1991 System Disturbances

Review of Selected
Electric System Disturbances
in North America

North American
Electric
Reliability
Council

1991

System

Disturbances

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Foreword

This review of selected bulk electric system disturbances and unusual occurrences that occurred during 1991 was prepared for the Operating Committee of the North American Electric Reliability Council (NERC) by its Disturbance Analysis Working Group (the "Group").

Since 1979, NERC has been publishing its findings on bulk electric system disturbances, demand reductions, and unusual occurrences. Its objectives are to share the experiences and lessons that North American utilities have learned, suggest ways that utilities can apply the NERC Operating Criteria and Guides to their operations, and determine if the Operating Criteria and Guides and Planning Policies and Guides adequately address the normal and emergency conditions that occur on the bulk electric systems.

The Group appreciates the assistance received from the utilities whose disturbances are analyzed in this review.

Please address questions on the details of the analyses in this report to NERC at 609-452-8060.

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Introduction

The U.S. Department of Energy (DOE) has established requirements for reporting electric system emergencies that are listed in **Appendix A**. These emergencies include electric service interruptions, voltage reductions, acts of sabotage, "unusual occurrences" that can affect the reliability of the bulk electric systems, and fuel supply problems. When a utility experiences an electric system emergency that requires reporting to the DOE, the utility sends a copy of the report to its Regional Council who then sends a copy to NERC.

The annual review of system disturbances begins in November when the Disturbance Analysis Working Group meets to discuss each disturbance reported to NERC so far that year. The Group then contacts the Regional Council or utility(ies) involved and requests a detailed report of each incident. The Group then summarizes the report for this Review and analyzes it using the NERC Operating Guides as the analysis categories. (A list of these categories is found in **Appendix B**.)

The Commentary section includes the conclusions and recommendations that were formulated from the analyses in this report plus the general experiences of the Working Group through the years.

In 1991, utilities reported 30 incidents of system disturbances, load reductions, or unusual occurrences. This is six fewer than reported in 1990. They are listed chronologically in **Appendix C** and categorized as:

- Twenty-one system interruptions that resulted in loss of customer service
- Two public appeals to reduce demand
- Seven unusual occurrences that did not cause a service interruption
- No voltage reductions

This report contains analyses of 12 incidents, plus a report on the geomagnetic disturbances that occurred in 1991. Each utility or Region approved its analysis in this report.

On pages 9 and 10 is a Table of Disturbances by Analysis Category that offers a quick review of the categories applicable to each incident. **Appendix D** is a Summary of Disturbances by Category, which is a more in-depth summary of the incidents grouped by analysis category.

Commentary

The following discussion highlights the major conclusions and recommendations that the Working Group has drawn from the analysis of the system disturbances of 1991. Coupled with each conclusion is a summary of the experiences gained from a critical review of each incident. The translation of this experience and the corresponding lessons learned are left for the readers to apply to their unique system conditions. Accordingly, the readers are encouraged to review the analyses that follow this section to gain insight into the events that surround each incident.

Protection Systems

With its vast size and exposure to the elements, it is no wonder that the transmission system is the site of most disturbances. Usually, the protection system, with its relays, breakers, underlying control logic, and communications systems, confines transmission problems to the failed equipment without interrupting customer service. Occasionally, the protection system does not work correctly and removes, either directly or indirectly, more of the system than intended.

References: Pacific AC Intertie Separation — March 4, 1991
Four Corners Units Trip — July 16, 1991
TVA South Nashville Substation Fault — August 8, 1991
SE Idaho/SW Wyoming Outage — September 12, 1991
Pacific AC Intertie Separation — November 17, 1991

Recommendations:

- Test relays as part of the entire protection system.
  - Design should accommodate testing relays without removing plugs and connectors.
- Carefully manage temporary modifications to protection systems.
  - Submit changes to system protection design or engineering personnel for review beforehand.
  - Document and track until restored to normal.
- Test logic design to be sure it meets system requirements.
  - Document logic in clear, understandable language.
  - Recognize that complex logic often aggravates disturbances.
  - Closely track and document logic design and changes.
  - Ask EPRI to look into protection system logic as it relates to Flexible AC Transmission Systems (FACTS) applications.

- Consider redundant and local backup protection to limit the effects of protection on system failures.
- Monitor the status of special protection systems.

Communications

Underlying the transmission system is a communications system no less vast and critical, not only for information gathering and exchange, but also for control. System operators must be able to communicate with the power plants and their colleagues at adjacent and remote utilities to understand the condition of the bulk electric system and coordinate restoration after a disturbance. Communications circuits that are routed through a "hub" may fail simultaneously should that hub fail. Critical circuits and remote terminal units should not depend solely on an ac power supply.

References: Illinois/Indiana Ice Storm — March 12-13, 1991
American Electric Power, Allegheny Power System, PJM Interconnection
Severe Thunderstorms — April 9, 1991
Four Corners Units Trip — July 16, 1991
SE Idaho/SW Wyoming Outage — September 12, 1991

Recommendations:

- Provide backup power supplies to critical communications facilities and remote terminal units.
- Automate the exchange of status of key facilities and special protection systems affecting interconnected system operations.

Design and Construction

Leakage current, which usually occurs without consequence in steel or concrete utility poles and towers, can start fires on wood poles. This report visits the second fire on the same wood pole in five years, both caused by leakage current and the not-always-obvious relationship between guy lines and pole hardware.

Reference: Virginia Power Hayfield Substation Pole Fire — April 13, 1991

Recommendation:

- Review field modifications to transmission and substation equipment, especially after the changes are considered complete.

The *1990 System Disturbances* report addressed cascading transmission line failures that occurred from storms. In 1991, ice was a major culprit in collapsing transmission lines, and some towers simply folded accordion-like under the weight of the ice on the lines.

Commentary

References: Illinois/Indiana Ice Storm — March 12-13, 1991
Iowa/Minnesota/Nebraska Ice Storm — October 31, 1991

Recommendations:

- Review construction practices to assess the potential for cascading structure failure, especially on critical facilities or areas prone to extreme weather. Consider the scope of manageable reconstruction efforts when establishing the distance between cascading stops (deadend structures). (From the *1990 System Disturbances* report — integrate transmission design with facility emergency reconstruction strategies and plans.)

- Design transmission lines to fail in a way that minimizes their damage. For example, provide strain relief points to allow conductors to drop without destroying the tower.

Operations Planning and Contingency Analysis

Operations planning and contingency analyses are needed to determine how the system will react to component failures. From these studies, utilities can adjust their generation commitment, dispatch, and interchange to ensure stable operations. Even seemingly innocuous contingencies, such as a single generator failure, can affect a large area, especially if that area is sensitive to voltage instability. Whenever the generation or transmission system changes — and good examples are the collapse of transmission lines from ice or storms — the affected utilities must conduct transfer capability studies to set new transfer limits. Also, these studies should show what steps are needed to return the utility to single contingency operation as quickly as possible.

References: Duke Power Company Belews Plant Outage — July 24, 1991
Iowa/Minnesota/Nebraska Ice Storm — October 31, 1991

Recommendations:

- Conduct voltage stability margin analysis as part of operations planning and in real-time.

- Examine reactive resources to be sure they are adequate for contingencies, including support for a reasonable level of planned and emergency interchange.

- Review work by EPRI in areas of voltage stability and collapse, and review NERC's *Survey of the Voltage Collapse Phenomenon* reference document for a better understanding of voltage contingencies.

- Study various contingency scenarios to determine whether the system can quickly return to single-contingency operation.

- Review transfer capability between control areas and Regions following loss of transmission, especially if repairs are not expected to be completed for long periods.

- To the Operating Committee: Consider making Guide V.A., "Operations Planning — Normal Operations," Recommendation 2.4 a Requirement as modified:

"Each control area ~~should~~ shall participate in studies with other systems, ~~when required,~~ to consider the operating limitations of the system when transmission facilities are scheduled or forced out of service."

Power Supply

System operators must have as many controls of both power supply and load management at their fingertips as possible. As they make quick decisions to prevent load shedding, there must be few — if any — "layers" between their decisions and action. The utilities in Florida were well prepared to handle their spring capacity shortage, relying on direct system operator control and widespread public appeals. (See also the *1989 System Disturbances* report for a similar incident.)

Reference: Florida Capacity Alert — April 29, 1991

Recommendations:

- Review all plans for reducing customer demand.
- Review system operator's ability to activate load control programs, such as demand-side management and load shedding.

Geomagnetic Disturbances

The effects of the geomagnetic disturbances (GMDs) in 1991 were much less than the March 13, 1989 event for two reasons: First, the GMDs were less severe and, second, the utilities implemented steps to mitigate the effects of the geomagnetically induced currents, in many cases based on prior experiences with GMDs.

Reference: Geomagnetic Disturbances Analysis

Disturbances by Analysis Category

Operating Guide	Incident Number											
	1	2	3	4	5	6	7	8	9	10	11	12
Guide I — Systems Control												
I.D. — Interchange Scheduling			√								√	
Guide II — System Security												
II.A. — Real Power (MW) Supply						√						
II.C. — Transmission Operation		√										
II.D. — Relay Coordination	√						√		√	√		√
II.E. — Monitoring Interchange Parameters		√	√							√		
II.F. — Information Exchange — Systems Conditions		√	√									
II.G. — Disturbance Reporting		√										
Guide III — Emergency Operations												
III.A. — Insufficient Generation Capacity						√						
III.D. — System Restoration		√	√									
III.E. — Emergency Information Exchange												√
Guide IV. — Operating Personnel												
IV.A. — Responsibility and Authority						√						
Guide V — Operations Planning												
V.A. — Operations Planning — Normal Operations								√			√	
V.B. — Planning for Emergency Conditions		√	√									
V.E. — Operations Planning — System Restoration									√			
Guide VI. — Telecommunications												
VI.A. — Facilities							√					
Planning Policies and Guides								√	√			

Incident

1. Pacific AC Intertie Separation — March 4, 1991
2. Illinois/Indiana Ice Storm — March 12-13, 1991
3. American Electric Power, Allegheny Power System, PJM Interconnection Severe Thunderstorms — April 9, 1991
4. Virginia Power Hayfield Substation Pole Fire — April 13, 1991
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10. SE Idaho/SW Wyoming Outage — September 12, 1991
11. Iowa/Minnesota/Nebraska Ice Storm — October 31, 1991
12. Pacific AC Intertie Separation — November 17, 1991

1. Pacific AC Intertie Separation — March 4, 1991

Summary

A Pacific AC Intertie (PACI) separation occurred on March 4, 1991, at 0508 PST when gusting winds caused a tower to collapse on the Round Mountain-Table Mountain No. 2 500 kV line 30 miles north of Table Mountain Substation.

High-speed reclosing of the Round Mountain-Table Mountain No. 2 500 kV line was not successful due to the permanent fault caused by the tower failure. On the reclose attempt, the Table Mountain-Vaca Dixon 500 kV line relayed by a false trip of the current phase comparison relays.

Prior to the disturbance, Table Mountain circuit breaker 812 was out of service for a scheduled overhaul. With this breaker out of service, the false operation of the Table Mountain-Vaca Dixon line open-ended the Round Mountain-Table Mountain No. 1 500 kV line, causing a total PACI separation between Round Mountain and Table Mountain Substations. See Figures 1 and 2.

The planned remedial action then successfully initiated a total separation of the PACI, tripping 700 MW of pump load by Pacific Gas and Electric Company (PG&E) and 85 MW of pump load by the California Department of Water Resources. System frequency dropped to 59.55 Hz, causing 208 MW of additional interruptible load shedding in the PG&E area by underfrequency relays. The planned remedial action tripped the following transmission lines to separate the WSCC system into two islands following a total intertie separation:

Malin-Round Mountain 500 kV No. 1 and No. 2
Four Corners-Pinto 345 kV
Four Corners-Shiprock 230 kV
Red Butte-Harry Allen 345 kV
San Juan-Shiprock 345 kV
San Juan-Waterflow 345 kV
Farmington-Gallegos 115 kV
Glen Canyon 230/345 kV separation
Silver Peak-Control 55 kV
California-Summit-Drum 115 kV No. 2
North Truckee-Summit-Drum 115 kV No. 1
Truckee-Summit-Spaulding 55 kV
Weed Junction-Cascade 115 kV (open prior to disturbance)

Immediately following controlled separation, the frequency in the Pacific Northwest and Rocky Mountain Regions rose to 60.28 Hz. A total of 1,050 MW of Pacific Northwest generation tripped as part of planned remedial action to control system overspeed.

Table 1 — *Sequence of Events— Pacific AC Intertie Separation*

Time	Event
0508	Pacific AC Intertie separates between Round Mountain and Table Mountain
0523	Table Mountain-Vaca Dixon 500 kV line was returned to service
0534	Malin-Round Mountain-Table Mountain No 1 500 kV line returned to service
0542	Malin-Round Mountain No. 1 500 kV line returned to service connecting the two islands
0544	Malin-Round Mountain No. 2 500 kV line returned to service
0609	Four Corners-Pinto 345 kV line returned to service, restoring the WSCC transmission loop
0651	All WSCC transmission restored

During the initial Round Mountain-Table Mountain No. 2 500 kV line operation, the Midway-Vincent No. 3 500 kV line also relayed falsely. The loss of this line had no significant impact on the disturbance. Investigation revealed a faulty card in the phase comparison relay. Prior routine testing did not reveal the problem.

The false trip of the Table Mountain-Vaca Dixon 500 kV line was caused by a bad connection in a multi-conductor plug connector between the phase comparison relay and its communication equipment at Vaca Dixon. This false operation, coupled with the outage of circuit breaker 812 at Table Mountain, caused the total PACI separation.

System Security

Plug connections on the Vaca Dixon relays were repaired. PG&E subsequently investigated the replacement of the connectors used on this type of relay, and found the cost prohibitive. As an alternative, PG&E is developing a procedure for routinely testing the relay with the connectors left intact. PG&E also recommends more frequent testing of these relays.

Refer to: Guide II.D., Relay Coordination

The bad phase comparison relay logic board at Midway was replaced. PG&E is designing a procedure to detect bad circuit boards during routine testing.

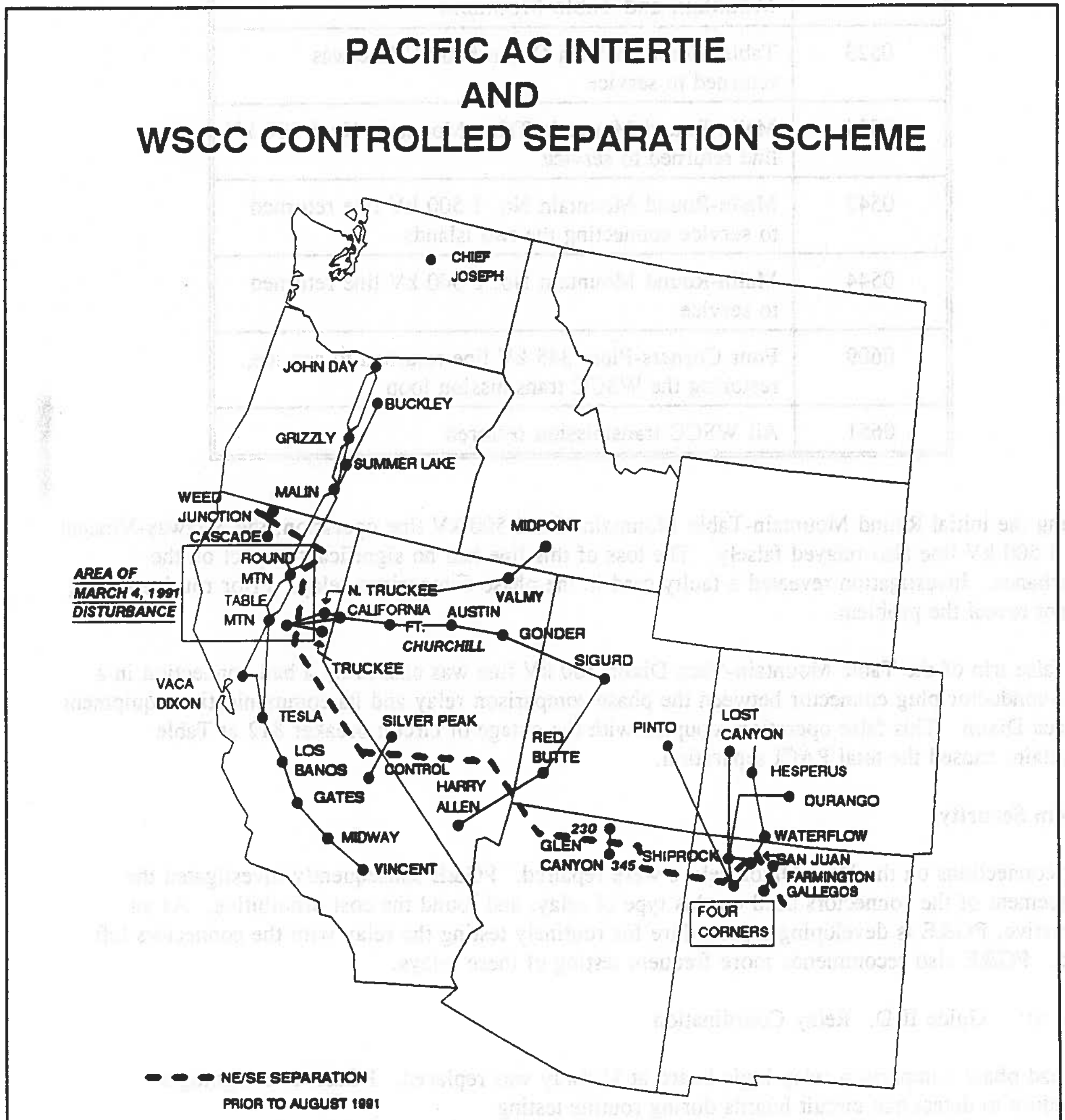


Figure 1 — *Pacific AC Intertie and WSCC Controlled Separation Scheme*

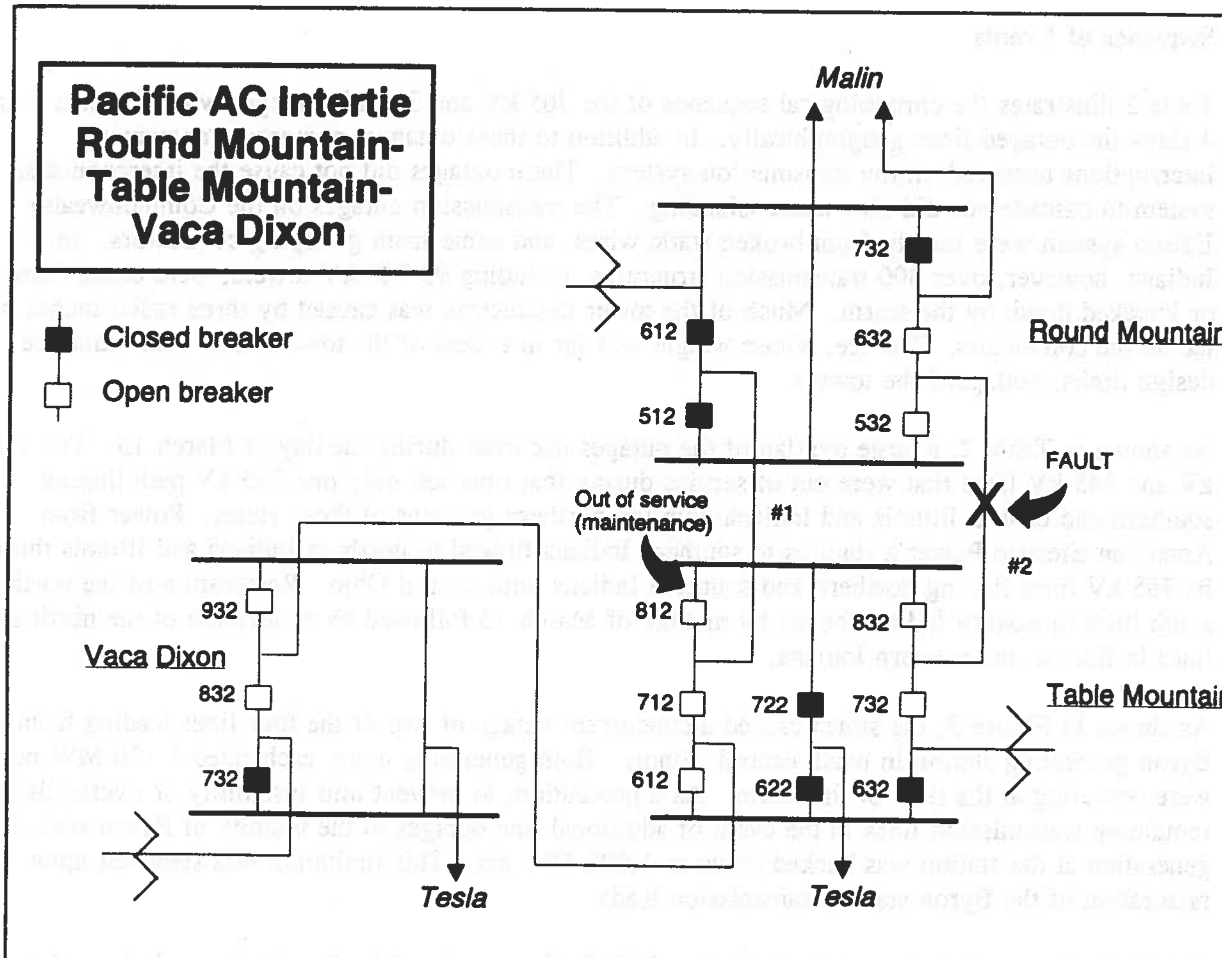


Figure 2 — *Pacific AC Intertie Separation — Detail of Round Mountain, Table Mountain, and Vaca Dixon Substations*

