NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

# 1997 System Disturbances

## Review of Selected Electric System Disturbances in North America

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**April 2004**

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# Foreword

The Disturbance Analysis Working Group of the North American Electric Reliability Council (NERC) Operating Committee prepared this review of selected 1997 bulk electric system disturbances, unusual occurrences, demand and voltage reductions, and public appeals.

NERC has published its findings on bulk electric system disturbances, unusual occurrences, demand and voltage reductions, and public appeals since 1979. The objectives of this report include:

- Sharing the experiences and lessons that North American utilities have learned.
- Suggesting ways that utilities can apply the NERC operating policies to their operations and the NERC planning standards to their planning.
- Determining if these policies and standards adequately address the normal and emergency conditions that can occur on the bulk electric systems.

The working 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 John Theotonio at NERC at 609-452-8060.

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# Introduction

The U.S. Department of Energy (DOE) has established requirements for reporting major electric utility system emergencies (**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 it must report to DOE, the utility sends a copy of the report to its regional council, which then sends a copy to NERC. Canadian utilities often voluntarily file emergency reports with DOE and NERC as well.

NERC's annual review of system disturbances begins in November when the Disturbance Analysis Working Group (DAWG) 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 summarizes the report for this review and analyzes it using the NERC operating policies and planning standards as the analysis categories. (A list of these categories is found on Page 5–6.)

The Commentary section includes the conclusions and recommendations that were formulated from the analyses in this report plus the general expertise of the working group members.

In 1997, utilities reported 28 incidents of system disturbances, demand reductions, voltage reductions, public appeals, or unusual occurrences, one less than was reported in 1996. These incidents are listed chronologically in **Appendix C** and categorized as:

- Eighteen system interruptions
- Five unusual occurrences
- One interruption and public appeal
- Two demand reductions
- One public appeal
- One voltage reduction

This document contains analyses of five incidents. The recommendations included in each analysis are from the Region, pool, or utility and not from the Disturbance Analysis Working Group.

Tables of disturbances by analysis category that offer quick reviews of the operating and planning categories applicable to each incident are on pages 7–9.

# Analysis Categories

The categories used to analyze the disturbances and unusual occurrences are the titles and subtitles of the NERC operating policies, plus the NERC planning standards.

## Operating Policies

### Policy I. — Generation Control and Performance

A. Operating Reserve
B. Automatic Generation Control
C. Frequency Response and Bias
D. Time Control
E. Performance Standard
F. Inadvertent Interchange Standard
G. Control Surveys
H. Control and Monitoring Equipment

### Policy 2. — Transmission

A. Transmission Operations
B. Voltage and Reactive Control

### Policy 3. — Interchange

A. Interchange Transaction Implementation
B. Interchange Schedule Implementation
C. Interchange Schedule Standards
D. Interchange Transaction Cancellation, Termination, and Curtailment

### Policy 4. — System Coordination

A. Monitoring System Conditions
B. Operational Security Information
C. Maintenance Coordination
D. System Protection Coordination

### Policy 5. — Emergency Operations

A. Coordination with Other Systems
B. Insufficient Generating Capacity
C. Transmission System Relief
D. Separation from the Interconnection
E. System Restoration
F. Disturbance Reporting
G. Sabotage Reporting

### Policy 6. — Operations Planning

A. Normal Operations
B. Emergency Operations
C. Automatic Load Shedding
D. System Restoration
E. Control Center Backup

### Policy 7. — Telecommunications

A. Facilities
B. System Operator Telecommunication Procedures
C. Loss of Telecommunications

### Policy 8. — Operating Personnel and Training

A. Responsibility and Authority
B. Training
C. Certification

### Policy 9. — Security Coordinator Procedures

A. Next Day Operations Planning Process
B. Current Day Operations – Energy
C. Current Day Operations – Transmission

## Planning Policies

I. Forecast

II. Resources

Guides
A. General
B. Demand-side Resources
C. Supply-side Resources

III. Transmission

Guides
A. Adequacy
B. Security
C. Coordination
D. Protection Systems

## Planning Standards

I. System Adequacy and Security

A. Transmission Systems
B. Reliability Assessment
C. Facility Connection Requirements
D. Voltage Support and Reactive Power
E. Transfer Capability
F. Disturbance Monitoring

II. System Modeling Data Requirements

A. System Data
B. Generation Equipment
C. Facility Ratings
D. Actual and Forecast Demands
E. Demand Characteristics (Dynamic)

