates were assigned to them based on the framework created by Bea²⁶ for mean probability of human error given the complexity of a task. For event 8, a highly complex task with considerable stress and little time, an error rate of 10^{-1} was assigned. Operators, although trained for this state of the system, were not trained for the conditions in which they had to operate to address this state. For event 9, an error rate of 10^{-1} was again assumed. Similar to event 8, operators were required to evaluate the state of the system under highly stressful conditions given limited resources. Lastly, for event 10, operators were required to pass the information on their system the regional reliability coordinators. In this event, operators were forced to make decisions with partial information and a system that had already begun to cascade. This event was assigned an error rate of 0.5 as operators were required to perform a rare task under extreme stress and much impairment.

Given the outline of major events associated with the process, there are three ways in which the system could result in cascading failure. These three scenarios will now be detailed and their probabilities of failure calculated. Given the highly dependent nature of this system, it is assumed that the individual events are also dependent.

Scenario 1

The most direct route to cascading failure is through this scenario. In Scenario 1, event 6 has occurred and now operators must intervene to manage reliability. At event 7, operators do not have the information needed on the state of the system consolidated. At event 8, operators fail to communicate what information they have on the state of the system to each other. This is what happened on August 14, 2003. Using the probabilities determined in the event tree analysis and determining the probability of failure given the errors, the following table is derived.

Table 1: Pf for Events of Scenario 1			
Event	P(Failure)	Error Rate	P(F E)
1	3.0%	1	3.00E-02
2	50.0%	1	5.00E-01
3	40.0%	1	4.00E-01
4	70.0%	1	7.00E-01
5	90.0%	1	9.00E-01
6	0.3%	1	3.00E-03
7	25.0%	1	2.50E-01
8	50.0%	0.1	5.00E-02
π			1.42E-07

The probability of failure is the product of the dependent events in the system. For this scenario the probability of failure is 1.42×10^{-7} .

Scenario 2

This sequence of events differs from the first after event 7. Although system state data is not available, operators communicate with each other (event 8) and are able to gather enough understanding of the events to know the system is undergoing problems. Unfortunately, operators don't know (event 9) that the problems have pushed the system out of safe operating limits. As a result, they do not begin emergency management procedures. The table below summarizes the probability of failure for this scenario. For this scenario the probability of failure is 7.09×10^{-10} . It is smaller than scenario 1 because it is less likely to happen. More events are involved providing greater chance of managing reliability.

Table 2: Pf for Events of Scenario 2			
Event	P(Failure)	Error Rate	P(F E)
1	3.0%	1	3.00E-02
2	50.0%	1	5.00E-01
3	40.0%	1	4.00E-01
4	70.0%	1	7.00E-01
5	90.0%	1	9.00E-01
6	0.3%	1	3.00E-03
7	25.0%	1	2.50E-01
8	50.0%	0.1	5.00E-02
9	5.0%	0.1	5.00E-03
π			7.09E-10

Scenario 3

In the final scenario that directs the system to cascading failure, operators now have information on the state of the system (event 7). They know which lines have gone down. Aware of the system state (event 9), operators must decide to call the regional reliability coordinator so that emergency procedures can be implemented to control the problem. Unfortunately, communication breakdowns prevent operators at FirstEnergy from doing this. This scenario has a probability of failure of 3.54×10^{-10} .

Table 3: Pf for Events of Scenario 3			
Event	P(Failure)	Error Rate	P(F E)
1	3.0%	1	3.00E-02
2	50.0%	1	5.00E-01
3	40.0%	1	4.00E-01
4	70.0%	1	7.00E-01
5	90.0%	1	9.00E-01
6	0.3%	1	3.00E-03
7	25.0%	1	2.50E-01
9	5%	0.1	5.00E-03
10	5%	0.5	2.50E-02
π			3.54E-10

Violations in Operator Performance

The violations by FE of NERC policy created conditions for which desirable quality and reliability of the system could not be achieved. During the four hours prior to the cascading failure, if FE had followed NERC procedure then the system could have remained functional. FE, however, had not established a foundation within the organization to follow NERC policy.

The events of the power outage began when three 345 kV transmission lines in central Ohio came in contact with trees that had not been pruned (NERC policy does not specify the frequency with which trees near power lines must be checked). Each reliability organization has a coordinator responsible for estimating demand on the region and coordinating operations of the organizations beneath it. The estimate for electricity use on this day was not correct and reliability organizations (including FE) in the region were not generating enough capacity. When the transmission lines went offline, generators in the regions had to provide for the extra customers. To protect themselves, these generators automatically tripped offline to prevent mechanical systems from failing. As generators in the region tripped off, more electricity was required by import causing additional transmission lines to go offline. This circular effect continuously occurred during the four hours and five minutes prior to the cascade. The occurrence took place in FE's reliability region. If FE had followed NERC policy, they would have been able to more effectively control this circular effect mitigating future hardware from going offline and ultimately the cascade that affected four states and one Canadian province.