2. Illinois/Indiana Ice Storm — March 12-13, 1991

Summary

On March 12-13, 1991, northern Illinois and northern and central Indiana were hit by a severe ice storm. This storm was accompanied by 30-35 mile per hour winds and affected customers of Commonwealth Edison Company, Indiana Michigan Power Company (an operating company of the American Electric Power System), and PSI Energy, Inc. The ice storm caused outages of three 765 kV, 21 345 kV, five 230 kV, 27 138 kV, and 28 69 kV lines. Other lines became isolated due to open breakers.

Sequence of Events

Table 2 illustrates the chronological sequence of the 765 kV and 345 kV outages while Figures 3 and 4 show the outaged lines geographically. In addition to these outages, numerous momentary interruptions occurred on the transmission system. These outages did not cause the interconnected system to cascade nor did they cause islanding. The transmission outages on the Commonwealth Edison system were mostly from broken static wires, and some from galloping conductors. In Indiana, however, over 300 transmission structures, including 95 765 kV towers, were either damaged or knocked down by the storm. Much of the tower destruction was caused by three radial inches of ice on the conductors. The ice, whose weight was far in excess of the towers' one inch radial ice design limits, collapsed the towers.

As shown in Table 2, a large overlap of the outages occurred during the day of March 13. The 765 kV and 345 kV lines that were out of service during that time left only one 345 kV path linking southern and central Illinois and Indiana with the northern portions of those states. Power from American Electric Power's stations in southern Indiana flowed to northern Indiana and Illinois through its 765 kV lines linking northern and southern Indiana with central Ohio. Restoration of the north-south lines in eastern Indiana began by midday of March 13 followed by restoration of the north-south lines in Illinois and western Indiana.

As shown in Figure 3, the storm caused a concurrent outage of two of the four lines leading from Byron generating station in north central Illinois. Both generating units, each rated 1,120 MW net, were operating at the time of the storm. As a precaution, to prevent unit instability or overloads on remaining transmission lines in the event of additional line outages in the vicinity of Byron station, generation at the station was backed down to 1,900 MW net. This limitation was removed upon restoration of the Byron station transmission leads.

The storm also caused the outage of the two 345 kV lines north of the Pontiac transmission substation. These lines are important to the flow of power from Commonwealth Edison's Kincaid Station, rated at 1,108 MW net. To prevent a possible transmission overload if one of the two remaining Kincaid lines tripped, Commonwealth Edison backed down generation at Kincaid to 560 MW net.

Shortly after the 95 towers were taken down by the storm on the Greentown-Jefferson 765 kV line (Figure 5), Cook Unit #2, 1,100 MW, tripped, although the specific cause remains unknown. A 765 kV shunt inductor at Dumont failed due to an internal fault. The failure of this inductor delayed energizing of the Dumont-Greentown 765 kV line until May 22, 1991.

Approximately 500,000 customers lost power during various times during the storm. The majority of these interruptions were due to distribution damage. However, transmission outages caused loss of power to Kokomo, Indiana and vicinity for nearly nine hours; to the Kankakee, Illinois area for approximately ten hours; and to the Bradley, Illinois area for over six hours. Heavy snow on top of the ice made access to some of these areas for restoration very difficult.

System Security

The ice storm affected transmission lines of three different utilities in two different Regional Councils. The systems shared outage information using established procedures. However, because of the extent of the outages, wider and earlier dissemination of this information could have helped other utilities to plan better for contingency situations that might have occurred.

Refer to: Guide II.C., System Security — Transmission Operation
Guide II.F., System Security — Information Exchange — System Conditions
Guide II.G., System Security — Disturbance Reporting

The large number of alarms overloaded the SCADA computer at Commonwealth Edison's Southern Division power supply office in a manner similar to the tornado incident reported in the *1990 System Disturbances* report. This overload caused slow computer response, which delayed the isolation, switching, and restoration of outaged lines. However, no load was lost due to these short delays. A new local SCADA system with increased memory was on order at the time of the ice storm and was installed in January 1992.

Refer to: Guide II.E., System Security — Monitoring Interconnection Parameters

Real power output of generating units at two stations was reduced to prevent overloads or instability in anticipation of additional outages. These reductions were based on previous studies anticipating such outages.

Refer to: Guide II.C., System Security — Transmission Operation

Emergency Operations

Restoration of the transmission system was planned by prioritizing the needs of the bulk power system. Commonwealth Edison concentrated on restoring outlets to its generating plants to remove generation limitations imposed by the outages. The plan also concentrated on early restoration of north-south 345 kV lines. The ECAR utilities quickly restored the north-south 345 kV lines in eastern Indiana. The western Indiana lines as well as the 765 kV lines in Indiana had downed structures and restoration took three to five months, respectively.

Refer to: Guide III.D., Emergency Operations — System Restoration

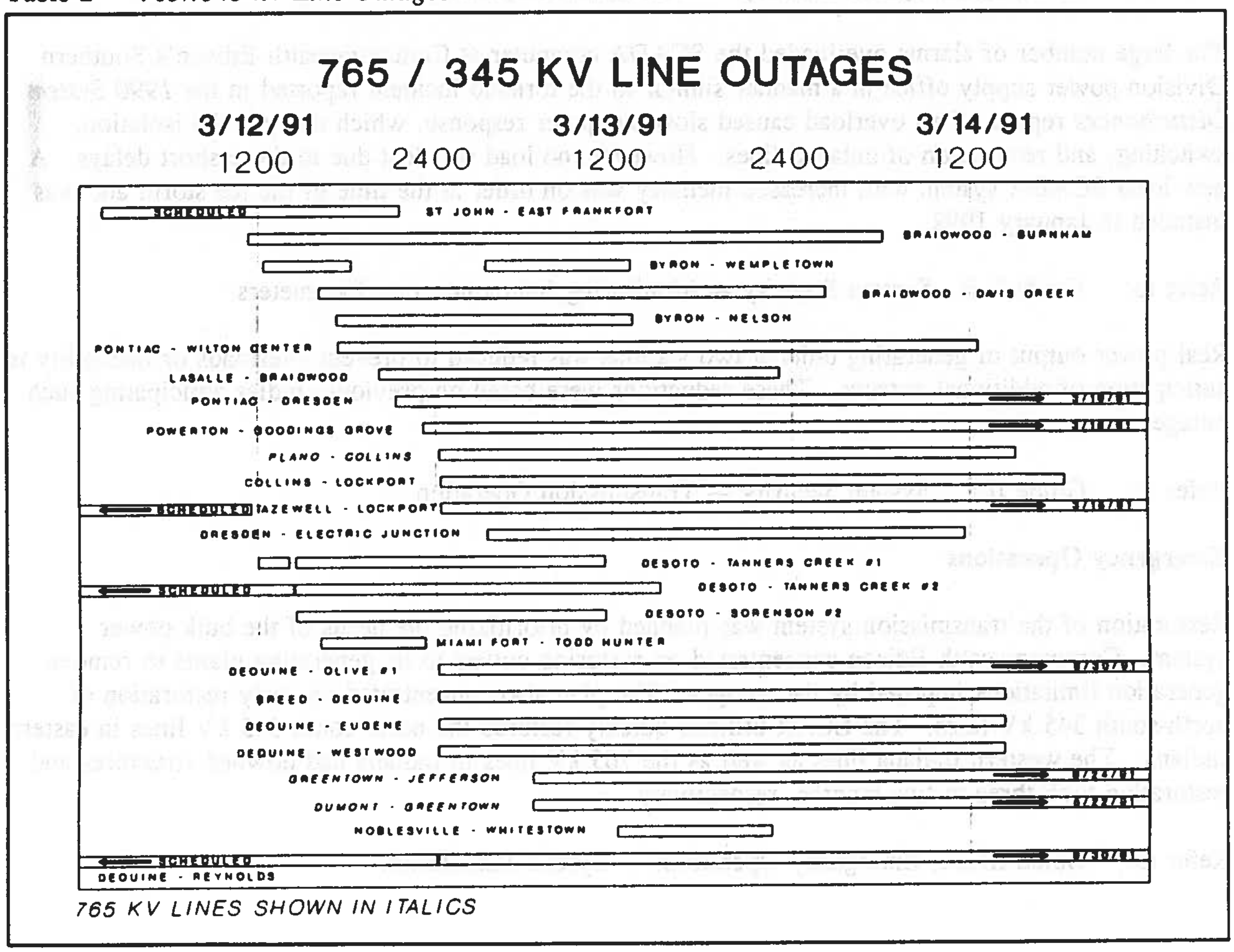
Operations Planning

This disturbance was extreme and severely stressed the bulk electric system. The actual outages far exceeded any of the MAIN or ECAR reliability criteria. However, the event occurred during lighter load conditions and the systems held together without cascading. Only customers affected by substation isolation or distribution system damage from the storm suffered outages due to this major disturbance.

Subsequent to the ice storm, the 345 kV outages in western Indiana and the 765 kV outage limited the electricity transfer capability from ECAR to MAIN. The affected utilities and Regions were aware of the transfer limitations, and the utilities operated the interconnected system reliably in accordance with NERC, MAIN, and ECAR guidelines.