III. System Protection and Control

A. Transmission Protection Systems
B. Transmission Control Devices
C. Generation Control and Protection
D. Underfrequency Load Shedding
E. Under-voltage Load Shedding
F. Special Protection Systems

IV. System Restoration

A. System Blackstart Capability
B. Automatic Restoration of Load

# Disturbances by Analysis Category

## Operating Policies

| Operating Policies | Incident Number | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| **Policy 1. Generation Control and Performance** | | | | | |
| B. — Automatic Generation and Control | | | | X | |
| E. — Control Performance | | | | X | |
| **Policy 2. Transmission** | | | | | |
| A. — Transmission Operations | | X | | | X |
| B. — Voltage and Reactive Control | | | | | X |
| **Policy 3. Interchange** | | | | | |
| A. — Interchange Transactions | | X | | | |
| B. — Interchange Schedules | | X | | | |
| E. — Transfer Capability | | X | | | |
| **Policy 4. System Coordination** | | | | | |
| A. — Monitoring System Conditions | | | | X | |
| B. — Coordination with other systems–Normal Operations | | | | | |
| D. — System Protection Coordination | X | X | X | X | X |
| **Policy 5. Emergency Operations** | | | | | |
| A. — Coordination With Other Systems | X | | | | |
| C. — Transmission Overload | | X | | | |
| D. — Separation from the Interconnection | | | X | | |
| E. — System Restoration | | | | | |
| **Policy 6. Operations Planning** | | | | | |
| A. — Normal Operations | | | | | |
| B. — Emergency Operations | X | X | | | |
| C. — Automatic Load Shedding | | | | | |
| D. — System Restoration | | | | | |
| **Policy 7. Telecommunications** | | | | | |
| A. — Facilities | X | | | | |
| B. — System Operator Telecommunication Procedures | | | | | |
| **Policy 8. Operating Personnel and Training** | | | | | |
| C. — Training | | | X | X | X |

## Planning Policies

| Policies, Procedures, and Principles and Guides for Planning Reliable Bulk Electric Systems | Incident Number | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| **I. Forecast** | | | | | |
| **II. Resources** | | | | | |
| **Guides** | | | | | |
| A. — General | | | X | | |
| B. — Demand-Side Resources | X | | | | |
| C. — Supply-Side Resources | X | | | | |
| **III. Transmission** | | | | | |
| **Guides** | | | | | |
| A. — Adequacy | | X | X | | X |
| B. — Security | X | X | | | X |
| C. — Coordination | | X | | | X |
| D. — Protection Systems | X | X | X | X | X |

## Planning Standards

| Standards for Planning Reliable Bulk Electric Systems | Incident Number | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| **I. System Adequacy and Security** | | | | | |
| A. — Transmission Systems | | | X | | X |
| **II. System Modeling Data Requirements** | | | | | |
| A. — System Data | | | | | X |
| **III. System Protection and Control** | | | | | |
| A. — Transmission Protection Systems | X | X | X | | X |
| C. — Generation Control and Protection | X | X | X | | |
| **IV. System Restoration** | | | | | |
| A. — Blackstart Capability | | | | | |

### *Incident Number*

1. Dakotas–Minnesota Area Wind and Ice Storm — April 4–6, 1997
2. Minnesota–Wisconsin Interface Separation — June 11, 1997
3. Potomac Electric Power Company Disturbance — June 20, 1997
4. 230 kV line Reactor Failure in the Western Interconnection — August 26, 1997
5. Islanding of Generating Station X in the Western Interconnection — September 21, 1997

# Disturbances

## 1. Dakotas-Minnesota Area Wind and Ice Storm — April 4–6, 1997

### Summary

From the late in the evening of Friday, April 4, 1997, until the early morning hours of Sunday, April 6, a severe spring storm moved across North Dakota and northern Minnesota causing numerous outages to high-voltage transmission facilities and distribution lines. The storm, which was preceded in many areas by several inches of rain that turned to ice, dropped 7 to 17 inches of snow. Winds accompanying the storm gusted up to 70 mph and tore down ice-laden transmission lines and structures across the region.

The disturbance began southwest of Bismarck, North Dakota, on Friday, April 4, 1997, at 20:54 CST. The last of the high-voltage transmission lines to be lost during the storm occurred on Sunday, April 6, 1997, at 11:13 CDT. The duration of the disturbance was about 39 hours.