Before identifying the initiating, contributing, and compounding roles that FE played in contributing to the failure, it is necessary to review NERC policy to understand what exactly the violations were. In response to the US-Canada Power Outage Task Force report²⁷, NERC rewrote their policies²⁸ with the goal of reducing the likelihood that similar failures would occur. The old manual²⁹ becomes inactive on April 1, 2005 when the new manual³⁰ takes over. There are two primary (directly related to failure of the system) NERC policies and several secondary (indirectly related to failure of the system) that FE violated contributing to the failure. These policies, listed below, have been paraphrased from the NERC operating manual:

Primary NERC Policies

- Policy 2, Section A, Standard 1 – All control areas shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.
- Policy 5, Section A – To facilitate emergency assistance, the operating authority shall inform other potentially affected operating authorities and its reliability coordinator of real time or anticipated emergencies conditions, and take actions to avoid when possible, or mitigate the emergency.

Secondary NERC Policies

- Policy 5, General Criteria – Prompt action should be taken to relieve abnormal operating conditions from a downed transmission line.
- Policy 2, Section A, Standard 2 – In the event of unsafe operation, measures should be implemented to return the system to security limits within 30 minutes.
- Policy 5, Section C, Requirement 2 – Generation and transmission should be used in the fullest extent possible in an emergency to return the system to security limits.
- Policy 2, Section A, Requirement 1.2 – A load reduction program should be implemented during emergency conditions to return the system to security limits.

- Policy 6, Section B, Emergency Operations Criteria – Effective emergency operating procedures should be exercised when security limits have been breached.
- Policy 5, General Criteria – Reliability organizations should have and be able to implement a manual load shedding program in emergency conditions.

The violations of these primary and secondary policies occurred prior to the initiation of the blackout and during the failure sequence of events. They did not occur at just single individuals but all across the FE organization. Operator performance will be analyzed through the conceptual framework presented by Professor Bea³¹. In this framework, errors are defined as “the inadvertent straying of actions from the action sequence to the intended outcome.” Violations, however, are “defined as deliberate, but not necessarily reprehensible, deviations from those practices deemed necessary to maintain in the safe operation of a potentially hazardous system.” The violations that occurred by FE operators were the result of poor training, inadequate information, and misguided expectations that had been bred by the organizations within the system. Upon the initiation of the events leading to the failure, FE operators did not understand the system to know there was a series problem, did not have all of the information needed to address the problem, and thought they could bring the system under control even as it cascaded into a state of emergency. The following section details the violations of operators based on the NERC policies described previously:

Primary NERC Policies

- Policy 2, Section A, Standard 1 – When the Chamberlain-Harding 345 kV line went down, operators were unable to return the system to a safe state. FE operators did not understand how the system was behaving, share the information necessary to make decisions (it was discovered that critical information was not shared by parties even though they were across the hall from each other), and inform other reliability coordinators of the impending emergency. There are several processes involved in this step. Identifying the entire system’s volatile behavior was knowledge based as it was an emergency situation. Prior to this however other processes should have taken place. Given proper training, reacting to downed major transmission lines should have been skill based for the operators. Also, the sharing of information should have been rule based.
- Policy 5, Section A – As FE’s system continually degraded, operators did not communicate this information to other regional reliability organizations to alert them of the potential emergency. Although FE operators were forced to analyze the state of the system with non-real-time data, there was a point where they should have declared a state of emergency. This is a rule based behavior. FE did not declare the emergency until well after, leaving little time for other reliability organizations to adapt.

Secondary NERC Policies

- Policy 5, General Criteria – As mentioned in the first violation, FE did not promptly take action to relieve the security violations of their system. The practice of shifting electrical loads is a skill based behavior for operators. FE did not exercise this behavior because they did not have sufficient data to address the system.
- Policy 2, Section A, Standard 2 – The timeframe given for operators is 30 minutes to bring their system back from security limits. Training takes place teaching operators how to address the system and react accordingly in this timeframe. Based on this training, this process is skill based and was not exercised by FE operators.
- Policy 5, Section C, Requirement 2 – As transmission lines and generators went down, FE operators should have been able to address the system through skill and rule based behaviors as mentioned previously. Because this information was not available, operators were forced to dispatch technicians to provide real-time diagnostic information from the field.

FE operators turned what should have been a rule based behavior of evaluating the system condition from their control center to a knowledge based behavior having to adapt to the resource limitations.

- Policy 2, Section A, Requirement 1.2 – FE operators had been trained for this emergency condition but did not exercise proper reactions to the security violations. This should have been a rule based process but because of how operators addressed the behavior, turned it into a knowledge based process for which they had little knowledge of addressing (critical information was missing and not shared).
- Policy 6, Section B, Emergency Operations Criteria – All reliability organizations on the electricity grid are responsible for having a load shedding program for this situation. The program includes evaluation of the system and proper reaction to prevent cascade. As illustrated with the violations above, FE did not have a proper program. The process of creating the program was a rule based process based on the NERC policy requirements.
- Policy 5, General Criteria – Similarly, NERC requires that operators should have skill to analyze security violations when automated systems cannot. It was apparent that FE's operators did not have this skill as the blackout occurred.