Refer to: Guide V.B., Operations Planning — Planning for Emergency Conditions

Table 2 — *765//345 kV Line Outages*



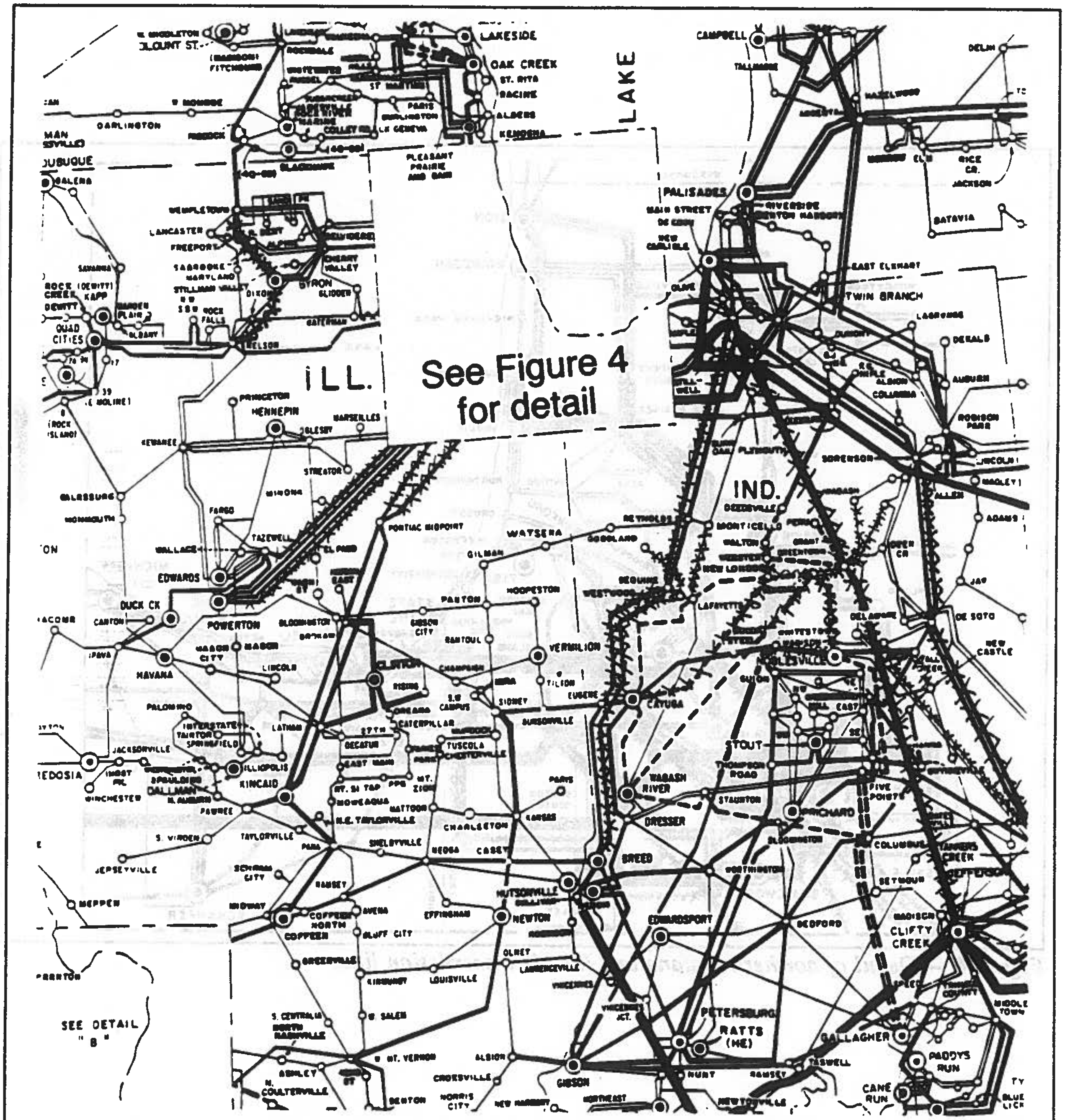


Figure 3 — *Transmission lines affected by March 12-13, 1991 Ice Storm*

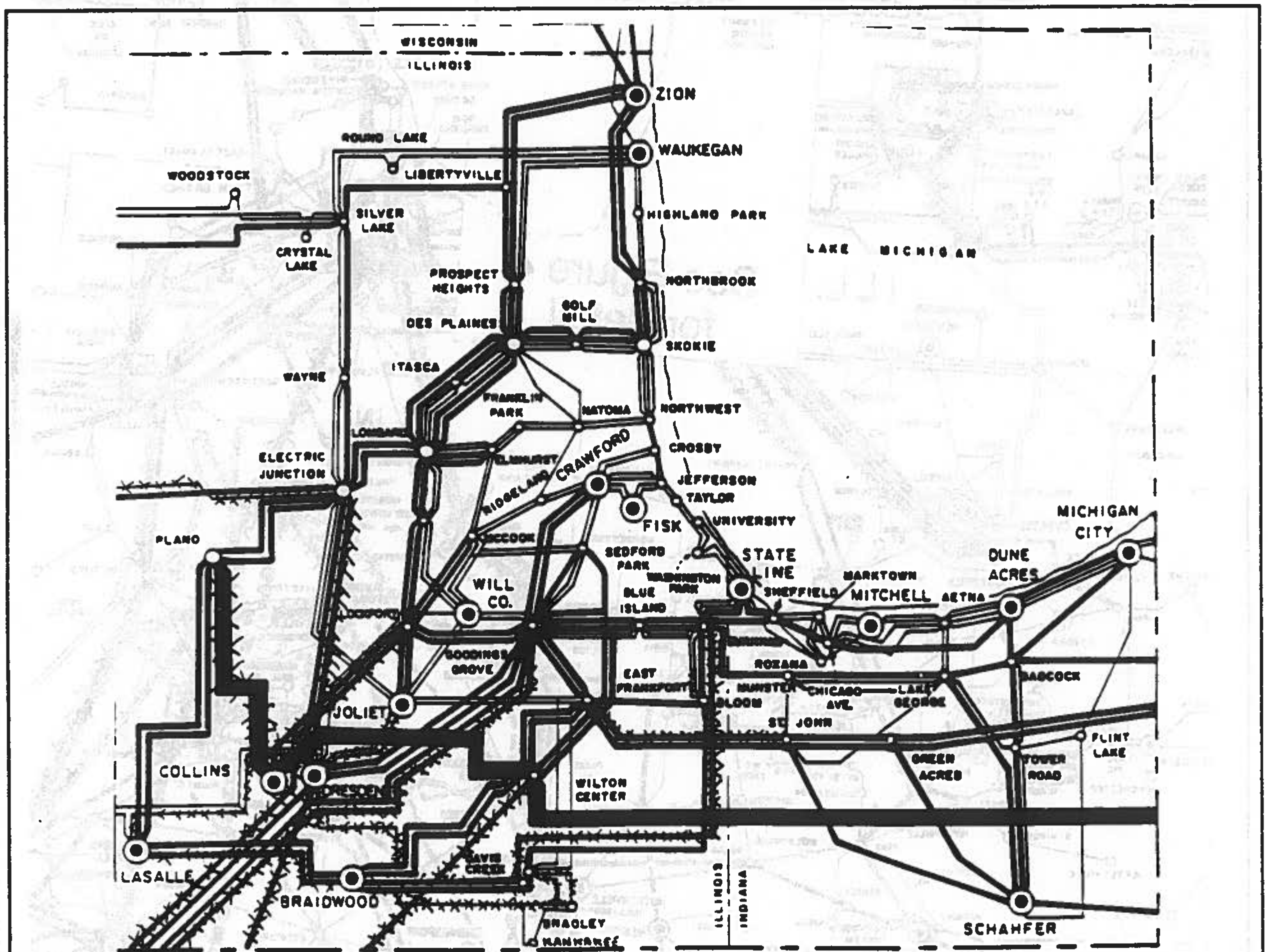


Figure 4 — *Detail of northern Indiana and Illinois transmission lines*

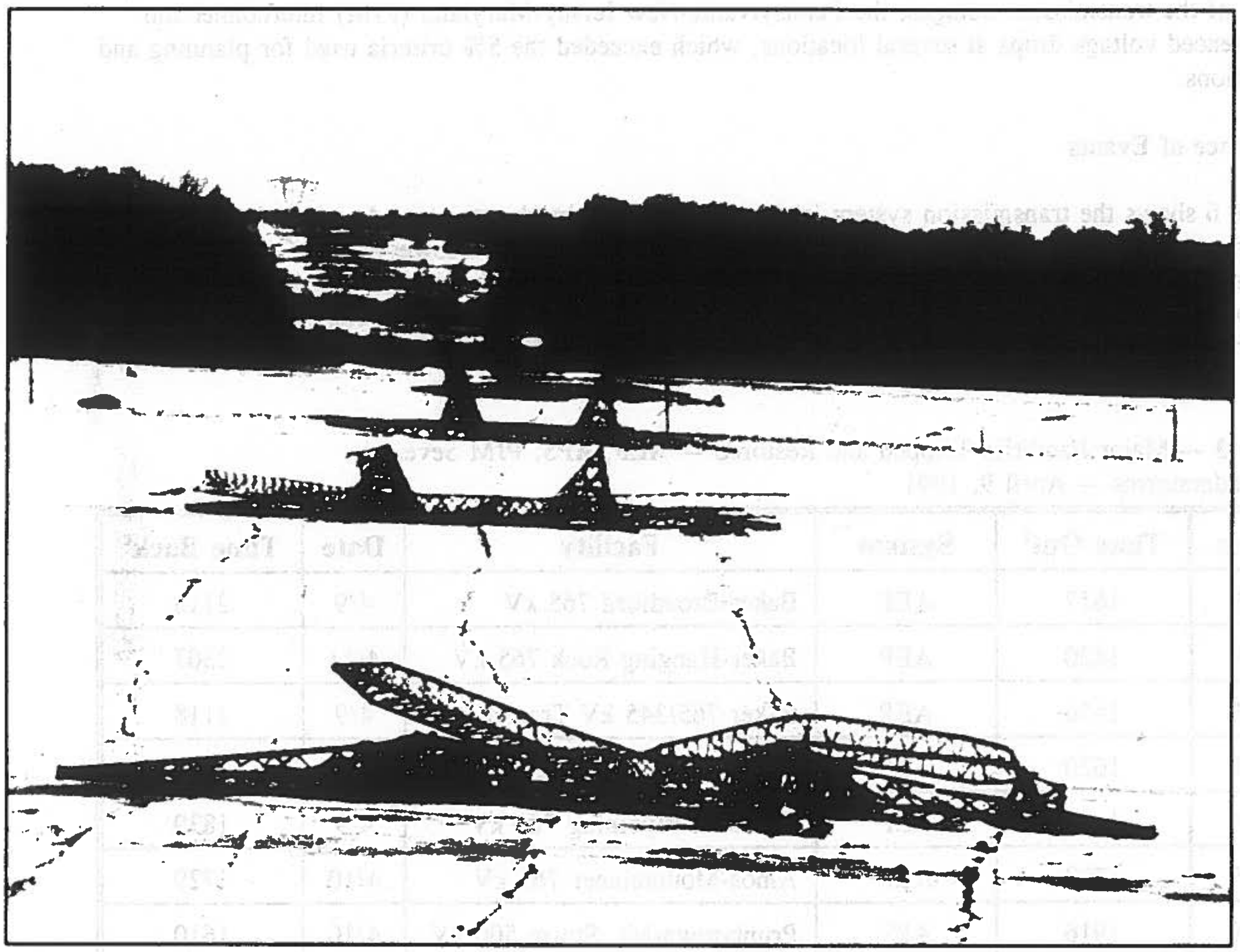


Figure 5 — *Portion of Collapsed Dumont-Greentown-Jefferson line*

3. American Electric Power, Allegheny Power System, PJM Interconnection Severe Thunderstorms — April 9, 1991

Summary

On Tuesday evening, April 9, 1991, thunderstorms with high winds, heavy rain, hail, and tornadoes raced through the ECAR Region, primarily in Kentucky and West Virginia, causing numerous EHV line tripouts and some permanent damage from high winds. Five 765 kV lines in the American Electric Power (AEP) System and two 500 kV lines in the Allegheny Power System (APS) tripped during the course of the evening. Eight APS 138 kV lines also tripped out, with three 138 kV lines remaining out of service. More than 100,000 Appalachian Power Company (APCo) distribution customers were out, but no customers were out due to bulk transmission outages. However, as a result of the transmission outages, the Pennsylvania-New Jersey-Maryland (PJM) Interconnection experienced voltage drops at several locations, which exceeded the 5% criteria used for planning and operations.

Sequence of Events

Figure 6 shows the transmission system in the areas affected by the storms. At one point, all five 765 kV lines and the Baker 765/345 kV transformer were out of service. However, the Culloden-Wyoming 765 kV line was restored before the 500 kV line outages occurred. The AEP system redispatched generation to maintain transmission facilities within acceptable limits. It should be noted that the Amos 765/345 kV, 1,500 MVA transformer failure on January 21 contributed to the increased EHV loadings.

Table 3 — Major Facilities Tripped and Restored — AEP, APS, PJM Severe Thunderstorms — April 9, 1991

Date	Time Out[1]	System	Facility	Date	Time Back[1]
4/9	1617	AEP	Baker-Broadford 765 kV	4/9	2118
4/9	1620	AEP	Baker-Hanging Rock 765 kV	4/11	2307
4/9	1620	AEP	Baker 765/345 kV Transformer	4/9	2118
4/9	1620	AEP	Baker-Culloden 765 kV	4/9	2118
4/9	1654	AEP	Culloden-Wyoming 765 kV	4/9	1839
4/9	1702	AEP	Amos-Mountaineer 765 kV	4/10	1729
4/9	1916	APS	Pruntytown-Mt. Storm 500 kV	4/10	1610
4/9	1942	APS	Black Oak-Bedington 500 kV	4/16	

[1]Central Daylight Time

At one point, the storm had interrupted enough EHV lines that the East Coast was nearly severed from the Midwest from mid-Tennessee to the Great Lakes. Only the 500 kV lines at Keystone, the 345 kV interconnection between Cleveland Electric Illuminating Company and the PJM Interconnection, and the Kanawha-Matt Funk 345 kV line (AEP) remained in service. Out of the four remaining EHV lines spanning the storm path, two Keystone lines were over their continuous thermal ratings for a period until transfers were curtailed.

The loss of the AEP 765 kV lines caused APS to reduce transfers at 1630 CDT. Line loadings on the Pruntytown-Mt. Storm and Black Oak-Bedington 500 kV lines increased significantly with the loss of the Baker-Broadford 765 kV line. Following the loss of additional AEP lines, APS further reduced transfers at 1710 CDT. By 1805, line loadings eased and APS ended the higher transfer restrictions.

The most significant impact to PJM was the loss of the Pruntytown-Mt. Storm and Black Oak-Bedington 500 kV lines within about 1/2 hour of each other. Loss of these two lines interrupted the major transfer paths from APS into southern PJM. The Conemaugh 500 kV bus voltage dropped 6.1%, as shown on Graph 1. Also, voltage drops of 5 to 5.5% were recorded at Keystone and Juniata 500 kV stations. For a short period, the Keystone-Yukon 500 kV line was overloaded (1,876 versus 1,766 MVA rating).

This was the time (1945-2010) that APS and PJM were in a critical situation. The Yukon-Keystone and Cabot-Keystone 500 kV lines were loaded in excess of their continuous ratings and PJM experienced voltage drops in excess of 5% at Keystone, Conemaugh, and Juniata. Loss of any 500 kV line out of Keystone or Conemaugh could have resulted in system voltage instability and subsequent loss of load.

Systems Control

In PJM, Conemaugh Units #1 and #2 were operating in a balanced mode prior to the disturbance, but the Unit #1 voltage regulator was being operated in the manual mode due to a problem requiring maintenance that could only be performed during a unit outage. The Conemaugh station operator had to make an immediate decision of what action to take when confronted by the weather conditions of April 9. Within seconds, the Unit #2 field voltage and field current were in alarm, the 500 kV system voltage had dropped by 30 kV, and the Unit #2 reactive output was exceeding its capability. Because the Conemaugh Unit #1 voltage regulator was being operated in the manual mode, this unit had no response to the disturbance. It would have been very easy for the operator to protect Unit #2 by reducing its field excitation, eliminating the alarms, and ignoring the 500 kV system voltage. However, the Conemaugh operator's first response was not to lower the Unit #2 field voltage, but to manually increase the Unit #1 field voltage in an attempt to stabilize the 500 kV voltage. This provided more reactive supply to the 500 kV system. It also drove Unit #1 field current above its rating. The operator, therefore, allowed both of the Conemaugh units to exceed their field ratings for several minutes. The quick and correct actions of the Conemaugh operator may not have been typical without training and experience. The operator on duty was one of the more experienced at the plant, and had a keen sense of the relationship between the 500 kV voltage, machine reactive output, and field excitation. The operator also had the patience to wait for the 500 kV system voltage to restore itself to normal, and did not react hastily to the alarms as long as no plant equipment was being jeopardized. As a result of the experience gained from this disturbance, a training program was initiated to inform the other Conemaugh station personnel of the correct operating procedures to follow when a large 500 kV voltage drop occurs. In addition, the field alarm limits at the Conemaugh and Keystone stations were reviewed and operating memos issued to confirm that these units can run continuously at their rated field amperes, and even higher for shorter periods.

Refer to: Guide I.D., Systems Control — Voltage Control

System Security

PJM was not completely aware of the extent of the situation for two reasons: First, PJM did not have an automated communications system to receive rapid, automatic information concerning the remote outages as they occurred. Such information would have helped the PJM operators be more fully prepared for subsequent contingencies. It is impractical to expect manual methods of data exchange to be adequate under emergency conditions. Second, PJM did not have the capability to automatically monitor some of the transmission lines outside its boundaries, which can have significant impacts on PJM if these lines trip.

APS and PJM personnel reviewed the incident. In addition, the incident was reviewed at the Operating Representatives of Northeast Systems (ORNS) meeting in April. The meeting evaluated the performance of each control area and made recommendations to correct deficiencies found. The recommendations have been or will be implemented.

Refer to: Guide II.E., System Security — Monitoring Interconnection Parameters
Guide II.F., System Security — Information Exchange — System Conditions

Emergency Operations

All systems promptly acted to maintain a secure transmission system. PJM was purchasing heavily from the west when the APS circuits tripped. Upon loss of the first APS circuit, PJM significantly reduced economy purchases. Upon loss of the second circuit PJM:

- Reduced economy transfers by 3,000 MW.
- Loaded all spinning reserve.
- Started combustion turbines.
- Issued a manual load dump alert.

AEP cut generation supplying PJM economy energy at plants that minimized loadings on the transmission system. AEP also purchased energy from Duke Power Company and Carolina Power & Light Company to provide pumping energy at pumped storage projects to make them fully available the next day for transmission support.

APS shifted generation to the Bath County pumped storage hydro facility (at AEP's request).

Refer to: Guide III.D., Emergency Operations — System Restoration

Operations Planning

This disturbance was extreme and severely stressed the bulk electric system. The outages far exceeded any of the ECAR or MAAC reliability criteria. However, the event occurred during lighter load conditions and the system held together without cascading. Only customers affected by substation isolation or distribution system damage from the storm suffered outages due to this major disturbance.

An after-the-fact analysis by the PJM Operations Planning Branch indicated that an off-line load flow analysis would have accurately predicted the large voltage drop, which occurred for the second 500 kV line outage, had the analysis been made before the incident occurred. The outage that occurred was the worst second contingency that could have occurred. The same analysis also indicated voltage drops in excess of 11% could have occurred if both 500 kV lines had tripped simultaneously. Therefore, the prompt action by the operators following the first outage was very beneficial.

An after-the-fact analysis by AEP indicated possible loss of load due to severe overloads and low voltages in APCo if:

1) AEP internal load was 17,000 MW (actual was about 12,000 MW), or

2) AEP internal load was 15,000 MW, but Culloden-Wyoming had not been restored before the two APS 500 kV circuits tripped, or

3) ECAR sales to the east/southeast were 6,000 MW (actual were about 4,600 MW), and Culloden-Wyoming had not been restored before the two APS 500 kV circuits tripped.

Refer to: Guide V.B., Operations Planning — Planning for Emergency Conditions

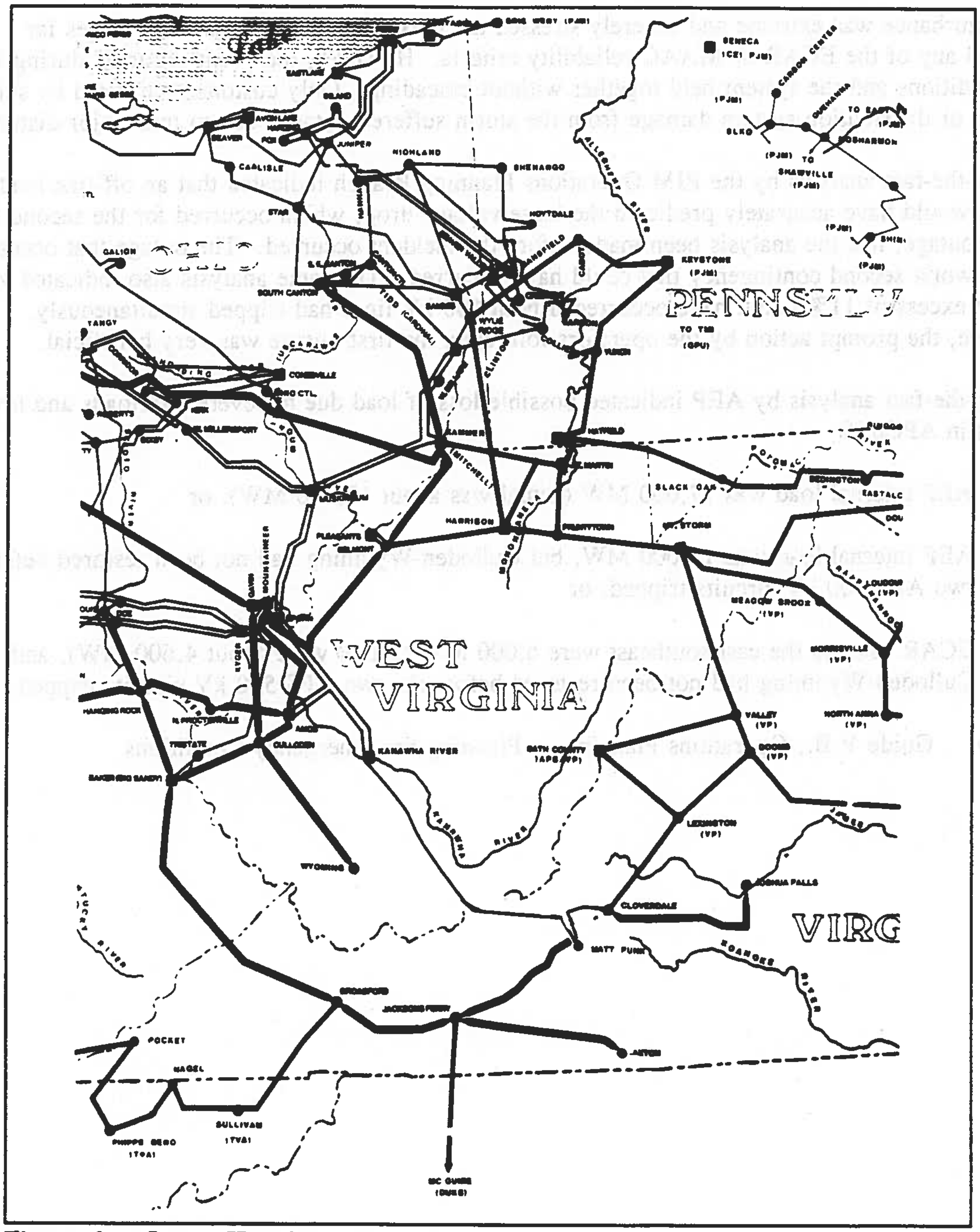
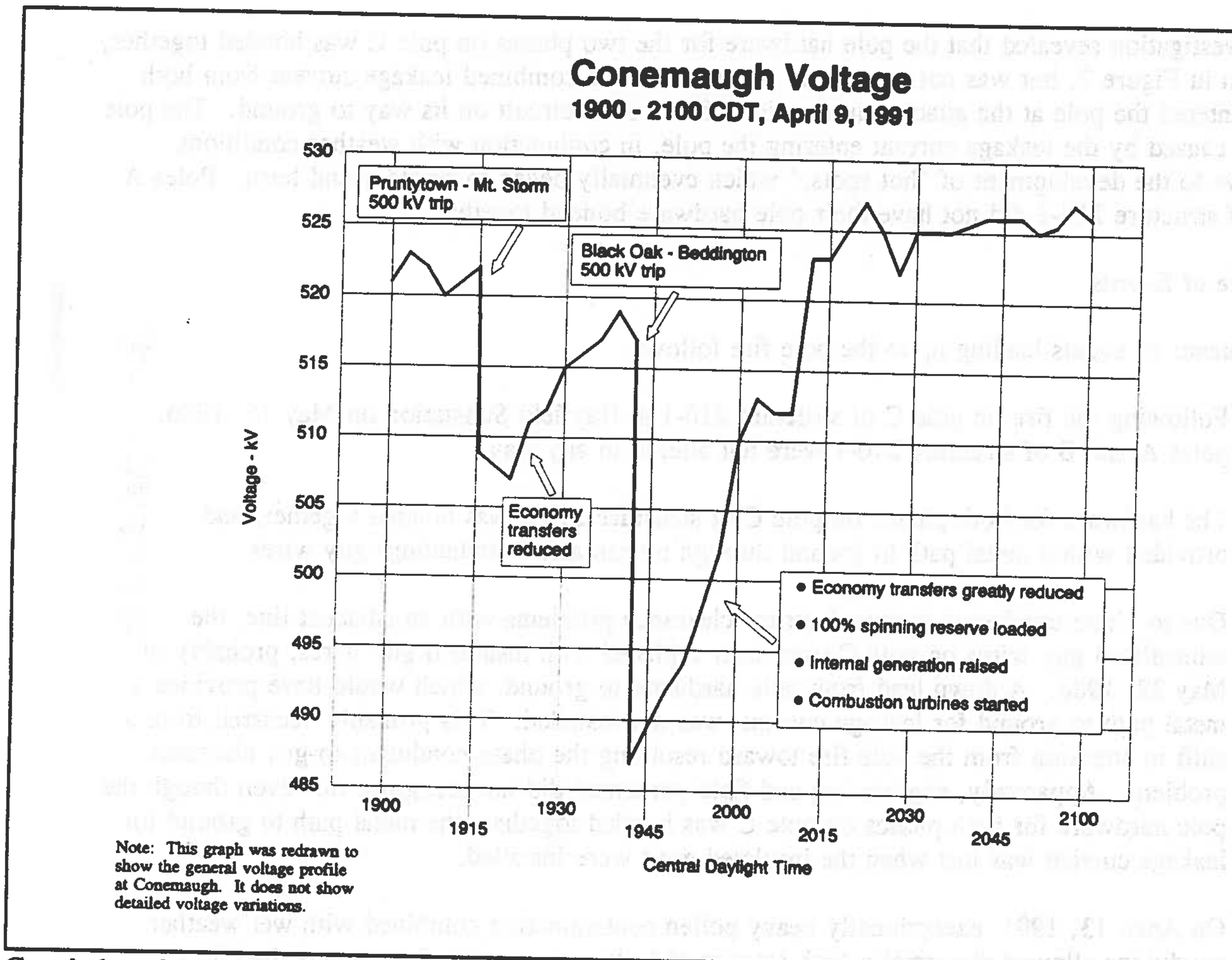


Figure 6 — *Severe Thunderstorms — April 9, 1991*

3. American Electric Power, Allegheny Power System, PJM Interconnection Severe Thunderstorms — April 9, 1991



Graph 1 — *Voltage at Conemaugh Substation*

4. Virginia Power Hayfield Substation Pole Fire — April 13, 1991

Summary

On April 13, 1991 at approximately 2230 EDT, a pole fire burned through pole C of structure 210-1 on the 230 kV Hayfield-Van Dorn line 210. This double-circuit structure is a three-pole double dead-end angle that also carries the 230 kV Glebe-Ox line 248 and is the first structure outside Hayfield Substation. The fire burned through pole C at the attachment location of the lower circuit, line 210, which allowed phase C of line 210 to fall into the 230 kV bus inside Hayfield Substation. The same pole of structure 210-1 burned five years ago on May 15, 1986 at the same location.