The electric utility transmission and distribution systems serving the 119,458 customers that were left without electric service during the storm lost 564 MW of customer demand — about 21% of the electrical demand within the region. During the disturbance, these systems lost the following high-voltage transmission lines (lines damaged or lines that system protection opened/locked out):

| | |
|---|---|
| Basin Electric Power Cooperative | 2 – 345 kV lines |
| Montana-Dakota Utilities Co. | 1 – 230 kV line, 4 – 115 kV lines |
| Manitoba Hydro | 1 – 230 kV line |
| Minnesota Power | 2 – dc poles |
| Minnkota Power Cooperative, Inc. | 3 – 345 kV lines, 4 – 230 kV lines, 1 – 115kV line |
| Northern States Power Co. | 1 – 230 kV line |
| Otter Tail Power Co. | 3 – 230 kV lines, 11 – 115 kV lines |
| United Power Assn. | 1 – dc pole, 3 – 230 kV lines |
| Western Area Power Admin. | 8 – 230 kV lines, 12 – 115 kV lines |

In addition, more than 3,400 miles of subtransmission (<115 kV) lines were lost and more than 1,500 structures were damaged. No islanding or cascading system breakup occurred during the disturbance. Nor did any significant frequency deviations occur. Significant steady-state voltage excursions occurred in the Grand Forks, North Dakota, area due to the loss of all five 230 kV lines and two of the three 115 kV lines serving the area. Four of the five 230 kV lines were lost at the same time.

One generating unit operating at 425 MW was removed from service due to the storm. Generation in the North Dakota coalfields was limited during the disturbance to protect them from angular instability. About 1,500 MW of generation was scheduled offline prior to the disturbance. This scheduling of generation was fortuitous as it provided added stability margin during the numerous faults and multiple outage conditions, which had never been studied.

Restoration was hampered by impassable roads and near zero visibility throughout the region caused by the blizzard conditions. Record flooding in the Red River valley, and particularly in the Grand Forks area, following this storm also restricted restoration efforts. Some customers were without electric service as long as nine days, 20 hours. An assessment of the damage to the system in most areas could not be initiated until Monday, April 7, when the storm subsided. Without the help of neighboring companies (Manitoba Hydro, Minnesota Power, and Northern States Power Company) providing linemen and equipment, the duration of the outages and restoration of the lines would have been much longer.

The impacted systems (Minnkota Power Cooperative, Inc., Montana-Dakota Utilities, Northern States Power, Otter Tail Power, United Power Association, and Western Area Power Administration) coordinated the restoration effectively via twice-daily conference calls immediately after the disturbance. The purpose of the calls was to review the status of the system and prioritize the focus of the restoration effort. Initially, restoration of the high-voltage transmission into Grand Forks was targeted to correct the voltage problems and restore electric service to the area's customers.

In an effort to provide more reliable service and reduce the operation of gas turbine generators, which were providing electric service to Jamestown, North Dakota customers, a temporary tap on the Jamestown–Carrington 115 kV line was made to the Center–Jamestown 345 kV line west of Jamestown. The line was opened behind the tap and operated at 115 kV into Jamestown. A 115 kV relay panel was installed, and the line was reconnected to the 115 kV tap of the Jamestown transformer.

The local generation available in several areas was very beneficial during the disturbance. Several other utilities would have benefited by having large portable generating units available for use during the disturbance. However, some local generation that had been removed in the past would have been useful during the disturbance.

## Problems and Recommendations

### Communications

Several utilities lost communications to SCADA remote terminal units during the storm. The prevalent problem was loss of communications caused by backup batteries running down due to the long duration of ac power outages and failure of backup generators. The severity of the storm closed roads and reduced visibility to zero, preventing maintenance personnel from reaching the sites to install portable generators or start backup generators that did not automatically start.

The affected systems should analyze all communication failures and correct any problems with backup generators, increase the capacity of backup batteries at key communication repeater sites, and take any other steps necessary to prevent the widespread communication failures that occurred during this disturbance.

Refer to: NERC Operating Policy 7 — Telecommunications, A. Facilities

### Studies

The lack of a current model and analysis tool at the MAPP Center delayed system studies to determine new export limits for the North Dakota area.

The MAPP Center should keep the northern MAPP study package online and a current power flow model available to provide timely analysis of system outages not covered by published operating guides when requested by member systems. The northern MAPP power flow and stability study package should be improved to allow more flexibility to model various unusual conditions. Procedures should be developed to ensure achieving model solutions for multiple prior outage conditions and to improve the modeling of customer demand during actual disturbance events to ensure study results are accurate and not overly conservative.