The mitigation of these violations is critical to the future success of this system. The 2003 blackout was a reproduction of the 1963 and 1968 blackouts which occurred in the same region. Although policies were improved from the first two outages, it is apparent that new policies must be developed to enforce the behaviors described previously. One of the biggest problems with the current structure of reliability organizations is that they operate according to NERC policy based on mutual self interest. If they violate policy then they physically cannot operate on the grid and risk their business. Currently, an organization that violates policy cannot be punished. NERC and its policies are vital to the reliability of the system. Reliability for these organizations should be mandatory and enforceable by legislation. This is perhaps the most practical method for ensuring compliance to the NERC policies. Secondly, FE operators should be trained to understand their own organization including where critical information is located and who has access to it. As illustrated previously, operators were forced to make decisions based on sparse sources of data. If this event were to occur again, they should know what groups within the company have the information they need to make decisions. Operators did not exercise their skill based processes of shifting electrical loads when security violations occurred. FE operates in a somewhat geographically constrained region. The organization should reinforce in their operators how to shift loads appropriately. The rule based behavior of understanding the emergency condition and reacting appropriately was not exercised appropriately by FE operators. Operators should undergo training to enforce the appropriate understanding of the system during security breaches. Also, the skill process of reacting to this emergency must be completed within 30 minutes. In four hours during this failure, FE operators were unable to react. Evaluating the rules to determine emergency conditions should be complemented with the skill of executing critical decisions.

The mitigation suggestions mentioned previously are diverse in the processes required to handle the system. In such a large and technically complex system, there are many components that must be managed by different processes. It is essential that operators have the skills necessary to evaluate and react to not just routine conditions, but also security violations. Similarly, these operators must understand how their portion of the system is behaving so that they can apply the rules that they have been taught to understand the direction for which the system is heading. Additionally, operators cannot merely form processes based on skills and rules, they must have cognition of the system to understand unscripted events that they have not had specific training for. During this outage, FE operators did not have these cognitive factors at many different levels of the organization. These lapses created an alignment of the holes in the systems defenses allowing failure to occur.

Proactive

Proactive approaches are used to analyze systems for safety, durability, serviceability, and compatibility prior to failure or losses in quality. According to Bea³², the proactive approaches are “intended to allow one to study the physical aspects of systems and procedural – human aspects in their present or proposed form, identify potential improvements and critical flaws, and identify how best to improve the quality of the systems and procedures.” The approaches are sometimes quantitative, sometimes qualitative, and sometimes both. In this section, I will analyze the proactive approaches (and lack thereof) that reliability organizations on the grid used to understand how the system was behaving. The manner of failure of this system indicates that proactive approaches were either used incorrectly or not used at all. To understand the proactive approaches used by reliability organizations, I will detail several of the NERC policies relating to the practice and then identify how the reliability failed to perform the policy’s terms and why.

FirstEnergy failed to conduct long term planning studies and did not analyze its system under extreme operating conditions. In June of 1994 and summer of 2002, disturbances in the Cleveland-Akron area forced the regional operator to load shed to protect the system. An inability to respond to two minor disturbances in electricity operations led to several analyses performed on the robustness of the regional network. AEP, a regional provider adjacent to FirstEnergy’s region, was worried about the sensitivity of the area and the inability of FirstEnergy meet reliability standards in the region. AEP shared their audit of FirstEnergy’s system problems with them on January 10, 2003 and May 21, 2003³³. AEP employed both a quantitative and qualitative proactive approach to understanding the deficiencies in the system. Although FirstEnergy did make some changes to the troubled areas of the network, they did not build in enough robustness into a very sensitive area. Furthermore, the reliability studies that FirstEnergy used to test its system were not nearly broad enough to understand the effects of the events that occurred on August 14 leading to failure.

FirstEnergy did not understand the system’s voltage criteria and as a result, how it would behave under extreme operating conditions. Because of a poorly detailed NERC policy (discussed later in this section), FirstEnergy set their equipment to a 90% threshold. This meant that when supply was less than 90% of demand, emergency alarms would sound. Neighboring systems had their minimum voltage levels set to 95%. Not only was FirstEnergy’s voltage levels set too low for alarms but they were set at a threshold where if breached, FirstEnergy would have significant difficulty recovering. As the FirstEnergy became more and more strained, equipment (with low voltage limits) began to trip offline to protect the integrity of the system. Data from August 14, 2003 collected by the US-Canada task force indicates that reserve power supplies were ready but not being used in the region. If FirstEnergy had increased their safety limits then these reserves would have had a higher likelihood of being used. Between 1986 and 2002 peak demand for electricity in the US grew by 26% while during the same period capacity increased only 22%³⁴. The need for access to reserve power has become more important in the past two decades and an inability to get to it has more severe consequences.

The East Central Area Reliability Coordination Agreement (ECAR) did not audit FirstEnergy and allowed the provider to operate with inappropriate voltage criteria. The process that ECAR uses to understand reliability in their system is to compile the self audits of companies below them such as FirstEnergy. ECAR does not specify and minimum level of detail but simply accepts the provider’s analysis and then compiles them for its own analysis. This process led to an

understanding gap of the inappropriate voltage criteria in FirstEnergy's region. Although ECAR could perform the audit, they instead allowed FirstEnergy to self audit. Furthermore, the last study that ECAR had gathered from FirstEnergy had been performed in 2000. This study estimated system behavior three years later for the summer of 2003. Also, that last study had not included analysis of the loss of the 345kV Harding-Chamberlain line that was one of the main initiating events in the failure.

Several of the NERC operational requirements were not written with enough detail so that FirstEnergy could interpret them as they wished. NERC operating policy NPCC A-2 specifies that "acceptable voltages under normal and emergency conditions shall be maintained within normal limits and applicable emergency limits respectively³⁵." This simple, yet direct statement, does not specify what steps should be taken to ensure acceptable voltages and does not specify what practices must take place to know what "acceptable" means. NERC allowed FirstEnergy to create its own definition of "acceptable." FirstEnergy did indeed interpret this policy by setting their minimum voltage levels to 90% as discussed earlier.