Field investigation revealed that the pole hardware for the two phases on pole C was bonded together, as shown in Figure 7, but was not grounded. As a result, the combined leakage current from both phases entered the pole at the attachment location of the lower circuit on its way to ground. The pole fire was caused by the leakage current entering the pole, in conjunction with weather conditions conducive to the development of "hot spots," which eventually began to smolder and burn. Poles A and B of structure 210-1 did not have their pole hardware bonded together.

Sequence of Events

The sequence of events leading up to the pole fire follows:

1. Following the fire on pole C of structure 210-1 at Hayfield Substation on May 15, 1986, poles A and B of structure 210-1 were not altered in any way.

2. The hardware for both phases on pole C of structure 210-1 was bonded together, and provided with a metal path to ground through uninsulated (conducting) guy wires.

3. Due to phase conductor-to-guy electrical clearance problems with an adjacent line, the uninsulated guy wires on pole C were later replaced with insulated guy wires, probably on May 22, 1986. A down lead from pole hardware to ground, which would have provided a metal path to ground for leakage current, was not installed. This probably occurred from a shift in attention from the pole fire toward resolving the phase conductor-to-guy clearance problem. Apparently, engineering and field personnel did not recognize that even though the pole hardware for both phases on pole C was bonded together, the metal path to ground for leakage current was lost when the insulated guys were installed.

4. On April 13, 1991, exceptionally heavy pollen contamination combined with wet weather conditions allowed abnormally high amount of leakage current to flow across the phase conductor insulators. As the combined leakage current from lines 210 and 248 flowed to ground through the wood pole, a "hot spot" developed where the leakage current entered the wood pole. The "hot spot" began to smolder and burn, eventually burning completely through the pole.

As a result of this pole fire and subsequent outage to a large number of customers, Virginia Power took the following corrective actions:

1. The hardware on each pole of structure 210-1 was bonded together and provided with a metal connection to ground through the use of a down lead and pole ground. (This reflects current structure design that provides leakage current a direct path to ground.)

2. To further ensure future reliability, the three wood poles in structure 210-1 were then replaced with concrete poles.

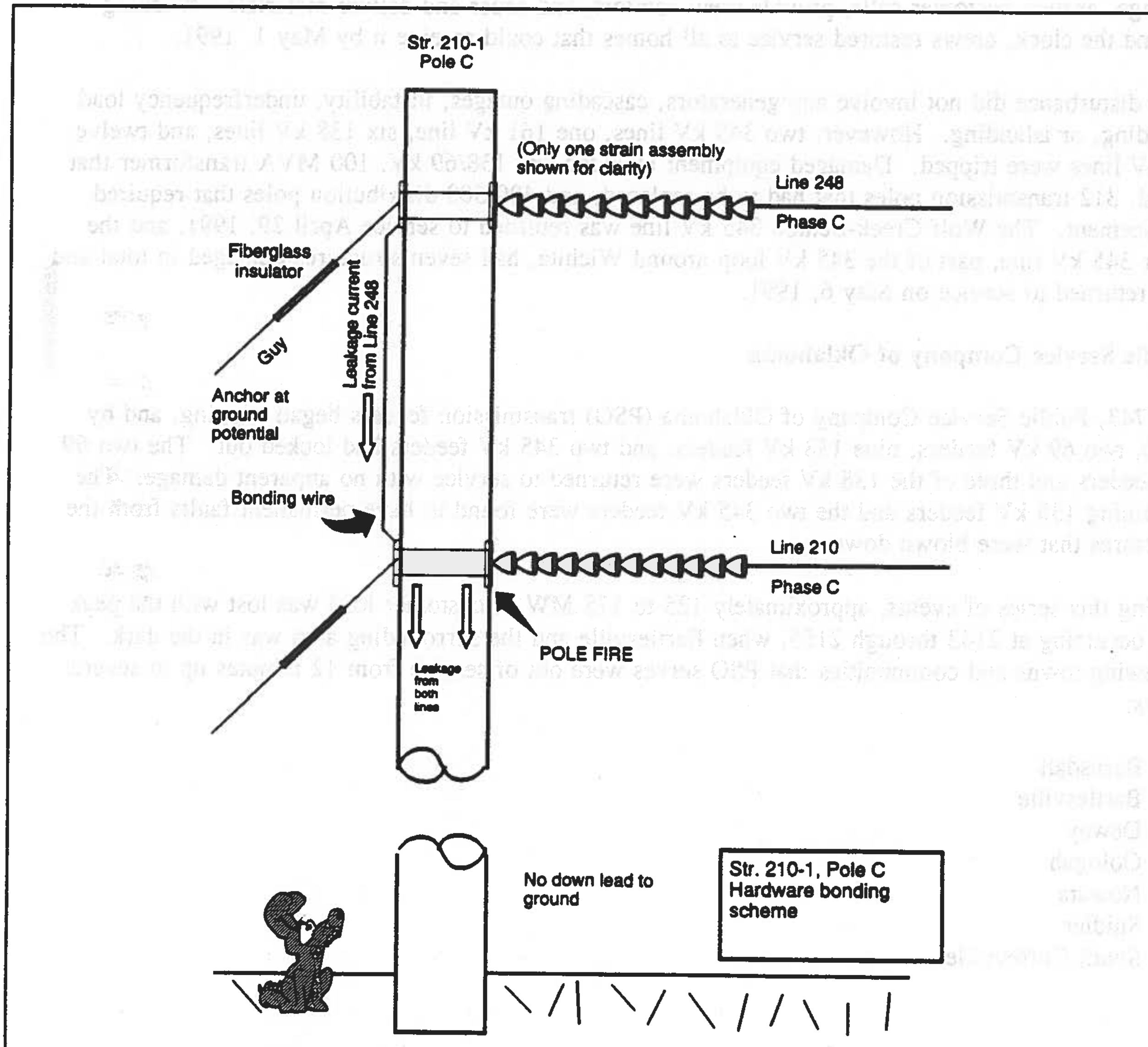


Figure 7 — *Pole C at Hayfield Substation*

5. Kansas Gas and Electric Company and Public Service Company of Oklahoma Tornadoes — April 26, 1991

Friday evening, April 26, 1991, a series of tornadoes and severe weather developed in North Central Oklahoma and moved toward the northeast. (Figure 8)

Kansas Gas and Electric Company

Several tornadoes passed through the western half of Kansas Gas and Electric Company's (KG&E) service territory, destroying transmission and distribution lines. Electric service was disrupted to 65,000 customers representing approximately 300 MW of load. Initial repairs restored service to more than 20,000 customers within a few hours. By early April 27, 1991, a work force of more than 675 — including 227 from neighboring utilities and contractors — had been assembled to repair damage, answer customer calls, provide crew comfort, and order and deliver materials. Working around the clock, crews restored service to all homes that could receive it by May 1, 1991.

This disturbance did not involve any generators, cascading outages, instability, underfrequency load shedding, or islanding. However, two 345 kV lines, one 161 kV line, six 138 kV lines, and twelve 69 kV lines were tripped. Damaged equipment included one 138/69 kV, 100 MVA transformer that failed, 312 transmission poles that had to be replaced, and 400-500 distribution poles that required replacement. The Wolf Creek-Benton 345 kV line was returned to service April 29, 1991, and the other 345 kV line, part of the 345 kV loop around Wichita, had seven structures damaged in total and was returned to service on May 6, 1991.

Public Service Company of Oklahoma

At 1743, Public Service Company of Oklahoma (PSO) transmission feeders began tripping, and by 2150, two 69 kV feeders, nine 138 kV feeders, and two 345 kV feeders had locked out. The two 69 kV feeders and three of the 138 kV feeders were returned to service with no apparent damage. The remaining 138 kV feeders and the two 345 kV feeders were found to have permanent faults from the structures that were blown down.

During this series of events, approximately 125 to 175 MW of customer load was lost with the peak loss occurring at 2143 through 2155, when Bartlesville and the surrounding area was in the dark. The following towns and communities that PSO serves were out of service from 12 minutes up to several hours:

Barnsdall
Bartlesville
Dewey
Oologah
Nowata
Snidler
South Coffeyville

The following PSO transmission customer loads were also out of service from 12 minutes to several hours:

KAMO Electric Cooperative

Hula
North Bartlesville
Rice Creek
Watova
West Pawhuska

Oklahoma Municipal Power Authority

Copan South
Hominy
Pawhuska

The transmission system in the Northern Division remained severely weakened for several hours with the Bartlesville area being connected to only one 138 kV feeder, the interconnection with KG&E (feeder 81-826). Feeder 81-843, which locked out at 2107 with seven single-pole structures on the ground near Skiatook Dam, was returned to service at 0320 on April 28, providing a second 138 kV source to the Bartlesville area and securing this area of the KG&E system. By the afternoon of April 29, all customers were returned to service, although three 138 kV feeders and two 345 kV feeders remained out of service. Feeder 81-816 from Bartlesville SE to Northeastern Station was returned to normal at 1256 on April 30. Two 138 kV feeders and the two 345 kV feeders remained out of service.

Table 4 — *Feeders returned to service*

Date	Event
May 10	345 kV feeder 90-908 (Northeastern Station to KG&E Neosho)
May 12	138 kV feeder 81-815 (Nowata to Northeastern Station)
June 10	345 kV feeder 90-909 and 138 kV feeder 81-822 (Northeastern Station to Tulsa North)

With the return of these feeders, the PSO transmission system was restored from all known damage caused by the April tornadoes.

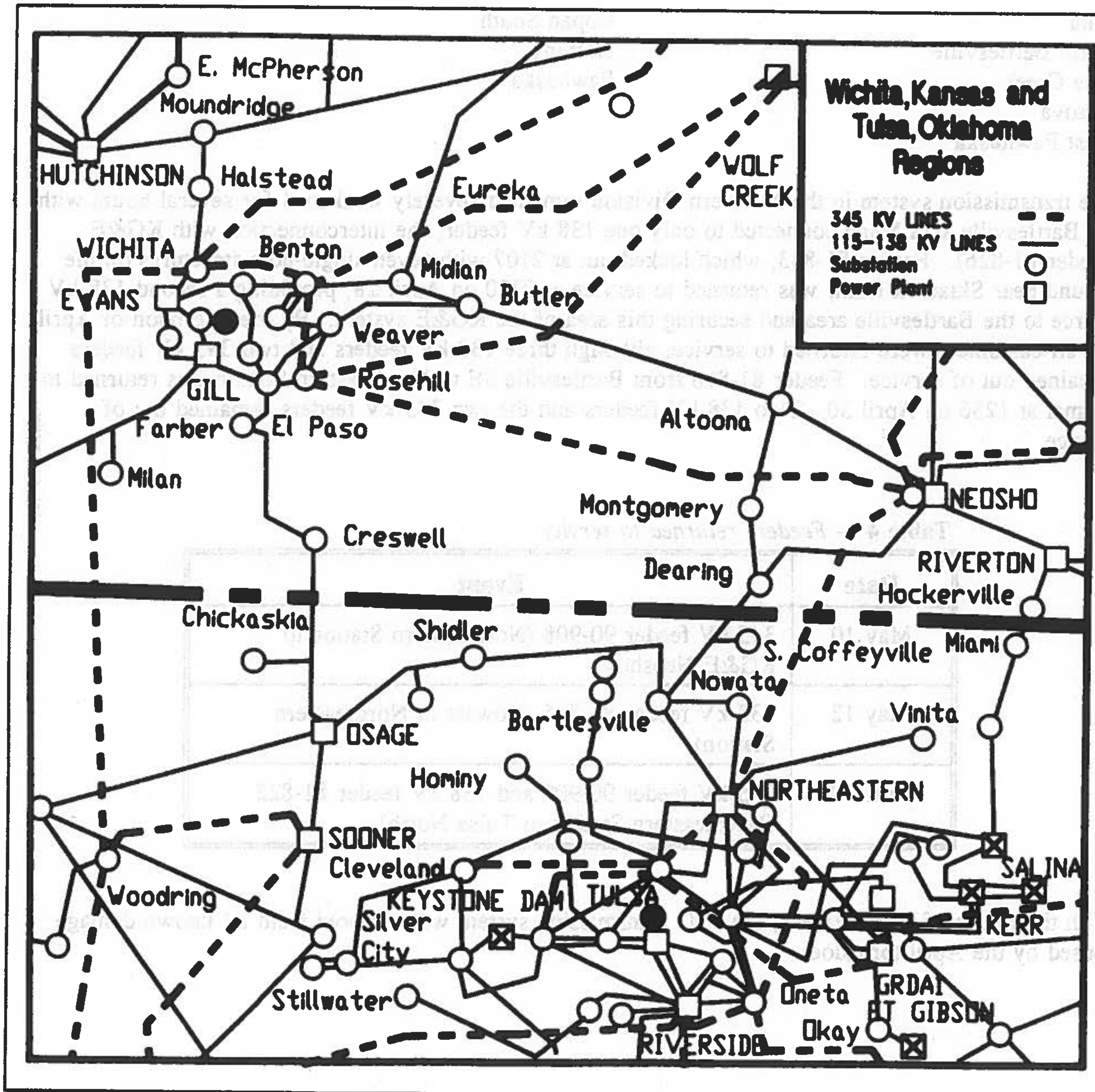


Figure 8 — *Detail of transmission system in Wichita, Kansas, and Tulsa, Oklahoma areas*

6. Florida Capacity Alert — April 29, 1991

Summary

A Statewide Generating Capacity Advisory/Alert was declared effective at 1600 EDT on Monday, April 29, 1991. The Statewide Alert was terminated at 2000 EDT on the same day. The Statewide Advisory remained in effect until 2400 EDT, Wednesday, May 1, 1991. This condition resulted from unseasonably hot, humid weather while periodic generation maintenance was taking place.

Florida Power Corporation Public Appeal

During this period, Florida Power Corporation (FPC) declared a systemwide Phase I Capacity Alert effective at 1530 EDT, Wednesday, May 1, 1991 through the evening peak at 2000 EDT. In response to the Statewide Capacity Advisory/Alert and the systemwide Phase I Capacity Alert, FPC issued public conservation appeals for those periods.

Florida Power & Light Company Public Appeal

On the morning of April 29, 1991, Florida Power & Light Company (FPL) was faced with a projected generation capacity of 13,020 MW to meet a forecasted, 1700-1800 EDT peak demand of 13,200 MW. A further assessment indicated that the entire state would be short of operating reserves.

Sequence of Events

Recognizing the potential for a capacity shortage, FPL's Power Supply Department began implementing pre-established plans to meet such contingencies. They started to prepare schedules for residential load management, commercial and industrial load control, and the notification of FPL's commercial representatives to instruct customers with large curtailable demand to reduce consumption during the forecasted peak hours. They also secured any purchase power that was available.

Additionally, on a state level, the Florida Electric Power Coordinating Group (FCG) declared an "alert" condition per capacity emergency procedures established after the generation shortage of December 1989. This notified appropriate governmental agencies, including the Governor, that customer load might have to be curtailed if a contingency occurred during the peak. It also asked the Governor to declare a Capacity Alert, which resulted in a public appeal for conservation. FPL began its public appeal at 1000 EDT, requesting voluntary conservation during the peak hours of 1400-1900 EDT.

At 1201 EDT, FPL's Martin #2 unit tripped, leaving only 100 MW of on-line reserve with the demand climbing rapidly. Although used earlier than anticipated, FPL was able to keep up with the demand by activating its load management and commercial load control programs. These programs were in effect four hours for residential customers and six hours for commercial and curtailable customers.

The Martin #2 unit returned to service at 1534 EDT, which enabled FPL to serve an actual peak demand for the day of 12,718 MW. The public appeal is estimated to have reduced the demand by 300 MW.

Comparison to Previous Capacity Shortage

In contrast to the capacity shortage of December 1989, no firm customer load was curtailed. The corrective actions and lessons learned following the 1989 incident were effective. Among these were:

1. The implementation of a statewide capacity assessment plan
2. Implementation of procedures for declaring capacity shortages
3. Earlier, improved use of the media to inform the public and enlist support for conservation
4. Increased installation of residential load control
5. Greatly improved peaking reliability of FPL's fossil generation

Communication of Public Appeal

FPL appealed for conservation through its Corporate Communications Department. Based on needs identified after the capacity shortage of 1989, the Corporate Communications Department implemented a fax list to contact all major media groups in FPL's service territory. Through this process, approximately 100 newspapers, radio and television stations, and key governmental agencies were sent information releases and updates on the status of the power system including the request for conservation. This fax list enhanced the speed and scope of information distribution.

System Security

Capacity assessment: The statewide capacity assessment procedure itself worked well. Some discrepancies existed in how reserves were counted and actual amounts.

Refer to: Guide II.A., System Security — Real Power (MW) Supply

Emergency Operations

There was a misinterpretation by some utilities that they could not violate operating reserve criteria by selling reserves to help another utility. The FCG Operating Committee has clarified this issue.

Refer to: Guide III.A., Emergency Operations — Insufficient Generation Capacity

Power Supply

The sudden loss of the Martin Unit #2 demonstrated the need to have load control programs directly available to dispatch personnel. Although the commercial departments achieved excellent response, sudden changes such as the Martin trip require immediate steps.