Refer to: NERC Operating Policy 6 — Operations Planning, B. Emergency Operations

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III, Transmission, Guides, B. Security

### Protective Relay Misoperations

The utilities should investigate suspected relay misoperations and provide a brief report describing the problems and the steps taken to correct the relay misoperations that occurred during the disturbance.

Refer to: NERC Operating Policy 4 — System Coordination, D. System Protection Coordination

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III, Transmission, Guides, D. Protection Systems

### Public Appeals for Reduced Demand

The governor of North Dakota made a public appeal on April 7, 1997, to reduce electrical use because of the weakened system. The appeal was successful in reducing demand and prevented additional system problems in many areas. However, customers also reduced demand unnecessarily in areas that were not impacted by the storm.

The decision to request the public to reduce demand should be coordinated and agreed upon between all systems prior to its implementation. The public appeal should be targeted to specific systems that are weakened to the point that they cannot serve their electrical demands. The duration of the request should also be clearly defined, and a method to rescind the public appeal should be developed.

Refer to: NERC Operating Policy 5 — Emergency Operations, A. Coordination With Other Systems

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, II, Resources, Guides, B. Demand-Side Resources

### Radio Communications Interference

Radio communications was interfered by outside utility crews that had truck-to-truck radio frequencies that were the same as the host utility's radio repeater.

It is recommended that an emergency channel be available on all system maintenance trucks so when they are working in another service territory they can avoid interfering with the repeaters.

Refer to: NERC Operating Policy 6 — Operations Planning, B. Emergency Operations, Guide 3.1, Communications

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, II, Resources, Guides, C. Supply-Side Resources

### Outage Reporting

The reporting of the 115 kV Donaldson-Warsaw line outage to MAPP, which occurred on April 5, 1997, was overlooked until April 12, 1997.

It is recommended that the utilities review the MAPP reporting requirements to ensure all outages are reported in the future.

Refer to: NERC Operating Policy 5 — Emergency Operations, A. Coordination With Other Systems

### Review of Transmission Design

The number of structures lost on some transmission lines was largely due to an insufficient number of dead-end type structures.

It is recommended that specific critical transmission lines be reviewed by the appropriate utilities to determine whether additional dead-end type structures should be installed to minimize possible future damage.

Refer to: *NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, II, Resources, Guides, B. Demand-Side Resources

For more information on this disturbance, please contact the Mid-Continent Area Power Pool.

## 2. Minnesota-Wisconsin Interface Separation — June 11, 1997

### Summary

A section of a 345 kV transmission line (King-Eau Claire-Arpin-Rocky Run-North Appleton) opened on June 11, at 0006 CDT during a significant scheduled transfer of electricity from west to east. The initial electricity flow condition in the region was due to large transfers from west to east (1,349 MW) and north to south (2,107 MW). The transmission line loads were about 50% of the peak values. System protection at Rocky Run incorrectly opened the circuit at an ampere level below its setting, possibly due to a large dc offset in current on the line. The line opening and reclosure at Rocky Run plus the line opening at Arpin led to a sudden decrease, increase, and finally stoppage of electricity flow from Eau Claire to Arpin. This line loss resulted in low voltages in the southeastern part of the region, heavy loading of parallel, lower-voltage transmission systems, and a large phase angle across the open tie at Arpin.

When the Rocky Run breaker opened, additional loading occurred on the already heavily loaded 345 kV lines exporting schedules from north to south. These loading conditions were near system protection limits and triggered overloading alarms at a nuclear plant located in the area.

Redispatch of generation — ramping up generation connected to the eastern portion of the transmission line, and ramping down generation connected to the western portion of the transmission line — was necessary to correct these conditions and to permit reclosing the open line. Relay settings at Rocky Run and Arpin were increased on June 13 to avoid future unexpected line openings at values less than the line ratings. Also, guides were developed to permit faster generation rescheduling to reduce the time required to reclose the interconnection should it reopen.

### Predisturbance Conditions

During the evening of June 10 and early on June 11, power flows in MAPP on major tie lines into the MAIN and SPP Regions were at extreme line loading conditions. MAPP regional demand levels were low (about 50% of peak values) and a significant amount of generation was off line in MAIN — about 6,975 MW of generating capacity was out of service due to maintenance, Nuclear Regulatory Commission restrictions, or other unit problems. The total interchange schedules from west to east were about 1,349 MW.