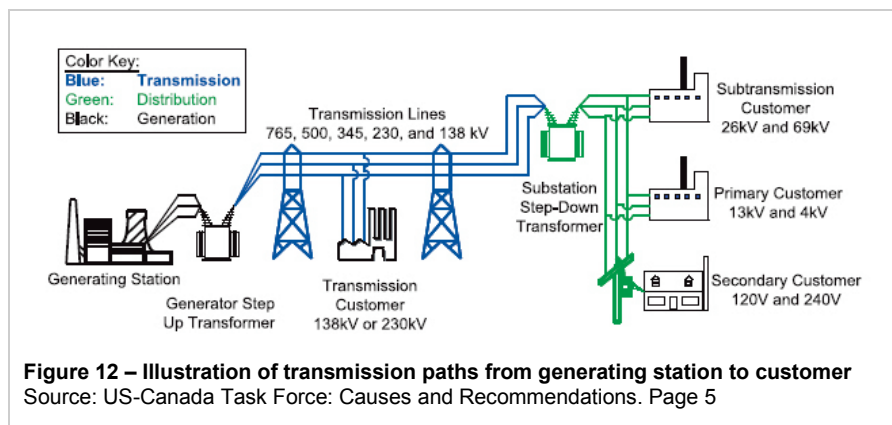
Interactive

Although there were several unknown unknowables (UU) that contributed to the failure of the system, operators could have brought the system back to operating within safe parameters. Instead, a series of unknown knowables (including non-functional monitoring equipment, poor communication practices, and the inability of operators to follow emergency procedures) let the system cascade to failure on that day. The two UU that created conditions for the system to begin operating outside of safe parameters were a transmission line that went offline because of a brush fire and the behavior of electricity on an interconnected transmission grid. These UU will be detailed further in the following paragraphs however first it is important to define what an UU is relating to the context of this failure. Bea³⁶ describes an unknown unknowable as an aspect that influences or determines the failure of a system in the future that is fundamentally unpredictable and unknowable. He goes on to say that UU are the "incredible, unbelievable, complex sequences of events and developments that unravel a system until it fails." Because unknown unknowables are not predictable, operators must implore interactive approaches to achieve safety. These quality control practices could (if effectively applied) be used to return a system to safe operating conditions. In this failure, the transmission line that went down from a brush fire and the unpredictable behavior of electricity on the grid was not enough to cause power outages. Instead, the unknown knowables prevented operators from having the necessary information to make sound decisions that would allow them to return the system to safe conditions.

The first UU that created unsafe conditions for this system was a transmission line in central Ohio that was above a brush fire eventually causing it to go offline. Brush fires have the ability to ionize the air around them. A transmission line near ionized air is at risk of short circuiting as charged particles will use this air as the path of least resistance to the ground. The failure of transmission lines due to brush fires is an UU because it is an act of nature and not predictable. It occurs during the operational stage of the system and is a result of unknowable weather information. Engineers and scientists do know when droughts have occurred, vegetation is dry, and temperatures are high enough but to predict the exact location when these fires will occur is not possible. Instead, operators on the grid must be able to adapt the system to transmission lines that go offline, rerouting electricity appropriately. Transmission lines going offline on the grid is a common occurrence. Because estimates never equal demand, transmission lines are often subject to unbalanced loading where generation at one end is not matched to loading at the other end.

Periodic circuits along the transmission lines will automatically disable them when they sense unsafe conditions. Operators in the region were not prepared to properly administer quality control procedures when this line went down allowing the cascade to continue (as will be further discussed).

The second UU is the inability for all parties on the grid (including operators, reliability coordinators, generators, or users) to control the paths of electricity through the network. The flow of electricity through transmission lines is sometimes equated to the flow of water through pipes. Although both civil



systems provide a critical resource, they operate under very different physical principles. Electricity is used the instance it is created and flows along the path of least resistance which could be a transmission line or through the air as described before. The North American power grid is composed of five different “sized” lines³⁷ (765, 500, 345, 230, and 138 kV) as illustrated in the diagram to the right. The 765 kV and 500 kV lines are primarily used to interconnect the three main power generating areas of the grid³⁸. 345 kV lines are the primary lines for transporting electricity into a region. In Ohio there are approximately one-dozen 345 kV transmission lines entering/exiting the state. Lastly, 230 kV and 138 kV lines are used to transport electricity directly to a customer. In an industrial area there would likely be 230 kV lines while in a residential area (with smaller loads) 138 kV lines are found. The inability to control electricity flows through specific transmission paths forces operators to control the system at a regional level. Operators know that electricity used by the customer will have been generated at the closest generating facility (because electricity flows along the path of least resistance). This means that if regional generating capacity does not equal regional generating load then electricity will either be needed or in excess in the region. When this occurs, electricity is imported to or exported from a neighboring region. Knowing that reliability coordinators never exactly predict demand means that this is always occurring in the grid. Although the idea is somewhat chaotic (because the region is never in equilibrium), it is also the foundation of reliability across the network. The sharing of generating capacity across regions, states, and even country boundaries ensures that when capacity is not balanced, it can be made up for somewhere else. Also, the system has buffers built in where generating facilities can step-up capacity and the transmission system can shed excess load. This unknown unknowable of the flow of electricity through the network is constantly occurring but has been managed by reliability coordinators. When transmission lines went offline on August 14, electricity flows shifted in the region to other paths so that the load that was demanded within the region was met. Unfortunately, the failure of operators to interactively handle these downed lines led to the cascading failure (uncontrolled shifting of electricity flows led to transmission lines tripping offline causing another shift).