Refer to: Guide II.A., System Security — Real Power (MW) Supply

7. Four Corners Units 3, 4, and 5 Trip — July 16, 1991

Summary

On July 16, 1991, at 1547 MST, a thunderstorm caused the Four Corners-San Juan 345 kV line to trip. The unplanned operation of two breaker failure relay schemes at Four Corners resulted in the loss of local transmission, 1,459 MW of generation, and 14 MW of firm load at Four Corners Substation (Figure 9). Loss of the Four Corners generation made it necessary to manually trip 103 MW of interruptible load to meet spinning reserve requirements. Loss of station power affected telephone circuits and SCADA indications, which caused delays in restoration.

System frequency ranged from 59.83 Hz to 60.1 Hz during the disturbance. The Four Corners-San Juan 345 kV line was restored at 1554 MST. All interruptible load was restored at 1650 MST and all firm load was restored at 1722 MST. All transmission was restored by 2159 MST.

Operation of breaker failure lockout schemes on both the 230 kV and 345 kV sides of the Four Corners No. 8 345/230 kV transformer resulted in de-energizing the east 345 kV bus, the south 230 kV bus, and the 4,160 volt reserve auxiliary bus. The breaker failure relay on the 230 kV transformer breaker (FC822) operated because the time delay element in the lockout scheme was temporarily removed during a rewiring project. The breaker failure relay on the 345 kV transformer breaker (FC432) operated because the dc trip switches were inadvertently left open and tagged in the breaker control cabinet during previous work.

When the south 230 kV bus cleared, the No. 2 230/69 kV transformer was de-energized, dropping 7 MW of Navajo Tribal Utility Authority firm load and 7 MW of Utah International Mine firm load. Four Corners Unit #3 also tripped when this bus cleared.

Four Corners Unit #4 was operating with a temporary exciter fed from the reserve auxiliary 4,160 volt bus. When this bus was de-energized, the unit lost excitation and tripped off line.

The Four Corners Unit #5 anti-motoring relay tripped the unit 21 seconds after the reserve auxiliary bus de-energized. The control systems for Four Corners Units #4 and #5 were also being operated from the reserve auxiliary bus. The unit control systems are normally fed from an uninterruptible power supply (UPS). However, the UPS was out of service for repairs.

All generator unit RTUs are powered from Units #3-5 auxiliaries and were lost when these units tripped. Transducers for many analog inputs to switchyard RTUs are powered from station power. These analog values went bad after loss of the No. 2 230/69 kV transformer resulted in loss of station power. However, switchyard status and control were maintained with switchyard RTUs.

Power to the Private Branch Exchange (PBX) telephone system was lost when the No. 2 230/69 kV transformer was de-energized. There is no power backup to the PBX, and all dial telephone service was dropped. The direct ring-down telephones between the Energy Control Center and the plant control room were routed through the PBX and also were affected.

System Security

Most of the outages for this disturbance were caused by the unplanned operation of two breaker failure relays. After reviewing this disturbance, Arizona Public Service Company (AZPS) concluded that "...the impact of temporary modifications on the FC822 breaker failure relay was not clear at the time the modifications were made." Also, the open dc trip switches in breaker FC432 was not an acceptable operating configuration.

Refer to: Guide II.D., Relay Coordination, Recommendation 1.7

Protection system applications, settings, and coordination should be reviewed periodically, and whenever major changes in generating resources, transmission load, or operating conditions are anticipated. AZPS recommended that:

1. Procedures for temporary relay configuration changes should be reviewed for possible revision. AZPS has implemented a procedure so that all proposed temporary relay configurations will be submitted to engineering for review.

2. Positions of dc trip switches and switch name labels should be field checked. A field check revealed several problems with switch labeling, which were resolved.

Refer to: Guide VI, Telecommunications

Failure of communication equipment delayed the restoration of firm load and the Four Corners switchyard. AZPS recommended that:

1. Direct ring-down telephones between the Energy Control Center and the plant control room should be separated from the local PBX switch.

2. Plant RTUs should be powered from an uninterruptible power supply.

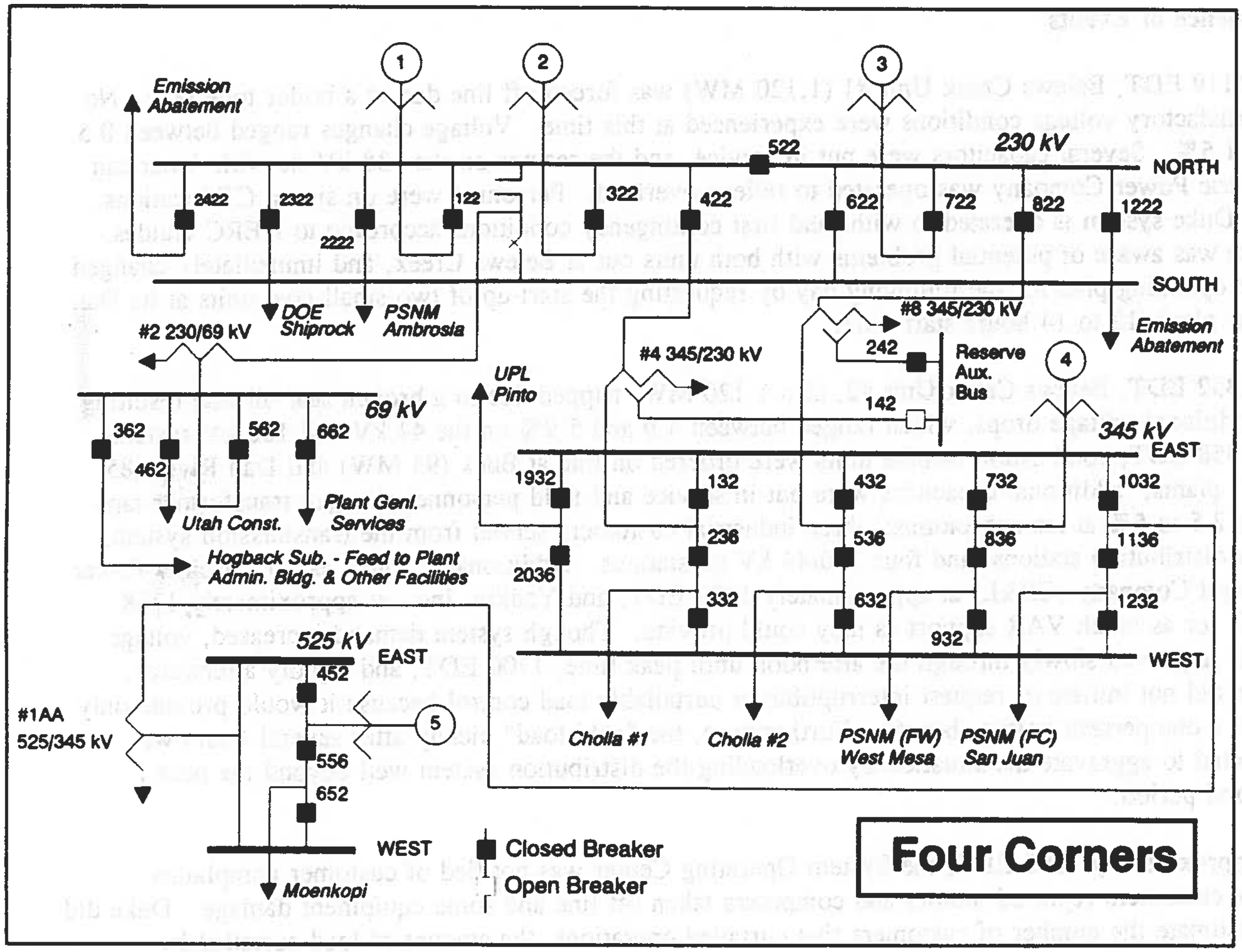


Figure 9 — *Four Corners Substation*

8. Duke Power Company Belews Plant Outage — July 24, 1991

Summary

On July 24, 1991 beginning at 1352 EDT, loss of the second Belews Creek unit (two-unit plant) resulted in an approximate 8% voltage drop in portions of the northern 30% of the Duke Power Company transmission system (Figure 10). The total affected area of North Carolina included Hickory, Winston-Salem, Greensboro, and Durham, involving approximately 490,000 customers, which represent approximately 4,400 MW of load. Winston-Salem and Greensboro were the more significantly affected areas, and the voltage data given below refers specifically to these areas.

Sequence of Events

At 1119 EDT, Belews Creek Unit #1 (1,120 MW) was forced off line due to a boiler tube leak. No unsatisfactory voltage conditions were experienced at this time. Voltage changes ranged between 0.5 and 1.5%. Several capacitors were put in service, and the reactor on the 138 kV tie with American Electric Power Company was operated to relieve overload. Personnel were on site at CT locations. The Duke system is operated to withstand first contingency conditions according to NERC Guides. Duke was aware of potential problems with both units out at Belews Creek, and immediately changed their operating plan for the following day by requesting the start-up of two small coal units at its Dan River plant (12 to 14 hours start time).

At 1352 EDT, Belews Creek Unit #2, also 1,120 MW, tripped due to a broken seal oil line resulting in additional voltage drops, which ranged between 4.9 and 5.9% on the 44 kV and 100 kV systems. At 1358 EDT, combustion turbine units were ordered on line at Buck (93 MW) and Dan River (85 MW) plants; additional capacitors were put in service and field personnel changed transformer taps from 2.5 to 5% at ten substations: three industrial customers served from the transmission system, three distribution stations, and four 100/44 kV tie stations. Additionally, Duke asked Carolina Power & Light Company (CP&L) at approximately 1500 EDT, and Yadkin, Inc., at approximately 1738 EDT, for as much VAR support as they could provide. Though system demand increased, voltage levels improved slowly through the afternoon until peak time, 1700 EDT, and rapidly afterwards. Duke did not initiate or request interruptible or curtailable load control because it would provide only about a one percent voltage benefit. Furthermore, the "cold load" pickup after several hours was expected to aggravate the situation by overloading the distribution system well beyond the peak demand period.

At approximately 1500 EDT, the System Operating Center was notified of customer complaints. Some customers reported motors and computers taken off line and some equipment damage. Duke did not estimate the number of customers that curtailed operations, the amount of load curtailed by customers, or the extent of damage to customer facilities.

A hypothetical next-most-significant contingency would likely have been the loss of one of the 230 kV CP&L tie circuits (Roxboro B or W). This loss would impose an additional voltage drop of approximately 5% in these areas and could not be tolerated without load relief. It should be noted, however, that even with this next contingency, problems would be localized and no transmission overloading would result. No threat of cascading outage or voltage collapse would be imposed on the interconnected transmission network.

System Security

Loss of two 1,120 MW units at one generation plant site resulted in a transmission system voltage drop of approximately 8%.

Refer to: NERC Planning Guides — To the extent practicable, a balanced relationship is maintained among bulk electric system elements in terms of size of load, size of generating units and plants, and strength of interconnections. Application of the Guide includes the avoidance of:

- Excessive concentration of generation capacity in one unit, at one location, or in one area;
- Excessive dependence on any single transmission circuit, tower line, right-of-way, or transmission switching station; and
- Excessive burdens on neighboring systems.

Loss of 1,100 MVAR reactive power resources resulted in reliance on neighboring systems for VAR support.

Refer to: NERC Planning Guides — Reactive power resources are provided which are sufficient for system voltage control under normal and contingency conditions, including support for a reasonable level of planned transfers and a reasonable level of emergency power transfers.

Operations Planning

Consider the efforts of EPRI and others with regard to both on-line and off-line voltage prediction.

Refer to: Guide V.A., Operations Planning — Normal Operations

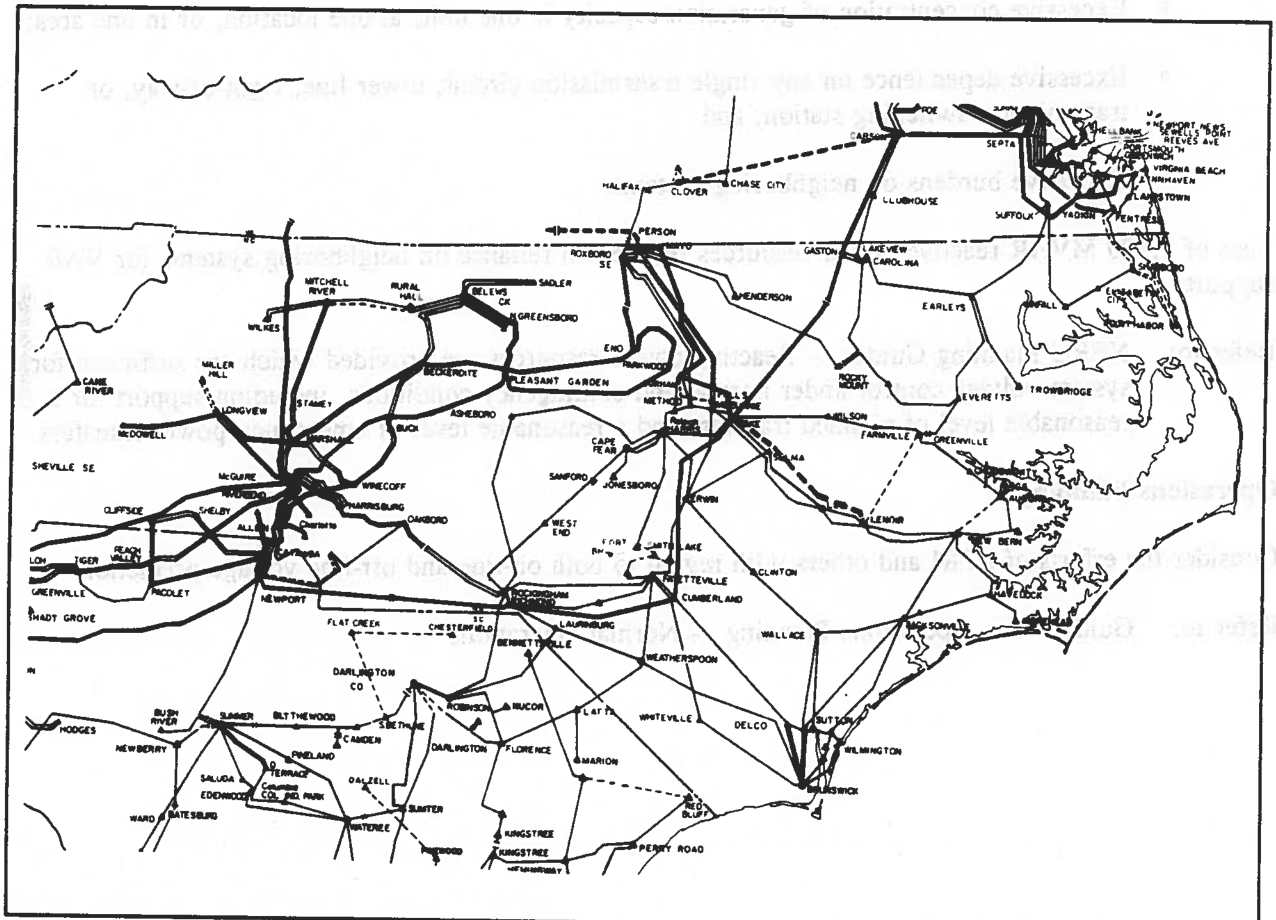


Figure 10 — *Transmission system in North Carolina*

9. Tennessee Valley Authority South Nashville 161 kV Substation Fault — August 8, 1991

Summary

South Nashville 161 kV substation is in the center of the Tennessee Valley Authority (TVA) transmission system and serves a portion of the municipal load of Nashville, Tennessee (Figure 11). On the afternoon of August 8, 1991, a thunderstorm began moving through the Nashville area. Breaker failure occurred upon removal of three 69 kV capacitor banks that were in service, causing a fault at South Nashville 161 kV substation.

Sequence of Events

At approximately 1613 CDT, the Nashville Electric Service (NES) 69 kV capacitor bank breaker 664 at South Nashville substation failed while attempting to open all three capacitor banks (108 MVAR). The capacitor banks were later found to have several fuses blown and capacitor cans damaged. A target was found on the UP relay for capacitor bank 1. It is surmised that the UP relay on capacitor bank 1 sensed an imbalance and operated to trip breaker 664. When the capacitor bank breaker failed, it should have been isolated by operation of the NES Transformer 2 differential relay. However, the auxiliary trip relay (12HEA11) that the differential relay operates did not trip the high- and low-side breakers for Transformer 2 to isolate the faulted breaker. It was later found that the auxiliary trip relay was mechanically bound and had an open operating coil. This relay had been trip-tested six weeks prior to this event. Backup protection systems at surrounding stations finally isolated the faulted breaker after approximately ten seconds.

Operations Planning

This situation led to a severe voltage depression in the Nashville area. Load was lost at several substations due to the low voltage, which allowed backup distance and 13 kV ground relays to operate. TVA lost a total of 280.2 MW of load as a result of this event. NES lost an estimated total of 850 MW of load. TVA loads were restored in 10 to 47 minutes. Some of the NES load was out as long as 2 hours and 39 minutes.

Refer to: Guide V.E., Operations Planning — System Restoration

System Security

The long-time remote clearing times are the result of the relaying philosophy that TVA employed when the South Nashville substation was originally built in the late 1940s or early 1950s. TVA did not use local breaker failure schemes during this period. They began using this scheme when the first 500 kV facilities were built during the mid-1960s. TVA has been upgrading breaker failure protection at its 161 kV substations during the last five years by installing true breaker failure schemes when revisions are scheduled for these stations. This scheme provides fast local fault clearing (12-15 cycles) for a stuck breaker.

Refer to: Guide II.D., System Security — Relay Coordination

Recommendation: In order to limit the effect of protective system failure, relay equipment redundancy and local backup should be considered to minimize load loss and system impact.

9. Tennessee Valley Authority South Nashville 161 kV Substation Fault — August 8, 1991

Refer to: NERC Planning Guides — Protective relaying equipment is provided to minimize the severity and extent of system disturbances and to allow for malfunctions in the protective relay system without undue risk to system reliability.