MAIN also was exporting about 2,130 MW. Of this amount, 1,955 MW was flowing east. The 880 MW of flow to TVA included 600 MW from Electric Energy, Inc., generation located in MAIN for nearby uranium processing facilities.

The SPP Region had large generating units off line for maintenance including units at La Cygne and Iatan. Exports from north to south were 2,107 MW. SPP also was importing 175 MW from MAIN (east to west).

During the late afternoon of June 10, power flows across the 345 kV King-Eau Claire-Arpin-Rocky Run-North Appleton transmission line reached levels that concerned Northern States Power Company (NSP). The line flow reached 945 MW, and the Eau Claire bus voltage dropped to 340 kV. As a result, NSP requested that the regional reliability coordinator collect interchange schedules in preparation for implementing line loading relief. Schedules were collected, but the line loading relief was not implemented because the line loading decreased after the interchange schedule data was collected. When the loading level dropped to approximately 850 MW, NSP released the line loading relief request (about 1930 CDT).

As the evening progressed, north-south and inter-region flows continued to increase. Nebraska Public Power District (NPPD) monitored the Cooper south flow as it approached and eventually exceeded the

interface's 1,100 MW operating limit. At 2220, NPPD contacted Omaha Public Power District (OPPD) to verify the 1,124 MW Cooper south flow value, and asked about planned mitigation measures. OPPD indicated it was going to reduce generation at its Nebraska City plant.

Cooper south flow continued to rise, reaching 1,202 MW at 2300. Also, the Eau Claire 345 kV voltage again declined to 340 kV, prompting NSP to again call for line loading relief schedule collection at 2315. At 2320, OPPD reported to the regional reliability coordinator that the Cooper south flow was at 1,280 MW and it also called for line loading relief schedule collection. While schedules were being collected and before the reliability coordinator invoked line loading relief, the Cooper south flow increased to 1,300 MW and stayed at that level during the next half hour. The Cooper south flow increased to 1,347 MW at midnight and OPPD called for the MAPP line loading relief process to be invoked.

At about 0006 on June 11, large electricity transfers occurred from west to east and from north to south. No major transmission lines were out of service in the west-east area of concern and 880 MVA flowed on the 345 kV Eau Claire-Arpin line. Because of its geographical location, this line carries a large share of the transfer west to east inter-regionally. Voltages along the line were very low (326 kV at Arpin and 327 kV at Rocky Run) prior to the Rocky Run breaker opening.

### Description of the Disturbance and Sequence of Events

At the time of the event, (0006:05 on June 11) significant transmission loading changes occurred in two areas: the east-west interface and the north-south interface.

### East-West Interface

Just prior to 0006:05, the Eau Claire-Arpin line section was carrying 880 MVA due to large transfers from west to east causing very low voltage levels at Arpin and Rocky Run (326 kV and 327 kV, respectively).

At 0006:05, phase comparison relays at Rocky Run operated due to the large electricity flow and unbalanced current and caused two Rocky Run breakers to open, interrupting transmission line flow. Resulting momentary high voltage at Eau Claire caused 161 kV capacitor banks at the substation to automatically be removed from service.

At trip time plus 2.5 seconds, one Rocky Run breaker automatically reclosed, but the other breaker remained open. Upon reclosure, the monitored line load went to 1,020 MVA on the Eau Claire-Arpin line. Current measured at Rocky Run was 1,920 amperes with a significant dc offset. (A dc-offset current superimposed on the ac current can occur at the time of breaker closing.)

Three cycles later, two breakers at Arpin opened on primary and secondary high-set, phase-over-current relays for the line towards Eau Claire. The transient overreach characteristics of these relays responded to the line-load current, which had a dc offset. An angle greater than 97 degrees was recorded across the open Arpin breakers soon after they opened. The Rocky Run breaker opened again at the same time as Arpin due to its close-into-fault logic sensing the heavy line-load flow.

At 0023:13, the two open breakers were closed at Rocky Run for the line towards Arpin by remote control. Voltage levels improved as generation in Wisconsin increased.

At 0208:13 the angle across the open Arpin breakers was reduced to 57 degrees by increasing generation to the east and reducing generation to the west

The breakers at Arpin were closed just after 0208:13.