To address these two unknown unknowables, it is important to recognize that their types (nature and the behavior of electricity) encourage reliability at the operator level. It is not possible to predict the forces of nature to within any accuracy to proactively manage risks around transmission lines. Furthermore, even if operators did know when and where these fires would occur they could possibly have to disable the transmission line so that fire crews could go near

them to extinguish the fire. In this scenario, operators would be forced to manage transmission paths proactively just like they are required to do interactively. Redundancy is built into the system to allow operators choices during times of crisis for providing quality control. Improper practices, like those followed by operators during this failure, are the direct causes of failure of the system. Secondly, addressing the unknown unknowable of behavior of electricity through the grid to provide quality control is also contingent on operator behavior. As discussed, transmission lines tripping offline is a common occurrence on the grid. Typically, operators handle this situation appropriately by using their buffers or opening and closing other transmission lines to the affected region. The grid is constrained by the physical laws of electricity which dictates its behavior. Operators must be prepared to handle this situation to keep the system operating within acceptable parameters. Operators must be trained to understand how the system works and how their region is constrained. They must know what their options are for interactively managing this problem as well as how their choices will affect the system. This was not the case during this failure as faulty data analysis tools and poor communication left operators without the necessary information to interactively craft solutions to manage the cascading failure. Instead, over four hours, they did not react allowing the cascading events to occur leaving 50 million people and critical services without electricity.

Reactive

The state of the US electricity grid is stored and analyzed by system operators through SCADA (System Control and Data Acquisition) systems³⁹. The SCADA systems track information from the field and communicate it to master stations for processing. Once at the master station, the information is passed through state estimators which model the current behavior of the system to predict future behavior. Future behavior is critical because electricity is used the second it is generated. Enough electricity must be generated based on these state estimations to match demand. On August 14, 2003, several of the field sensors in the region where the outage was starting, were not functioning properly. Although this presented challenges to operators, it did not prevent them from understanding what was happening with the system. Although the operators did not have all the information they needed, FE did have enough information to understand the current and future behavior of the system. Poor communication processes within FE prevented individuals from having the information they needed to make decisions. Also, violations of rule based behavior led to conditions where operators knew the system was in a state of emergency but did not declare it to the regional reliability coordinators above them.

The SCADA system is critical for monitoring accidents and near misses for the grid. Bea⁴⁰ notes that generally, accidents and near-miss reporting systems “do not adequately capture the important human and organizational factors that underlie the majority of these accidents.” This is true and is illustrated in Figure 13 which shows the frequency of outages from 1984 to 1997 for the US electricity grid captured by the SCADA systems but does not relate HOF to it. The SCADA system has the capacity to capture, analyze, and store the information but does not shed light on the human and organizational factors (HOF) that were involved. In the case of the 2003 blackout, the HOF factors directly affected the inability to bring the system back under safe operating conditions.

Bea⁴² indicates that attention to accidents, near-misses, and incidents can play an important role in helping to prevent failures by giving early warnings to operators of potential unsafe operating conditions. The SCADA system does not do this but instead reports the technical health of the network. Assessors must join the

SCADA data to the accidents, near-misses, and incidents related to HOF to evaluate the failure of a system. This joining of information primarily occurs when there has been a major failure (such as this blackout where approximately 50 million customers lost power⁴³) and a task force is created to understand the sequence of events. The joining of data typically occurs with inspections which are now discussed.

The importance of inspection should not be downplayed because of the complexity of this system. Inspection could have occurred on multiple levels to evaluate not only the technical readiness of the power grid but also the roles of HOF and their interfaces with the technical components. Inspections take place at primarily two levels. The first is the in-service inspections and the second is the inspection of systems post-failure to determine what happened (as discussed with the US-Canada task force).

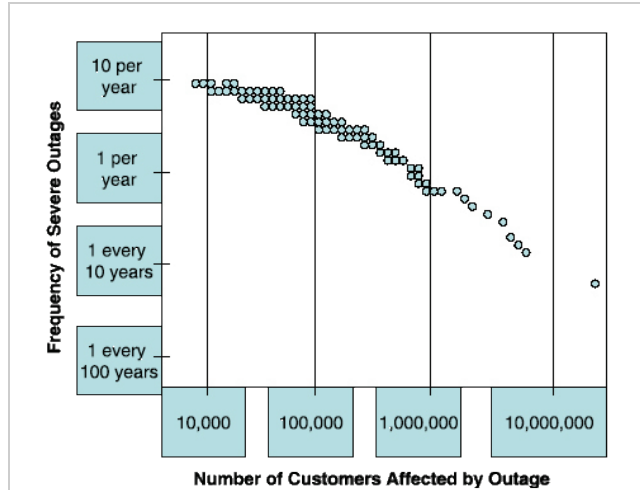


Figure 13 – Frequency of outages generated from SCADA data for 1984 to 1997

Source: US-Canada Task Force: Causes and Recommendations. Adapted John Doyle, “Complexity and Robustness⁴¹”