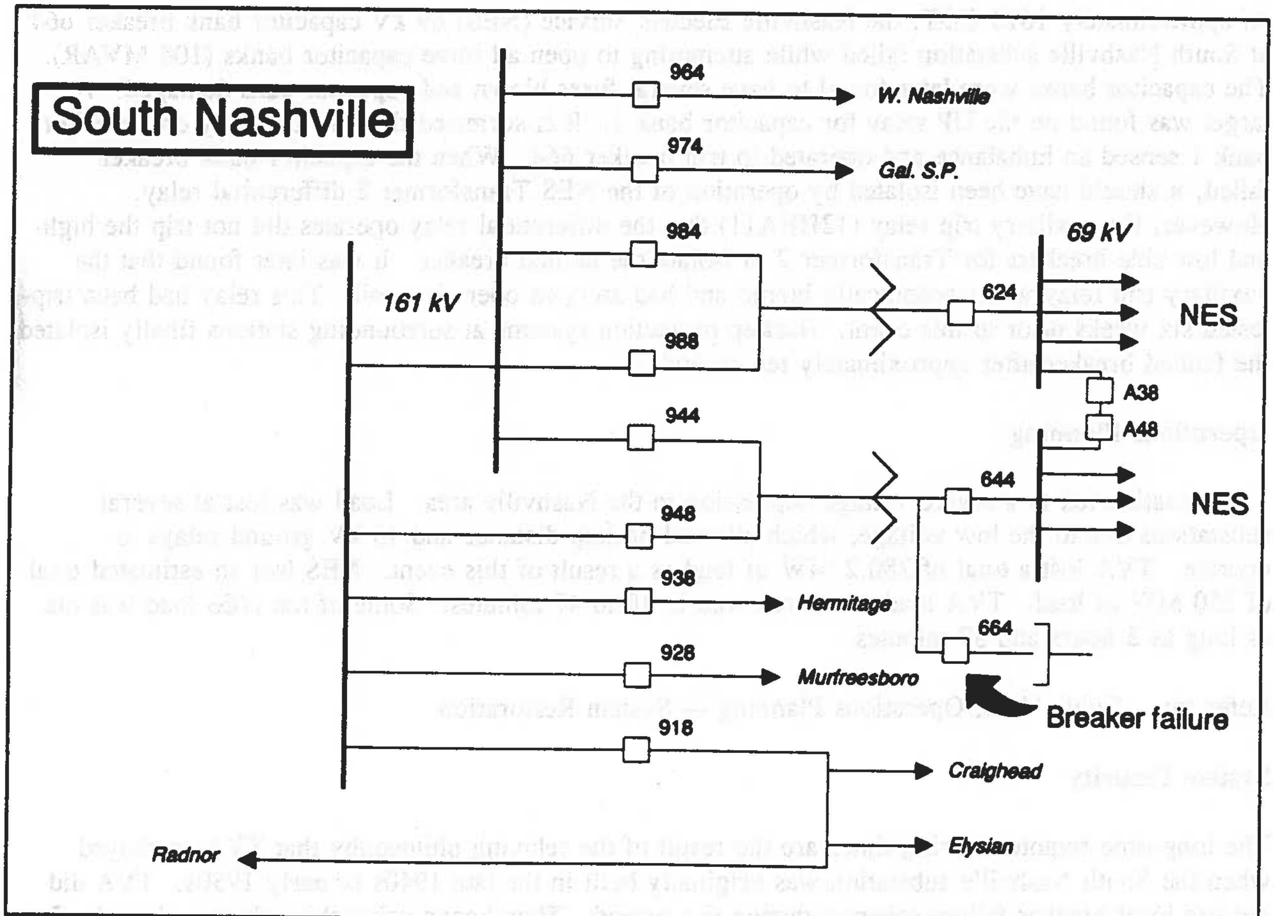


Figure 11 — *South Nashville Substation*

10. SE Idaho/SW Wyoming Outage — September 12, 1991

Summary

At 0205 MDT on September 12, 1991, a system disturbance occurred on the PacifiCorp Electric Operations (PEO) and Idaho Power Company (IPCo) systems, causing the loss of approximately 455 MW of firm load and affecting 50,000 customers in the SE Idaho and SW Wyoming areas. Additionally, 2,243 MW of generation was tripped, causing the system frequency to drop to 59.7 Hz. As a result, Pacific Gas & Electric Company (PG&E) shed 70 MW of industrial load in northern California by underfrequency relaying.

The disturbance began with a single phase-to-ground fault on the Jim Bridger-Kinport 345 kV line, which cleared in two and one-half cycles (Figure 12). Although the Jim Bridger flow to the west was approximately 2,060 MW, the RAS-B (Remedial Action Scheme-B) Generator Tripping Scheme failed to trip generation for loss of this 345 kV line. Approximately 20 cycles later, the Goshen terminal of the Goshen-Kinport 345 kV line relayed open. The Kinport terminal did not open because it failed to receive a transfer trip signal from Goshen. With the two 345 kV lines open and the Jim Bridger plant at full output, the 161 kV transmission lines connected to the Goshen Substation were loaded above their thermal ratings. After a one-minute delay, the Kinport terminal of the Jim Bridger-Kinport 345 kV line reclosed automatically. Due to the heavy system loadings and loss of transmission, the phase angle was measured at approximately 60 degrees across the open breaker at Jim Bridger. Closing of this breaker is blocked at 40 degrees. Procedures were immediately implemented to reduce generation at Jim Bridger to reduce system overloading and low voltage problems. Approximately six minutes after the initial outage, the Goshen-Blackfoot 161 kV line tripped, followed by the Goshen-Grace 161 kV line. At this time, the Jim Bridger plant was still generating over 1,900 MW. At eight minutes after the initial outage, the Antelope 230/116 kV transformer tripped. Next, an out-of-step condition caused the Jim Bridger-Borah 345 kV line to trip. The RAS-B Generator Dropping Scheme then recognized the loss of two 345 kV lines out of Jim Bridger and correctly tripped Jim Bridger generator Units #1 and #2.

Within seconds after tripping of the Jim Bridger-Borah 345 kV line, several 230 kV transmission lines tripped on the out-of-step condition, causing loss of load in the SW Wyoming area.

At this time, Jim Bridger Units #3 and #4 were left generating into a radial system, through the last remaining Bridger-Goshen 345 kV line and through to the 161 kV system serving customers in the SE Idaho area. An exciter overvoltage relay caused Jim Bridger Unit #3 to trip. This also open-ended the Bridger-Goshen 345 kV line because the 345 kV tie breaker to Unit #4 was out of service. At this time, local generation in the Goshen area tripped and customers in the SE Idaho area were interrupted.

The following is a list of load lost, generation tripped, and transmission lines that relayed open during the disturbance.

10. SE Idaho/SW Wyoming Outage — September 12, 1991

Table 5

Load Lost		
Utility	**Type**	**MW**
PEO	Firm	345
IPCo	Firm	30
BPA	Firm	70
Tri-State	Firm	20
PG&E	Interruptible	70

Transmission Relayed Open:

Jim Bridger-Kinport 345 kV line
Goshen-Kinport 345 kV line (Goshen-Terminal end only)
Jim Bridger-Borah 345 kV line
Jim Bridger-Rock Springs 230 kV line
Jim Bridger-Mustang 230 kV line
Jim Bridger-Platte 230 kV line
Goshen-Blackfoot 161 kV line
Goshen-Grace 161 kV line
Jefferson-Dillon-Salmon 161 kV line
Low side breaker to Antelope 230/161 kV transformer

Generation Tripped:

Jim Bridger Units #1, #2, #3, and #4	2,090 MW
PEO QFs	10 MW
IPCo Hydro Units	22 MW
IPCo QFs	29 MW
USBR Palisades Hydro	92 MW
Idaho Falls Hydro	30 MW

Several conclusions were drawn from this event. They are summarized as follows:

1. With prior flows west of Jim Bridger at 2,060 MW, the RAS-B Generator Tripping Scheme should have been armed to trip a Jim Bridger unit following the loss of the Jim Bridger-Kinport 345 kV line. Investigation determined that the flow west signal was 75 MW out of calibration. The system would have remained stable without generation dropping if the Kinport-Goshen 345 kV line had not false-tripped 20 cycles later.

2. There were several relays that did not operate as planned due to incorrect settings, incorrect wiring, or hardware failures:

a. Prior to this event, the SLYP relay at Goshen on the Goshen-Kinport 345 kV line had a card failure that caused a relay element to fail in the closed position. This relay is supervised by a current level detection element. When generator tripping did not occur for the original outage of the Jim Bridger-Kinport 345 kV line, flows on the Goshen-Kinport 345 kV line increased. This satisfied the current level supervision, tripping the Goshen terminal.

b. When the Goshen terminal of the Goshen-Kinport 345 kV line opened, the Kinport terminal failed to receive a transfer trip signal from Goshen and remained closed. If the Kinport Substation would have received a transfer trip signal from the Goshen terminal, the remaining two Kinport 345 kV breakers would have tripped, de-energizing the Kinport 345 kV ring bus. With all four Kinport 345 kV breakers open, the Kinport-Midpoint 345 kV line would have been open-ended. Power flow from the Goshen area through the subtransmission system to the Kinport 345 kV bus would have been inhibited, which would have reduced the loading on the Goshen 161 kV system and provided more time to ramp down the Jim Bridger generation.

c. The Jim Bridger-Rock Springs 230 kV line relays and the Atlantic City-Rock Spring 230 kV line relays tripped the lines in error. Zone 1 and Zone 2 impedance relay elements were designed to be blocked by an SEL-121G relay upon detection of an out-of-step condition. However, the out-of-step block signal was reset by action of another function in the SEL-121G called loss-of-potential logic. Loss-of-potential is used to disable impedance relay elements for loss of ac voltage generally associated with blown fuses. Low voltage during the out-of-step was detected as loss-of-potential. With the block reset, the impedance relay elements were enabled to trip when the voltage recovered.

d. The Borah terminal of the Bridger-Borah 345 kV line tripped for the out-of-step condition. The relays were designed to be blocked for out-of-step conditions, but field inspection revealed that the relays were not set to be blocked.

3. Reduction of generation at the Jim Bridger plant within minutes after the disturbance would have allowed early restoration of the 345 kV transmission system, and would have minimized this disturbance. The 345 kV breakers at Jim Bridger could not be closed due to the large power angle caused by heavy loading across the underlying 230 kV and 161 kV systems.

System Security

This disturbance was initiated by a fault on a single 345 kV line, the failure of a non-redundant Special Protection Scheme, and a relay failure that caused the loss of a second 345 kV line. Telemetry that automatically arms this scheme was out of calibration. System monitoring did not reveal that this scheme was not armed as intended. Although efforts were made to reduce generation following the loss of 345 kV transmission, generation was not reduced quickly enough to allow restoration of the system and avoid further loss of transmission by overload and out-of-step conditions.

Refer to: Guide II.D., Relay Coordination, Recommendation 1.2
Guide II.E., Monitoring Interconnection Parameters

Guide II.D. recommends that protection systems should have redundancy to allow for their normal maintenance and calibration. Guide II.E. requires that monitoring equipment shall be used to bring to the system operators' attention important deviations in operating conditions and to indicate, if appropriate, the need for corrective action. Metering devices have been recalibrated. Redundancy and monitoring is planned for the generator tripping schemes.

Emergency Operations

Guide III.B., Transmission — Overload, Voltage Control requires that systems take all appropriate action up to and including shedding of firm load in order to keep the transmission facilities within acceptable operating limits. Appropriate action was initiated to reduce generation at the Jim Bridger plant. After analysis of this disturbance, it was decided to develop emergency procedures to rapidly reduce generation following a contingency. It is also planned to determine if the allowable closing angle Jim Bridger can be increased to facilitate earlier restoration of the 345 kV transmission system. Currently, the closing of circuit breakers at Jim Bridger is blocked when the phase angle exceeds 40 degrees.

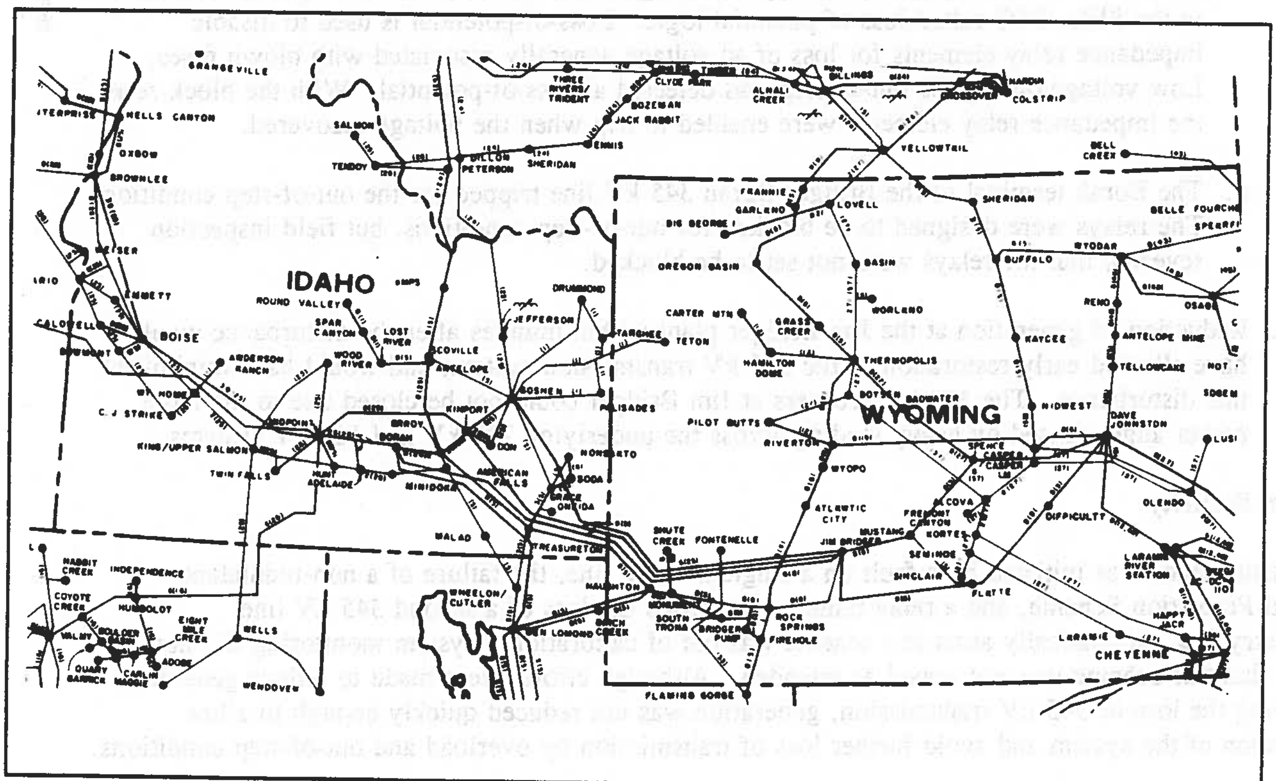


Figure 12 — *Transmission system in Idaho and Wyoming*

11. Iowa/Minnesota/Nebraska Ice Storm — October 31, 1991

Summary

On October 31, 1991, an ice storm hit Nebraska, Iowa, and Minnesota, damaging numerous transmission and distribution lines. The storm caused the outage of four 345 kV and nine 161 kV lines. Due to the weight of two inches of radial ice, more than 500 345 kV structures were knocked down. In parts of Iowa, long stretches of successive, domino-like failures of transmission structures occurred, similar to problems described in the *1990 System Disturbances* report. A section of one line had been replaced in 1990 following damage from an ice storm. Although a portion of this same line went down during this ice storm, the rebuilt section remained intact. It is not certain whether this was due to the added strength of the rebuilt section or if the storm was less severe in the area. Damage to structures in Minnesota was due to ice loading in excess of structure design criteria.

Most of the customer outages resulted from damage to the distribution system, except in the Omaha and the Des Moines areas where a combination of 80 MW to 100 MW of customer load was lost due to transmission outages. Furthermore, the transmission outages forced one utility to institute rotating blackouts in the Fort Dodge, Iowa area to protect its remaining equipment. Because of the extensive damage, full restoration will take many months and reduce interchange to and from the affected utilities. They put operating procedures and cost-sharing agreements in place for running generation to ensure reliability.

System Control

The reduced interchange capability between some areas in MAPP and MAIN requires utilities to ensure that the scheduled interchange does not exceed interchange capability limits.

Refer to: Guide I.D., System Control Interchange Scheduling

Operations Planning

The long-term outage of the transmission lines requires planning engineers to review the operating limitations of the system.

Refer to: Guide V.A., Operations Planning — Normal Operations

12. Pacific AC Intertie Separation — November 17, 1991

Summary

The 500 kV Pacific AC Intertie (PACI) was interrupted on Sunday, November 17, 1991, at approximately 1205 PST, when the Vaca Dixon-Tesla 500 kV line relayed due to a static wire falling into a conductor (Figure 13). Prior to losing this line, the Table Mountain-Tesla 500 kV line was out of service for planned work. Whenever a total separation of the PACI occurs, a Remedial Action Scheme (RAS), also referred to as a Special Protection System, is supposed to initiate controlled separation of the WSCC grid into a northern and a southern island. However, in this disturbance, initiation of the remedial action was delayed approximately three minutes and seven seconds due to a software problem in a PG&E programmable logic controller located in San Francisco. Figure 14 shows the system configuration of the Pacific AC Intertie and the WSCC Controlled Separation Scheme.

Other components of this scheme failed as well, so that even after delayed initiation, controlled separation of the WSCC grid into two islands did not occur as planned. Separation between Malin and Round Mountain did not occur because a current rate-of-change relay did not pick up when the delayed signal arrived. This relay supervises the transfer trip signal from the RAS controller, thus providing security against false initiation of the scheme. Another relay at Midway Substation that provides security failed in the closed position, allowing the delayed signal to be retransmitted to Four Corners. Separation between Waterflow and Hesperus did not occur because of a failed component in the transfer trip equipment. Communications equipment for the separation signal from Four Corners Substation to Sierra Pacific Power Company also failed due to misalignment of a receiver. However, a redundant signal from PG&E operated as planned. Because separation did not occur at Round Mountain and Waterflow, the WSCC grid remained connected.

Due to maintenance that was in progress, PACI line flows from Malin to Round Mountain were low (920 MW), whereas flows on the Vaca Dixon-Tesla 500 kV line were considerably lower. According to operating procedures, loadings were high enough to require controlled separation of the WSCC system into two islands. However, under these light loading conditions, failure of the WSCC grid to separate into two islands did not produce any severe problems. No system load was lost and no out-of-step conditions were experienced, which would have been expected had a failure occurred during higher transmission system loading conditions.

Table 6

Time	Event
1205	Pacific AC Intertie interrupted between Table Mountain-Tesla and Table Mountain-Vaca Dixon
1246	East side of WSCC system around the Four Corners area restored to service
1633	Table Mountain-Tesla 500 kV line restored
1646	Sierra Pacific Power restored all interconnections
2313	Vaca Dixon-Tesla line restored

System Security

Remedial Action Schemes did not operate as intended. A software error in the PG&E RAS programmable logic controller caused the delay in initiating remedial actions. Subsequent analysis showed that a delay would occur for precisely this set of conditions with low loading and an outage of these two lines.

Refer to: Guide II.D., Relay Coordination, Recommendation 2.4

Operation of the complete protection system should be tested under conditions as close to actual operating conditions as possible. Remedial Action Schemes are part of the complete protection scheme. Although PG&E had attempted to thoroughly test the RAS prior to its installation and operation, testing requirements are very complex. Exhaustive and sophisticated test procedures are necessary and may require the use of a simulator. PG&E has modified its test procedures and plans to obtain a simulator with improved testing capabilities.

Although periodic testing of communication channels associated with RAS is coordinated between member systems and occurs several times annually, failures still occurred during this disturbance. Failure of the communications equipment at Waterflow was caused by a failed component. This equipment was tested prior to the disturbance. Communications equipment between Four Corners and Sierra Pacific also failed. This equipment had been tested prior to the disturbance.