Utilities on the grid are not required to inspect at any given time interval or for specific events. Instead, they must adhere to the policies put forth by the North American Reliability Council (NERC) out of mutual self-interest for the success of the system. Bea⁴⁴ identifies the importance of inspecting for both intrinsic and extrinsic defects and damage of systems. The extrinsic factors on the North American electricity include weather and brush fires, both unknown unknowables that can compromise the reliability of the system. Intrinsic factors include FE’s inability to communicate critical information between individuals in the organization, the mean time to failure for specific types of hardware, and growth of tree branches near transmission lines. Inspections could have occurred to evaluate these intrinsic factors but did not. The three transmission lines that started the cascading events were the results of tree growth that should have been trimmed but was not inspected. NERC policy does not specify how often trees must be expected so FE created their own policy of performing that task only twice a year. In-service inspection policy was inadequate and un-enforceable. NERC policy is not backed by legislation resulting in an inability to punish violators. A federally required inspection program would enforce the analysis of technical and HOF factors affecting aspects of this system. In-service inspection of FE and their operational constraints could have revealed the flaws in the organization that prevented them from evaluating the deteriorating state of the system during those four hours and act to control the cascade.

Post-outage inspections do not often occur either. This is because minor blackouts occur frequently and are typically the effect of the physical limitations of the system. Because electricity is used the instance it is created, and the cost-ineffectiveness of storing it in large quantities, demand must match supply in a given region to ensure reliability. If there is more demand than supply then generators trip offline to prevent hardware failure and customers may lose power for a short period while loads are re-balanced. As demand for electricity has increased over the past few decades, the trend in generating facilities expansion has been to increase utilization of existing facilities instead of building new ones⁴⁵. This has created a shrinking margin in the electricity grid where excess capacity has been continuously decreasing. A smaller buffer has led to a reduced ability to absorb unexpected capacity and the system is therefore more vulnerable

to failure. In the past, multiple contingencies could be handled to uphold the reliability of the network but this is becoming less so. This condition of the system has created the likelihood for increased outages which are not typically inspected for HOF factors but only technical factors. NERC policy should be backed by federal legislation to enforce reliability standards. Inspections of both technical and HOF factors should be made mandatory to ensure that events such as those experienced on August 14, 2003 do not occur.

The SCADA systems and poor inspection programs related to the North American electricity grid are lacking in their ability to highlight the technical and HOF reliability factors of the system. Reliability organizations are currently operating under their self interest for the success of their region and do just enough to meet minimum requirements. More stringent policies are necessary to create higher reliability standards for all organizations in the grid. These policies must be backed by federal legislation so that they are enforceable. There are currently too many organizations operating at minimum reliability policies. It is only a matter of time before these poor policies are brought out as was seen with this failure.

Improvements & Implementation

The previous sections of this paper have documented the failure of the North American power grid on August 14, 2003 through the human and organizational factors (HOF) framework. Many characteristics of the system have been examined including the events that led to failure, parties and roles, and how these organizations proactively, interactively, and reactively managed the quality of the system. In this section, several improvements are proposed as well as methods for implementation. These improvements will incorporate past sections of this paper and the analyses performed and apply the HOF framework to the solution and implementation. It is important to recognize that the US-Canada power outage task force presented a set of solutions^{46,47} one year after the failure. Although many of the proposed improvements made by the task force are relevant, they do not necessarily capture the HOF that we have been learning. The HOF framework will be used in crafting the improvements and will incorporate some of the suggested improvements from the task force.

Institutional Changes

As mentioned several times in this report, one of the most important criteria inhibiting quality and reliability of the electricity grid is the structure of the organizations within. All organizations operate, and are compelled to meet quality and reliability standards, from mutual self interest. These reliability organizations cannot be fined but most work to maintain the stability of the grid to protect their investments. If an organization violates NERC policies but does not compromise the quality of the grid then there is no body that can set forth punishment. The Federal Energy Regulatory Commission (FERC) should start working with NERC, perhaps as a single organization, to control the reliability of the grid. The US, Canadian, and Mexican governments should give FERC the power to levy fines against violators of policy. Improved monitoring (discussed further later) of all NERC policies (including items such as tree trimming which turned out to be a catalyst in this failure) should occur by inspection at all organizational levels. Instead of several thousand independent reliability organizations, an effort should be made to create a consolidated reliability council. This should be accomplished through the same checks and balances that the organization will impose on reliability coordinators. First, all three countries must be willing to participate. If the grid has a system boundary of North America then the new reliability should have control over the entire boundary. Next, implementation should include a committee to evaluate the current reliability structure of the grid. Once the organization and its role has been established, the reliability program should be constantly monitored and reviewed for deficiencies or factors that may affect the quality of its role.

Clarifications of Existing Standards and Policies

Prior to the failure, NERC standards and policies were often too vague when action was needed and sometimes nonexistent. In the proactive analysis section, the example was given that operators set voltage monitoring alarms too low and were not aware of emergency conditions as a result. If the structure of the system includes organizations acting out of mutual self interest then policies must be specific enough that when organizations agree to follow, they actually understand what actions they must take. An example of this could be the redefining of the tree trimming policy which currently states that trees must be trimmed often enough such that they don't interfere with the operation of the transmission lines. The phrase "often enough" was interpreted by FirstEnergy to mean once a year. A more explicit statement would have forced FirstEnergy to check tree branches multiple times during the year. Also, additional language could say that during times of excessive rains or fast tree growth, branches should be monitored more. Upon implementation, NERC should repeatedly review the policies for missing pieces or deficient language. NERC should collect operator logs for how often and what parameters system components were controlled. "What if" scenarios should be performed to test the policies and make improvements.

Improved Monitoring & Compliance with Standards

The past two recommendations have touched on the necessity of improved monitoring and standards compliance but specific improvements should be made. First, in response to the failure, NERC initiated self-assessments of the reliability organizations on the grid. Although required self-assessments are useful for organizations to find where they are not meeting policies, what guarantee does NERC have that the assessments that come back are accurate. Furthermore, NERC does not have an option for imposing fines on organizations that are not meeting policies. The primary result of the US-Canada task force's review was NERC requiring increased reporting

among the reliability hierarchy. This response is not only inadequate in ensuring organizations are meeting reliability standards but does not address the more critical problem of how to improve reliability. Instead of proposing additional paperwork sent up and down through the organizations, NERC should attempt to increase the effectiveness of compliance through improved monitoring. Again, NERC should be given the authority to levy fines and should independently audit reliability organizations on the grid. Inspectors performing the audits should be trained to understand the new NERC policies and what each policy's goal is. Inspectors should be trained to understand how the reliability organizations function not just by themselves but as a network. Human, machine, and computer factors should be studied and critiqued in the context of system wide reliability.

Direct Causes

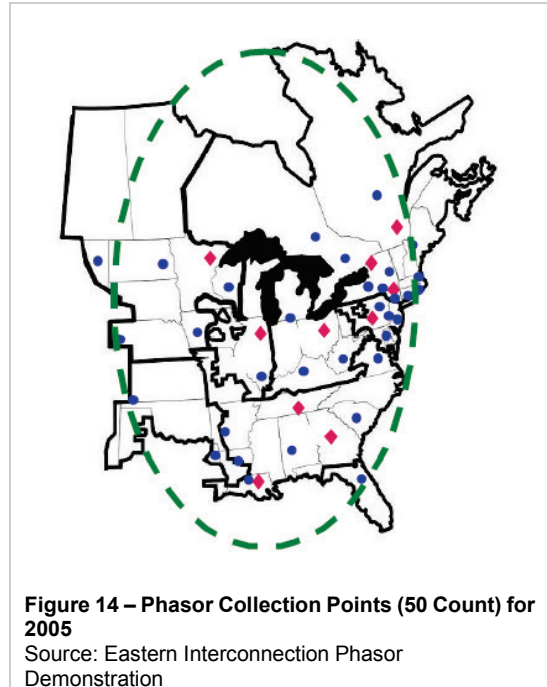
The failure of the grid stemmed from a lack of quality and control in the FirstEnergy Ohio region. FirstEnergy violated several NERC policies and added instability to an already sensitive area of the grid. In addition, regional coordinators failed to monitor FirstEnergy to identify these instabilities and perform proactive corrections prior to failure. After the failure, the Federal Energy Regulatory Commission investigated FirstEnergy and forced the organization to perform several corrective actions (including better tree trimming practices, renewed operator training, fixing of hardware malfunctions, and adjustment to safety parameters). FERC followed up on FirstEnergy after the corrective actions were taken to check if the company was continuing the fixes. Although FERC took the initiative to address the sensitive area, they target a symptom and not the problem. FERC will eventually step back from its policing role of FirstEnergy and the company will revert to operating under NERC guidelines (already proven ineffective). This scenario has already played out as previously discussed where in two separate years prior to the event this particular region had problems and fixed them only to find them occurring again. FERC must combine its power to punish with NERC policies in order to begin addressing the problems of reliability in the system. Targeting FirstEnergy violations ignores the true failure in reliability which is that organizations can operate however they chose. FERC and NERC should implement the institutional changes already discussed before they try to address the problems at the lowest levels of the system.

Operator Training and Certification

After the blackout, NERC created new policies for system operators for five days per year of emergency training. In response to FirstEnergy operator's failure to communicate critical data, recognize the deteriorating state of the system, and notify reliability managers above them, operators will now undergo additional training to address these problems. Additionally, the problems that operators face during this training will not be from a manual but will instead require them to use the tools they have to understand and address the system condition. Although this policy is beneficial, additional recommendations can be made to improve the quality of the training. First, operators should be trained to understand not only their portion of the network but also how their entire region functions. It is critical that operators understand system goals before understanding component goals. Secondly, training should include tools and techniques for understanding not just computers and machinery but also people. The possibility existed in this failure that if operators communicated across the hall to others then critical information could have been shared for better decision making. Training should address this problem and teach operators the proper practices related to interpersonal communication.

Monitoring Tools

The lack of communication between operators was not the only performance shaping factor that contributed to the failure. A lack of real-time data prevented operators from knowing what components of the system were operating with certain behaviors. Currently being implemented and expanded is a project known as “Phasor” run by the Department of Energy⁴⁸. This project is aimed at bridging the data gap between reliability organizations. It currently networks 50 sensors across critical junctions in the Northeast and sends the data to all reliability operators. Instead of reliability left in the hands of a single group of operators, an entire region will now have summary information of system performance. Upon implementation, it will be critical for NERC to train reliability coordinators to understand and incorporate this information into their roles. The goal is not to turn area reliability coordinators into regional reliability coordinators but to provide another method for which reliability can be checked and controlled. Operators will have to be trained how to interact with this information. If problems are showing up but flags are not being raised then operators should know what procedures to take to communicate their analyses. Implementation should not consist of NERC dropping the system into the laps of operators and walking away. Training on how to interact and communicate this system will be critical in a new protocol of technical analysis.