The current rate-of-change relays at Round Mountain operated correctly, but then reset before the communication signal arrived. These relays are not designed to stay picked up indefinitely. Delays in communication signals are not common or expected, because redundant channels are provided in the design. A current rate-of-change relay at Midway should have blocked retransmission of the separation signal to Four Corners, but its contacts were stuck in the closed position. Application of such supervision relays meets NERC recommendations that RAS should be designed with inherent security to minimize the probability of an improper operation.

Emergency Operations

System operators were not immediately notified of system conditions following the disturbance. This was somewhat unfortunate, because the system did not respond normally due to the failure to separate into two islands.

Refer to: Guide III.E., Emergency Information Exchange

WSCC employs two methods of sharing emergency information, namely the WSCC Hot Line and the WSCC Computer-Based Communication System. The Communication System consists of individual communication links to a host computer system for selective broadcasting of general information on the state of the system. In addition, the four Subregion dispatch offices of WSCC are connected through a direct telephone hot line. The primary use of the hot line is to coordinate system restoration following a disturbance. Failure to use available communication systems in a timely manner did not significantly delay system restoration. However, the lack of immediate communication of information made it difficult to assess system conditions and contributed to minor delays.

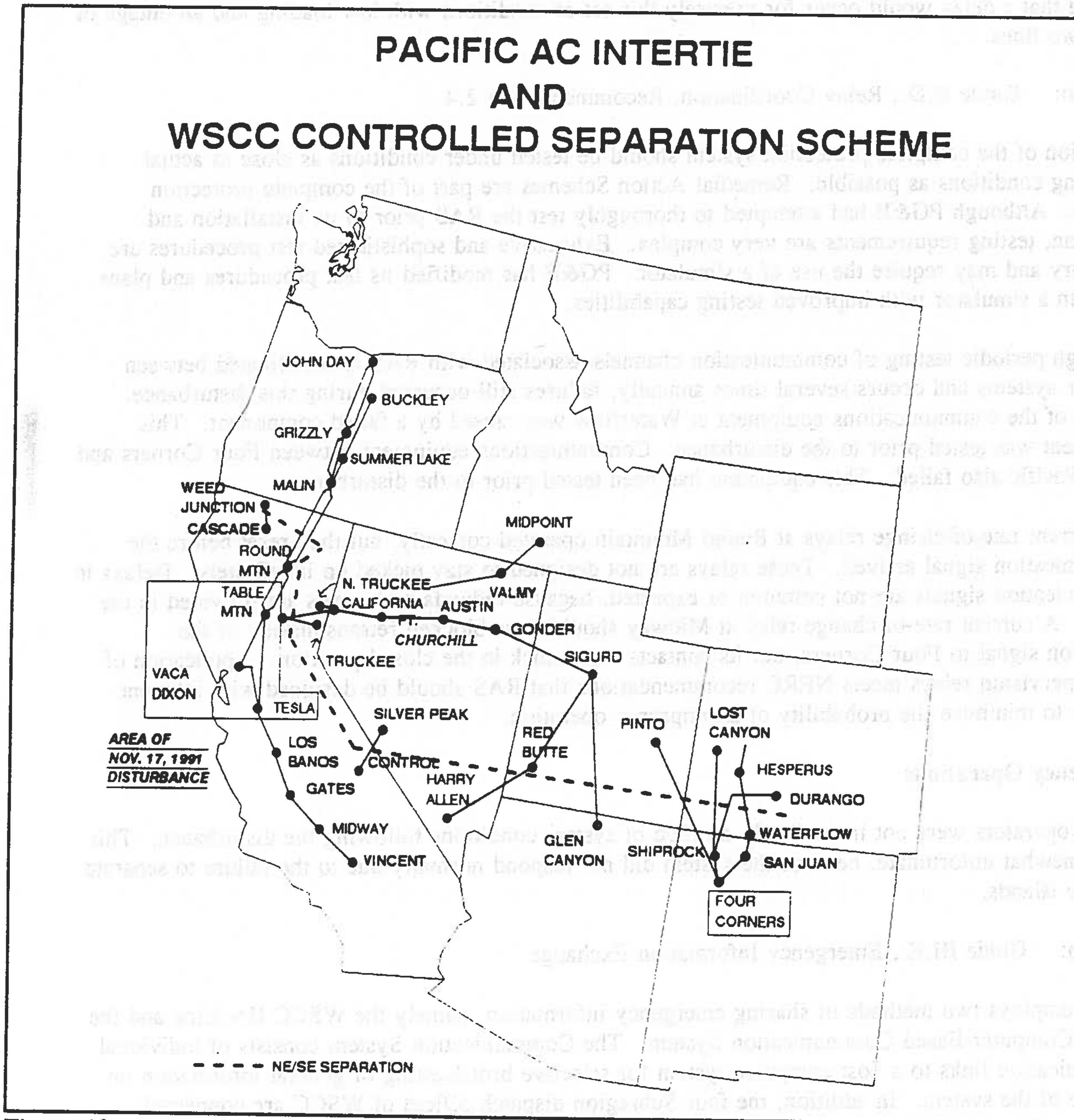


Figure 13 — *Pacific AC Intertie and WSCC Controlled Separation Scheme*

Geomagnetic Disturbances in 1991

Summary

Solar Cycle 22, the one we are now in, began in 1986, reached its peak in July 1989 (the solar max), and has been one of the most active ever recorded. The geomagnetic disturbance (GMD) of March 13-14, 1989, was one of the most intense recorded this century (the *1989 System Disturbances* report contains a detailed explanation of this storm). In 1991, electric utilities felt the effects of three strong geomagnetic disturbances: March 23-24, October 28-30, and November 8-9. (See Graph 2, plus explanation of K and A Indexes that follows.) A strong burst of solar activity occurred during June as well, with levels approaching the March 1989 storm. Yet, only scattered, minor events occurred on the transmission systems. (See chronology on pages 52 through 54.) Graph 2 shows the K and A levels for the 1989 and 1991 storms.

Measurement of Solar Cycles

Solar cycles can be measured three ways:

Smoothed Sunspot Number — similar to a moving average of observed sunspots. Using this measure, Cycle 22 will probably be the third largest cycle on record.

Smoothed 10.7 cm Radio Flux — emissions from the sun. This measure marks Cycle 22 as the second largest on record.

Geomagnetic Storm Days — a separate magnetic storm cycle that lags the sunspot cycle by three to five years. Few cycles exist for which geomagnetic data is available, so future trends are difficult to predict.

It appears that the solar max for Cycle 22 was in July 1989, so we could expect the geomagnetic storm days to peak in 1992-1994. Therefore, the 1991 storms may be the initial disturbances of the approaching peak for Cycle 22. Some scientists speculate that we are entering a more disturbed period after a lull of nearly 30 years.

Utility Responses to 1991 GMDs

The GMDs in 1991 did not cause as much damage as the March 1989 event because the 1991 disturbances were less severe. Also, using what they learned from the 1989 events, the utilities knew what symptoms to look for and took action to mitigate the effects of the GMDs on their systems. For example, on March 23, PJM limited transfers and on October 28, reduced the output at its Salem plant whose generator step-up transformers are very susceptible to GMDs because of their location. New York Power Pool canceled transmission line work on March 24. Allegheny Power adjusted its protection schemes on capacitor banks and enabled gas accumulation detectors and sudden pressure relays on key transformers on October 28.

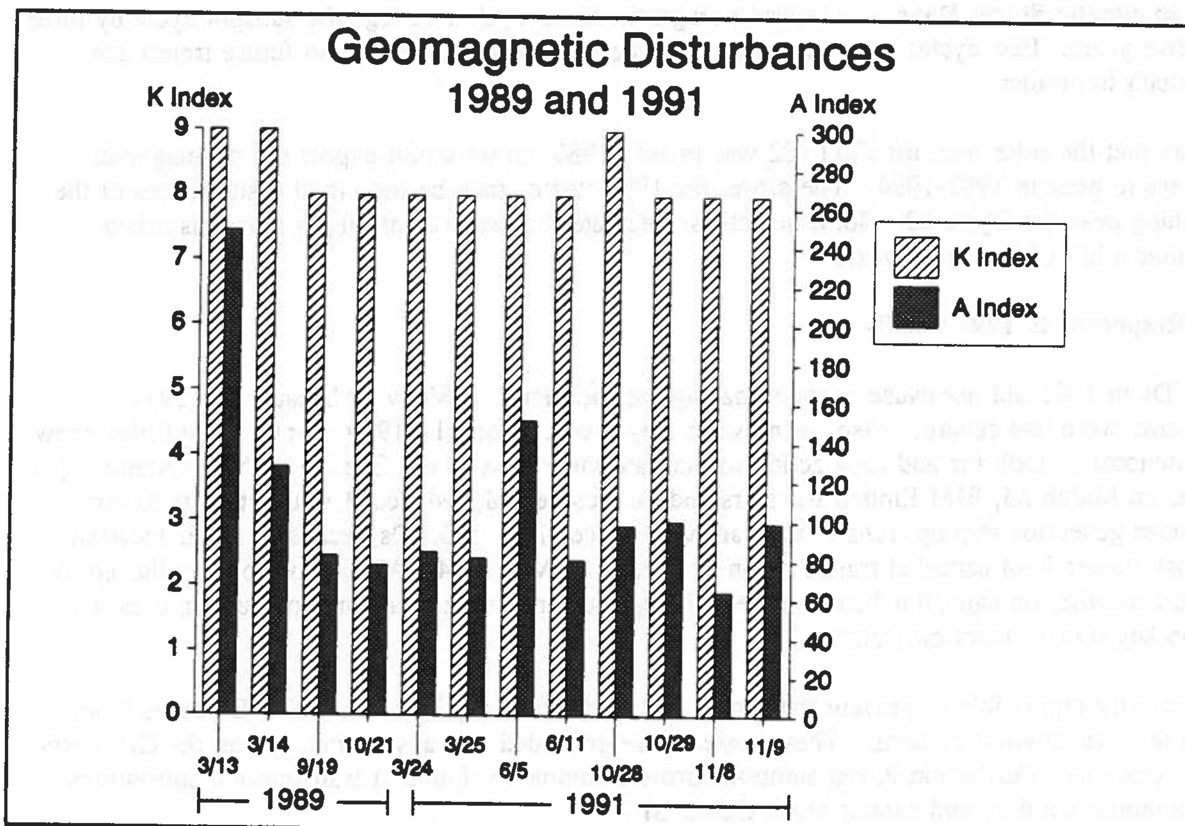
It is practically impossible to prevent the ground-induced currents (GICs) that a GMD causes from entering the transmission systems. These systems are grounded at many points, giving the GIC entry at many locations. Furthermore, the autotransformers commonly found at transmission substations have a common winding and cannot block the dc GIC.

Maintaining adequate reactive reserves on the transmission system is extremely critical during GMDs for two reasons: First, the dc GIC saturates transformer cores in one direction and increases their var requirements. Second, capacitors and static var compensators are sensitive to the second harmonics generated from this saturation and will trip out on excessive current (capacitors offer a lower impedance to the 120 Hz second harmonic). Thus, the transmission system can find itself with local reactive deficiencies that could cause a voltage collapse.

The K and A Indexes

The K index is an indicator of the average local geomagnetic activity over a three-hour period. It is based on a quasi-logarithmic scale that ranges from 0 to 9. A K9 disturbance is the minimum indicator of the most severe storm. It is also the maximum indicator, because the K scale is open-ended. There is nothing above K9.

Graph 2 shows the relational scale that converts the three-hour K index into the 24-hour A index, which is also expressed in nano-Teslas. In the U.S., K and A indexes are measured in Boulder, Colorado. (Boulder is the headquarters of the National Oceanic and Atmospheric Administration's Space Environmental Services Center (SESC). In Canada, these measurements are taken in Ottawa by the Ministry of Energy, Mines, and Resources (EMR). Both national agencies issue K and A index alerts and warnings to each country.



Graph 2 — *K and A levels for 1989 and 1991 geomagnetic disturbances*

Chronology of Events

Event #	Date	Eastern Time From	Eastern Time To	System	Event or Action
1	3/23/91	2200	100	Allegheny Power System	GMD alert of K6
2	3/23/91	2243		PJM	Alburtis and Juniata fault recorder operation
3	3/23/91	2244		PJM	Missouri Avenue neutral dc current spikes to 21.5 amps
4	3/23/91	2258		PJM	Salem #2 and Hope Creek #1 reducing to 80% power due to excess VAR alarm
5	3/23/91	2308		PJM	PJM initiates GMD Transfer Limit Reductions
6	3/24/91	20		Allegheny Power System	Mt. Storm, Meadow Brook, Morrisville line tripped and reclosed. Meadow Brook #4 500/138 kV transformer tripped on gas and harmonic alarm. GIC=45 amps
7	3/24/91	134		PJM	Conemaugh-Hunterstown-Conastone line work canceled due to GMD activity
8	3/24/91	153		Allegheny Power System	Extends GMD alert from 0100 to 1700
9	3/24/91	205		Allegheny Power System	A index greater than 30
10	3/24/91	223		NYPP	Branchburg-Ramapo line work canceled
11	3/24/91	317		PJM	Hope Creek moving toward full load
12	3/24/91	334		PJM	Transfer limits restored to normal
13	10/28/91	600		NYPP	GMD alarm state
14	10/28/91	600			K7
15	10/28/91	1030		Wisconsin Electric Power	Transformer noise at Point Beach plant
16	10/28/91	1037	1040	So. Calif. Edison	500 kV transmission voltage dropped 11-12 kV
17	10/28/91	1037	1039	BPA	Shunt capacitors tripping at several substations. Strange transformer noises. 500 kV transmission voltage dropped 7-9 kV.
18	10/28/91	1038		PS New Mexico	Blackwater dc tie tripped
19	10/28/91	1040		Hydro-Québec	Radisson-Sandy Pond Phase II dc line tripped carrying 930 MW
20	10/28/91	1041		Virginia Power	Dooms capacitors (230 kV-100 Mvar) tripped on neutral unbalance. 230 kV, 150 Mvar.
21	10/28/91	1041		Virginia Power	Chuckatuck capacitors (230 kV-150 Mvar) tripped on neutral unbalance. 230 kV, 100 Mvar.
22	10/28/91	1041		Allegheny Power System	K8 - Meadow Brook T4 making loud noise and visibly vibrating

Event #	Date	Eastern Time		System	Event or Action
		From	To		
23	10/28/91	1055		Allegheny Power System	Global protection scheme enabled: Unbalance protection removed from 138 kV capacitors. Gas accumulation detectors (200 cc of free gas) and sudden pressure relays enabled.
24	10/28/91	1101		So. Calif. Edison	Neutral current at Serrano substation at 150-200 amps
25	10/28/91	1101	1104	So. Calif. Edison	500 kV transmission voltage dropped 8-9 kV
26	10/28/91	1102		Virginia Power	Staunton capacitors (115 kV-25 Mvar) tripped on neutral unbalance
27	10/28/91	1300			K9
28	10/28/91	2200			K7
29	10/28/91	2220			K6
30	10/28/91	2254	2257	PJM	Missouri Avenue dc GIC alarm reading = 12.7 amps on transformer
31	10/28/91	2258		PJM	Salem #1 and #2 dropped to 80% power due to GMD
32	10/28/91	2259		Allegheny Power System	T4 Meadow Brook transformers tripped on gas detection
33	10/28/91	2302		PJM	Salem #1 at 843 MW, Salem #2 at 845 MW
34	10/28/91	2316		Allegheny Power System	Removed T2 Meadow Brook transformers
35	10/29/91	128	435	PJM	PJM initiates GMD Transfer Limit Reductions
36	10/29/91	642		PJM	Salem ramping to full load
37	10/29/91	958		NYPP	In GMD alarm state since previous day. With K7 or greater, transmission limited to 90% of normal ratings. Limit hit on #71 line.
38	10/29/91	1104			GMD forecast for today and tomorrow
39	10/30/91	924		Allegheny Power System	Meadow Brook T2 returned to service
40	10/30/91	1108		Allegheny Power System	Meadow Brook T4 returned to service
41	10/30/91	1140		Allegheny Power System	Global protection scheme disabled
42	11/08/91	1137			
43	11/08/91	1545			K7
44	11/08/91	1718			K6
45	11/08/91	1731		Allegheny Power System	Meadow Brook T4 harmonic alarm

Event #	Date	Eastern Time		System	Event or Action
		From	To		
46	11/08/91	1731		Allegheny Power System	Meadow Brook T4 gas relay tripped Mt. Storm-Meadow Brook-Morrisville 500 kV line. 300 cc gas collected at Meadow Brook. All terminals reclosed.
47	11/08/91	1732		Allegheny Power System	Meadow Brook 138 kV breakers open. T2 and T4 transformers removed.
48	11/08/91	1900		Allegheny Power System	Meadow Brook T2 returned
49	11/08/91	2257		Allegheny Power System	K7
50	11/09/91	100	400	Allegheny Power System	K6
51	11/09/91	900	1200	Allegheny Power System	K5
52	11/09/91	1657		Allegheny Power System	Meadow Brook T4 transformer returned

Geomagnetic Disturbances in 1991 — Hydro-Québec Radisson Substation Trip

Introduction

On Monday, October 28, 1991 at 1037, converter #2 at the Radisson substation tripped while the Hydro-Québec power system was under the effect of an intense GMD rated K9. Following the alert from Ottawa (Energy, Mines and Resources), the operating strategies for magnetic storm conditions had been in force since 0740 that morning.

System Status

The multi-terminal dc system was operating in the Radisson-Sandy Pond configuration in monopolar mode with metallic return. The Radisson converter was synchronous with the Hydro-Québec system. Prior to the event, the power flow read at Radisson was 1,087 MW.

Table 7

Québec requirements		17,688 MW
Export requirements	NEPOOL	930 MW at Sandy Pond
	HIGHGATE	167 MW
	NYPA	558 MW
	CEENB	0 MW

735 kV Lines Out of Service Prior to the Event

Two lines on the Churchill Falls system had been withdrawn from service: Montagnais-Arnaud line L7033 and Arnaud-Manicouagan line L7029. One Manicouagan-Lévis line (L7007) was taken out of service, as was one line (L7002) of the Québec City-Montreal grid. All lines of the James Bay system were available and under load.

Table 8

Synchronous Compensators (SC) and Static var Compensators (SVC) Out of Service Prior to the Event			
Némiscau	1 SVC	Manicouagan	2 SVCs
Abitibi	1 SC	Lévis	1 SC
Chibougamau	1 SVC	Duvernay	1 SC

Power Flows

The table below shows the differences between maximum and actual transfer levels were significant.

Table 9

	System		
	James Bay	**Manic-Québec**	**Churchill**
Maximum transfer level with Radisson synchronous at 1,100 MW	8,300 MW	6,600 MW	3,300 MW
Actual transfer prior to the event	7,233 MW	5,047 MW	2,713 MW
Margin	13%	24%	18%

Event

Radisson converter #2 tripped, causing a 1,087 MW loss of export (read at Radisson) to the NEPOOL grid. The static compensator at the Laurentides substation also tripped 74 seconds later.