Voltage Management

Previously in this report, mismanagement of voltage loads was brought up as a key factor in this failure. FirstEnergy did not have adequate understanding of its generating facilities such that when the system became compromised, they were unable to properly shift loads to ensure reliability. NERC has not come up with a suitable response to this problem after the failure. They have suggested that FirstEnergy review their voltage management practices but have not specified what actions should be taken to improve them⁴⁹ or what policies should be updated to correct the problem. An investigation is warranted of FirstEnergy’s voltage management practices. The result of the investigation should include recommendations not just for FirstEnergy but for all operators on the grid. If FirstEnergy was able to loosely interpret NERC policy and create compromises in quality then other organizations will eventually follow. Again, addressing the problems that FirstEnergy had is necessary but not complete. An analysis of system wide voltage management practices should be carried out. NERC must set guidelines for how people, machines, and software manage voltage during normal and abnormal operating conditions. Independent investigations should be carried out to repeatedly review organizations and their adherence to the new NERC policy. Furthermore, based on these investigations, the policy should be revised to reflect issues of concern related to quality and reliability.

Validation

In this paper, several analyses were performed to determine the human and organizational factors that contributed to the failure on August 14, 2003. Based on these analyses, recommendations for improvement were suggested as well as implementation guidelines to improve the quality and reliability of the grid, especially in the Cleveland-Akron area of Ohio. Although several improvements have already been made based on the findings of the US-Canada power outage task force, they do not operate in the framework developed by Bea and often do not consider the human and organizational factors. It is important however, to validate recommendations from this report with suggestions for improvements from others. This will be done through the review of two findings which each proposed new guidelines for the electricity network.

Task force review

The US-Canada power outage task force was created soon after the electricity grid failure to analyze the faults of the system and propose solutions for future operations. Although an extensive review of the task force's findings was incorporated into this report, their recommendations were made under a different framework. The improvements the task force suggested were different than the solutions in this report in that this report makes recommendations based on the human and organizational factors taught by Bea. Some of the findings in this report make similar suggestions for improvement compared to the task force. The primary difference is that the task force stops with their improvement prior to implementation and usually does not consider more than one organization up the organizational pyramid. For example, the task force suggests that operators need better training in emergency response recognition and actions. They go on to suggest that retraining every year is necessary. Although this suggestion is justifiable (considering operators failed in many respects to recognize emergency conditions) and validates some of the suggested improvements in this report, it is not comprehensive. This report goes on to suggest that re-training should teach operators to use their skills and tools to evaluate system conditions instead of being taught how to react to specific situations. Additionally, operators should be taught best practices for inter-organizational communication as well as external communication with other reliability organizations. The task force recommendations can be considered "band-aid" fixes which do not tackle the human and organizational issues within the reliability framework of the grid. Although some of their recommendations agree with this reports, it is necessary to go a step further to understand the true failures of the system.

Senate Hearing

In February of 2004, approximately six months after the failure, the 108 US Congress Committee on Energy and Natural Resources convened calling several key players in the electricity grid's reliability organizations to testify⁵⁰. Among those called included Michael Gent^{51,52}, CEO of NERC, James Glotfelty, Office of Electric Transmission and Distribution, Phillip Harris, President of CEO of PJM Interconnection, LLC, and James Torgerson, President and CEO of Midwest Independent Transmission System Operator, Inc. The testifiers were told to review the findings from the US-Canada power outage task force and present their own recommendations for improvements. Although each testifier was acting in the best interest of their organization, a common theme was

presented by most of them. This theme related to the clarification of standards and protocols to manage reliability in the grid. The presentation of the testifiers confirms recommendations for improvement in this paper. The testifiers expressed their inability to operate effective reliability standards with unclear rules and guidelines. They pointed out the NERC policies specifically and made a case to the Senate to allow audits and reviews of these guidelines. These representatives presented quick fixes for much more involved problems. Revising the NERC policies is warranted (as discussed several times in this report) but must be combined with proper implementation practices, new enforcement techniques, increased inspection, and additional training. The testifiers present suggestions that agree with this report's findings but must be studied through the human and organizational factors that will directly affect quality and reliability.

Conclusions

The objective of this report was to study the failure of the North American electricity grid on August 14, 2003 and suggest improvements to improve quality and reliability. Through the Human and Organizational Factors framework, several analyses were performed to increase system understanding and analyze factors that led to degradations in quality and reliability. The suggested improvements are aimed at robust quality criteria and not simple hardware and social malfunctions. The grid is an extremely complex system with many different complexities of technology, thousands of independent reliability organizations, and a loose set of guidelines attempting to hold it together. The failure that occurred on August 14, 2003 was not unbelievable and in fact a repeat of past events^{53,54}. The reliability structure has not been revised since the inception of the grid and is continually expanding as more and more electricity players enter the system. The US government has not created an enterprise that encourages success of the system. The regulating bodies have limited abilities to inspect components and organizations that do not follow policy will likely not be punished. Furthermore, the primary motivations of the organizations in the grid are not reliability but profit. A restructuring of the grid is a must for the future success of such a critical system. The improvements suggested in this report will help achieve reliability but eventually a complete restructuring of organizations and motivations will be needed.

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