Cause

The Radisson converter was tripped by the harmonic overcurrent protection system on the HVDC line. The harmonics on that line were caused by harmonic currents on the ac side as a result of the magnetic storm. Indeed, analysis of the 315 kV voltage waveforms for Radisson indicated a second-order harmonic content (120 Hz) in excess of 10%. That distortion of the ac waveform generated 180 Hz on the dc side. A design review is in progress with the manufacturer to devise a means of preventing tripping under similar conditions without jeopardizing equipment security.

The Laurentides static compensator was tripped by a differential relay on the shunt reactors making up the 5th and 7th harmonic filter. That differential protection scheme was already unbalanced under normal operating conditions.

Impact on Power System

With almost 1,100 MW of overgeneration, overfrequency on the Hydro-Québec system reached 60.93 Hz. The voltage drop across the system resulted from the combined impact of the additional power transferred along the James Bay grid and the geomagnetic disturbance.

Action

Since this event, the System Control Centre has been issued an interim order to operate the Radisson substation in islanded configuration during magnetic storm alerts. The operation and settings of the harmonic current protection system on the Radisson HVDC line are being examined.

The Laurentides static compensator was restored to service without differential protection of the shunt reactor. The situation has since been corrected, and the compensator restored to normal service.

Impact on Telecommunication Network

The geomagnetic disturbance had no appreciable impact on operation of Hydro-Québec's telecommunication network.

Conclusion

The event proved more serious than simple tripping of the converter because the GMD had already produced frequency and voltage fluctuations along the system. The static compensators on the La Grande system performed well following changes designed to enhance their reliability under magnetic storm conditions. Although the event was serious, a large margin of stability was preserved given the level of power flows.

The operation and settings of the harmonic current protection systems on the HVDC line at Radisson are being analyzed with the manufacturer.

The anomalies in the Laurentides static compensator have been remedied.

The fall 1992 commissioning of blocking series capacitors on the Radisson-Némiscau and LG2-Chissibi lines should block dc flow through the transmission network and thus substantially mitigate the effects of GMDs at the Radisson substation.

Appendix A — Reporting Requirements for Major Electric Utility System Emergencies

Every electric utility or other entity subject to the provisions of Section 311 of the Federal Power Act, engaged in the generation, transmission, or distribution of electric energy for delivery and/or sale to the public shall expeditiously report to the U.S. Department of Energy's (DOE) Emergency Operation Center (EOC) any of the events described in the following. (A report or a part of a report required by DOE may be made jointly by two or more entities or by a Regional Council or power pool.)

A. Loss of Firm System Loads

1. Any load shedding actions resulting in the reduction of over 100 megawatts (MW) of firm customer load for reasons of maintaining the continuity of the bulk electric power supply system.

2. Equipment failures/system operational actions which result in the loss of firm system loads for a period in excess of 15 minutes, as described below:

   2.1. Reports from entities with a previous year recorded peak load of over 3,000 MW are required for all such losses of firm loads which total over 300 MW.

   2.2. Reports from all other entities are required for all such losses of firm loads which total over 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.

3. Other events or occurrences which result in a continuous interruption for three hours or longer to over 50,000 customers, or more than 50% of the system load being served immediately prior to the interruption, whichever is less.

NOTE: The DOE EOC shall be notified as soon as practicable without unduly interfering with service restoration and, in any event, within three hours after the beginning of the interruption.

B. Voltage Reductions or Public Appeals

1. Reports are required for any anticipated or actual system voltage reductions of three percent or greater for purposes of maintaining the continuity of the bulk electric power supply system.

2. Reports are required for any issuance of a public appeal to reduce the use of electricity for purposes of maintaining the continuity of the bulk electric system.

NOTE: The DOE EOC shall be notified as soon as practicable, but no later than 24 hours after initiation of the actions described in this section.

C. Vulnerabilities That Could Impact Bulk Electric Power System Adequacy or Reliability

1. Reports are required for any actual or suspected act(s) of physical sabotage (not vandalism) or terrorism directed at the bulk electric power supply system in an attempt to either:

   1.1. Disrupt or degrade the adequacy or service reliability of the bulk electric power system such that load reduction action(s) or a special operating procedure is or may be needed.

   1.2. Disrupt, degrade, or deny bulk electric power service on an extended basis to a specific: (1) facility (industrial, military, governmental, private), (2) service (transportation, communications, national security), or (3) locality (town, city, country). This requirement is intended to include only major events involving the supply of bulk power.

D. Reports for Other Emergency Conditions or Abnormal Events

1. Reports are required for any other abnormal emergency system operating conditions or other events which, in the opinion of the reporting entity, could constitute a hazard to maintaining the continuity of the bulk electric power supply system. DOE has a special interest in actual or projected deterioration in bulk power supply adequacy and reliability due to any causes. Events which may result in such deterioration include, but are not necessarily limited to: natural disasters; failure of a large generator or transformer; extended outage of a major transmission line or cable; federal or state actions with impacts on the bulk electric power system.

NOTE: The DOE EOC shall be promptly notified as soon as practicable after the detection of any actual or suspected acts(s) or event(s) directed at increasing the vulnerability of the bulk electric power system. A 24-hour maximum reporting period is specified in the regulations; however, expeditious reporting, especially of sabotage or suspected sabotage activities, is requested.

E. Fuel Supply Emergencies

1. Reports are required for any anticipated or existing fuel supply emergency situation which would threaten the continuity of the bulk electric power supply system, such as:

   1.1. Fuel stocks or hydroelectric project water storage levels are at 50% or less of normal for that time of the year, and a continued downward trend is projected.

   1.2. Unscheduled emergency generation is dispatched causing an abnormal use of a particular fuel type, such that the future supply or stocks of that fuel could reach a level which threatens the reliability or adequacy of electric service.

NOTE: The DOE EOC shall be notified as soon as practicable, or no later than three days after the determination is made.

Appendix C — Disturbances, Demand Reductions, and Unusual Occurrences — 1991

(Analyses of items in boldface are included in this report.)

Date	Region	Utility or Area	Type	Firm Load MW	Firm Load Customers	Cause
01/17/91	ECAR	Detroit Edison	UO	0	0	Tower vandalism
01/25/91	NPCC	Hydro-Québec	INT	350	25,000	Transformers tripped
01/28/91	NPCC	Hydro-Québec	INT	570	35,000	Current transformer fault
03/03/91	NPCC	Rochester Gas & Electric, Niagara Mohawk	INT	n/a	315,000	Ice storm
03/04/91	**WSCC**	**Pacific Gas & Electric, Bonneville Power Admin., Calif. Dept. of Water Resources, Arizona Public Service, Sierra Pacific Power**	**INT**	**993**	**176**	**Line outage**
03/12/91	**ECAR, MAIN**	**PSI Energy, American Electric Power, Commonwealth Edison**	**INT**	**n/a**	**500,000**	**Ice storm**
03/23/91	NPCC, MAAC, ECAR	Various	UO	0	0	Geomagnetic storm
03/27/91	ECAR	Consumers Power Co., Detroit Edison Co.	INT	300	404,000	Windstorm
04/09/91		Hawaiian Electric Company	INT	950	246,000	Transmission outages
04/09/91	**ECAR, SERC**	**American Electric Power, Allegheny Power System, TVA**	**UO**	**0**	**0**	**Storms**
04/13/91	SERC	Virginia Power	INT	300	43,696	**Pole fire**
04/25/91	SERC	Florida Power Corporation	INT	213	71,000	Storms
04/26/91	**SPP**	**Kansas Gas & Electric, Oklahoma Gas & Electric, Public Service Company of Oklahoma**	**INT**	**450**	**94,900**	**Tornadoes**
04/29/91	**SERC**	**Florida Power & Light Company, Florida Power Corporation**	**PA**	**0**	**0**	**Hot weather**
05/01/91	SERC	Florida systems	PA	0	0	Heat wave
05/21/91	NPCC	Hydro-Québec	INT	327	30,000	Current transformer explosion
05/23/91	NPCC	Hydro-Québec	INT	230	20,000	Lightning
07/01/91	WSCC	Pacific Gas & Electric Co., Los Angeles Department of Water & Power	INT	0	0	Converter trip
07/07/91	ECAR	Detroit Edison, Consumers Power	INT	1,000	899,000	Storms
07/16/91	**WSCC**		**INT**	**7**	**1**	**Line fault**
07/22/91	NPCC	Consolidated Edison	INT	240	10,300	Breaker trip
07/24/91	**SERC**	**Duke Power Company**	**UO**	**n/a**	**490,000**	**Plant trip**
08/08/91	**SERC**	**Nashville Electric System, several co-ops**	**INT**	**1,061**	**115,000**	**Capacitor bank failure**
08/19/91	NPCC	New York Power Pool, New England Electric Exchange	INT	4,400	2,085,000	Hurricane Bob
09/12/91	**WSCC**	**SE Idaho and SW Wyoming**	**INT**	**335**	**206,000**	**Lightning storm**
10/28/91			UO	0	0	Geomagnetic storm
10/31/91	**MAPP**	**Several**	**INT**	**80**	**0**	**Snow & ice storm**
11/15/91	SERC	Alabama Power Company	UO	0	0	Generator fire
11/16/91	WSCC	Several utilities in Northwest Power Pool	INT	0	400,000	Storm
11/17/91	**WSCC**		**UO**	**n/a**	**0**	**Static wire failure**

UO = Unusual Occurrence
INT = Interruption
VR = Voltage Reduction
PA = Public Appeal

Appendix B — Analysis Categories

The categories the Group used when analyzing the disturbances and unusual occurrences are the titles and subtitles of the NERC Operating Guides:

GUIDE I. SYSTEM CONTROL

A. Generation Control
B. Voltage Control
C. Time and Frequency Control
D. Interchange Scheduling
E. Control Performance Criteria
F. Inadvertent Interchange Management
G. Control Surveys
H. Control Equipment Requirements

GUIDE II. SYSTEM SECURITY

A. Real Power (MW) Supply
B. Reactive Power (MVAR) Supply
C. Transmission Operation
D. Relay Coordination
E. Monitoring Interconnection Parameters
F. Information Exchange — System Conditions
G. Information Exchange — Disturbance Reporting
H. Information Exchange — Sabotage Reporting
I. Maintenance Coordination

GUIDE III. EMERGENCY OPERATIONS

A. Insufficient Generation Capacity
B. Transmission — Overload, Voltage Control
C. Load Shedding
D. System Restoration
E. Emergency Information Exchange
F. Special System or Control Area Action
G. Control Center Backup

GUIDE IV. OPERATING PERSONNEL

A. Responsibility and Authority
B. Selection
C. Training
D. Responsibility to Other Operating Groups

GUIDE V. OPERATIONS PLANNING

A. Normal Operations
B. Planning for Emergency Conditions
C. Long-Term Deficiencies
D. Load Shedding
E. System Restoration

GUIDE VI. COMMUNICATIONS

A. Facilities
B. System Operator Communication Procedures
C. Loss of Communications

PLANNING POLICIES AND GUIDES

Appendix D — Summary of Disturbances by Analysis Category

Guide I.D. Systems Control — Interchange Scheduling

American Electric Power, Allegheny Power System, PJM Interconnection Severe Thunderstorms — April 9, 1991 — Plant operator allowed generators to temporarily exceed their field current limits to allow transmission voltages to return to normal.

Iowa/Minnesota/Nebraska Ice Storm — October 31, 1991 — Reduced interchange capability between utilities across Regional boundaries required utilities to adjust interchange limits.

Guide II.A. System Security — Real Power (MW) Supply

Florida Capacity Alert — April 29, 1991 — Statewide capacity assessment procedure worked well during capacity emergency. Some discrepancies existed in how reserves were counted and actual amounts.

Guide II.C. System Security — Transmission Operation

Illinois/Indiana Ice Storm — March 12-13, 1991 — System operators backed down generators to prevent transmission overloads or instability.

Guide II.D. System Security — Relay Coordination

Pacific AC Intertie Separation — March 4, 1991 — A bad connection in a multi-conductor plug was not detected when the relay was tested separately.

Four Corners Units 3, 4, and 5 Trip — July 16, 1991 — The impact of temporary modifications to a relay were not considered.

Tennessee Valley Authority South Nashville 161 kV Substation Fault — August 8, 1991 — Utility did not employ local breaker failure systems at substation when it was constructed.

SE Idaho/SW Wyoming Outage — September 12, 1991 — Non-redundant special protection system failed because telemetry that automatically arms the system was out of calibration.

Pacific AC Intertie Separation — November 17, 1991 — Special protection systems did not operate as intended. A software error programmable logic controller delayed initiating the systems.

Guide II.E. System Security — Monitoring Interconnection Parameters

Illinois/Indiana Ice Storm — March 12-13, 1991 — Large number of alarms slowed computer response, which delayed isolation and restoration of transmission lines.

American Electric Power, Allegheny Power System, PJM Interconnection Severe Thunderstorms — April 9, 1991 — Utility could not monitor critical transmission lines outside its boundaries.

SE Idaho/SW Wyoming Outage — September 12, 1991 — System monitoring did not reveal that a special protection system was not armed.

Appendix D — Summary of Disturbances by Analysis Category

Guide II.F. System Security — Information Exchange — System Conditions

Illinois/Indiana Ice Storm — March 12-13, 1991 — With the wide extent of the outage, broader and earlier dissemination of system information could have helped other utilities to plan better for contingencies that could have occurred.

American Electric Power, Allegheny Power System, PJM Interconnection Severe Thunderstorms — April 9, 1991 — Utility did not have automated communications system to receive line outage information rapidly.

Guide II.G. System Security — Information Exchange — Disturbance Reporting

Illinois/Indiana Ice Storm — March 12-13, 1991 — With the wide extent of the outage, broader and earlier dissemination of system information could have helped other utilities to plan better for contingencies that could have occurred.

Guide III.A. Emergency Operations — Insufficient Generation Capacity

Florida Capacity Alert — April 29, 1991 — Some utilities thought they could not violate operating reserve criteria by selling reserves to help other utilities.

Guide III.D. Emergency Operations — System Restoration

Illinois/Indiana Ice Storm — March 12-13, 1991 — Restoration of the transmission system was planned by prioritizing the needs of the bulk electric system. Downed structures required three to five months to restore.

American Electric Power, Allegheny Power System, PJM Interconnection Severe Thunderstorms —April 9, 1991 — System operators took quick action to reduce imports as soon as critical transmission lines tripped out.

Guide III.E. Emergency Operations — Emergency Information Exchange

Pacific AC Intertie Separation — November 17, 1991 — System operators were not immediately notified of system conditions following the disturbance.

Guide IV.A. Operating Personnel — Responsibility and Authority

Florida Capacity Alert — April 29, 1991 — This incident showed the importance of having load control programs directly available to system operators.

Guide V.A. Operations Planning — Normal Operations

Duke Power Company Belews Plant Outage — July 24, 1991 — Additional studies regarding on-line and off-line voltage prediction may be helpful.

Iowa/Minnesota/Nebraska Ice Storm — October 31, 1991 — The long-term outage of key transmission lines requires planning engineers to review the operating limitations of the systems.

Appendix D — Summary of Disturbances by Analysis Category

Guide V.B. Operations Planning — Planning for Emergency Conditions

Illinois/Indiana Ice Storm — March 12-13, 1991 — Utilities affected by transmission outages adjusted their transfer limits to continue operating reliably.

American Electric Power, Allegheny Power System, PJM Interconnection Severe Thunderstorms — April 9, 1991 — Post-event analysis shows that computer simulations would have accurately predicted the voltage drop that occurred after critical lines tripped out.

Guide V.E. Operations Planning — System Restoration

Tennessee Valley Authority South Nashville 161 kV Substation Fault — August 8, 1991 — Severely depressed voltage allowed backup distance and 13 kV underground relays to operate. Some customers were out for more than two hours.

Guide VI.A Telecommunications — Facilities

Four Corners Units 3, 4, and 5 Trip — July 16, 1991 — Failure of communications equipment delayed restoration of firm load at the plant switchyard.

Appendix E — North American Electric Reliability Council Planning Policies

The North American Electric Reliability Council was formed in 1968 and incorporated in 1975: to promote the reliability of bulk power supply by the electric systems of North America; to conduct interregional studies which relate to the reliability of the bulk electric systems and to make information appropriately available; to encourage and assist the development of interregional reliability arrangements among Regional Councils and their members; to exchange information with respect to planning and operating matters relating to the reliability of bulk power supply; and to review periodically regional and interregional activities on reliability.

To achieve this purpose, the NERC Board of Trustees has approved this document delineating the responsibilities of the various entities within NERC for the development of reliability criteria and planning guides to be applied in the planning of the interconnected bulk electric systems of North America.

- The NERC Engineering Committee develops Planning Guides which describe good practices for bulk electric system planning.

- The Regional Councils, Subregions, Pools and/or the Individual Systems, which have the primary responsibility for the reliability of bulk power supply, develop:

  Reliability criteria applicable to their Region or area for use in planning and designing bulk electric systems. Among the factors considered in developing criteria are: generation adequacy; predisturbance conditions; adequacy and security performance testing; acceptable system response; prevention of system instability, cascading overloads, and voltage collapse; system protection philosophy; and measures to facilitate system restoration.

  Criteria dealing with other matters, such as the application and coordination of automatic underfrequency load shedding, the design and maintenance of protective relaying systems and remedial action systems, load forecasting considerations, the rating of generating capacity, and the recording of system parameters.

  Arrangements to assure that interregional effects on reliability are reviewed and to encourage coordination of planning among Regions.

The criteria and guides developed at all levels are reviewed at appropriate intervals by the originating entity and modified as appropriate.

Approved by Engineering Committee: February 28, 1989
Approved by Board of Trustees: April 4, 1989

Appendix E — North American Electric Reliability Council Planning Guides

These Planning Guides describe the characteristics of a reliable bulk electric system. They are intended to provide guidance to the Regional Councils, Subregions, Pools, and/or the Individual Systems in planning their bulk electric systems.

- To the extent practicable, a balanced relationship is maintained among bulk electric system elements in terms of size of load, size of generating units and plants, and strength of interconnections. Application of this guide includes the avoidance of:

  Excessive concentration of generating capacity in one unit, at one location or in one area;

  Excessive dependence on any single transmission circuit, tower line, right-of-way, or transmission switching station; and

  Excessive burdens on neighboring systems.

- The system is designed to withstand credible contingency situations.
- Dependence on emergency support from adjacent systems is restricted to acceptable limits.
- Adequate transmission ties are provided to adjacent systems to accommodate planned and emergency power transfers.
- Reactive power resources are provided which are sufficient for system voltage control under normal and contingency conditions, including support for a reasonable level of planned transfers and a reasonable level of emergency power transfers.
- Adequate margins are provided in both real and reactive power resources to provide acceptable dynamic response to system disturbances.
- Recording of essential system parameters is provided for both steady state and dynamic system conditions.
- System design permits maintenance of equipment without undue risk to system reliability.
- Planned flexibility in switching arrangements limits adverse effects and permits reconfiguration of the bulk power transmission system to facilitate system restoration.
- Protective relaying equipment is provided to minimize the severity and extent of system disturbances and to allow for malfunctions in the protective relay system without undue risk to system reliability.
- Black start-up capability is provided for individual systems.
- Fuel supply diversity is provided to the extent practicable.

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North American Electric Reliability Council

ECAR
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ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

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