The relays at Arpin and Rocky Run were reset on June 13 and the Rocky Run auto reclosing was disabled on June 25. Post disturbance functional relay tests at Arpin and Rocky Run found all system protection schemes working properly. The Rocky Run relaying phase angle comparison blocking setting for the line toward Arpin was raised. The close-into-fault relay setting at Rocky Run also was raised. The Arpin primary and secondary relay systems pickup for the line towards Eau Claire was raised to accommodate the dc offset and transient overreach.

The Minnesota-Wisconsin Phase Angle Committee, which was formed after this event, published a report on this incident, implemented load restrictions and developed a plan to reduce the phase angle should the Minnesota-Wisconsin interface open again. These loading limits, called the Arpin Loading Guide, were established for the interface as measured at Arpin and are based on the low voltages experienced during high loading. The phase angle increases after the Minnesota-Wisconsin 345 kV line opens because the transfers are shifted to the lower voltage, higher impedance transmission systems between regions. Closing the Eau Claire-Arpin line with greater than 60 degrees phase angle has caused problems with generators near the closing point.

The Minnesota-Wisconsin Phase Angle Committee established a loading level of 775 MW at Arpin as the point at which Wisconsin Power & Light (WPL) system operators tell MAIN to institute MAIN Guide 1C, which required collecting schedules and holding any additional schedules impacting the Eau Claire-Arpin line. MAIN, through Guide 1C, also notifies MAPP to collect and hold schedules that impact Eau Claire to Arpin. MAPP then declares a condition "yellow," which notifies members that the loading on a transmission line is higher than its normal limit.

At a loading level of 825 MVA, WPL informs MAIN to cut schedules to reduce the electricity flow on the Eau Claire-Arpin line to 800 MW.

Since June 11, 1997, flows on the Eau Claire-Arpin line have required using the Arpin Loading Guide almost every day through August 26, 1997. Experience has shown that these loading limits are appropriate. The following problems have occurred occasionally while trying to meet these limits:

1. Low voltage occurred at Arpin during heavy 345 kV line flows. The voltage level was improved when WPL installed a capacitor bank at Arpin on June 30.

2. Automatic opening of the 69 kV Dairyland Power Cooperative (DPC)-WPL ties at Council Creek and Hilltop.

3. Flows ramp up quickly with 30 MW increases at any time and with larger increases or decreases during schedule changes at 0000, 0600, and 2200 hours.

Kewaunee No. 1 and Point Beach No. 2 are now in service in MAIN to the east of the critical interface. The Regions expect that the phase angle between west and east will be reduced when Point Beach No. 1 is at full power.

Dynamic studies will be completed near the start of 1998 and replacement of relays, expected after the 1998 summer peak, will be required before the Arpin loading guides are increased.

### North-South Interface

At about six minutes after midnight, 0006 hours on June 11, with the path from west to east open and the resulting high phase angle not allowing immediate reclosure, a significant change occurred to the electricity flows on the north-south interface. The opening of the Arpin-Rocky Run line resulted in the 345 kV Cooper south line flow to increase from about 1,300 MW to 1,554 MW and the 345 kV Cooper-St. Joseph line flow to reach 884 MW. This rise in line flow resulted in the combustion turbines and

associated metering at St. Joseph to be over-driven and triggered overload alarms at NPPD's Cooper substation. Also, low voltages in the eastern Iowa area prompted Midwest Energy Company (MEC) to bring on combustion turbines for voltage support. Regional line loading relief cuts, made as a result of the midnight request by OPPD, were made across the half hour and the Cooper south flow was reduced to 1,210 MW by 0100. Schedule cuts continued to reduce the Cooper south flow to 1,054 MW by 0130. The Eau Claire-Arpin line was returned to service shortly after 0200, and the Cooper south flows dropped to levels where the line loading relief could be canceled.

Following the June 10 heavy loading and June 11 incident, a model was developed by OPPD to simulate the conditions that occurred. The power flow model indicated numerous overloads on the 345 kV and 161 kV ties west to east and north to south. The major concern centered on the trip setting on the 345 kV Cooper-St. Joseph line. The protective relay settings on the Cooper-St. Joseph line are such that power flows in excess of 900 MW infringe on the relay characteristics and operation is possible, depending on the simultaneous var flows on the line. Because the recorded flow was close to the relay setting, a power flow simulation of the loss of the Cooper-St. Joseph line was developed to evaluate the impact on the remaining transmission system.

The simulation indicated that if the Cooper-St. Joseph line opened, essentially all remaining 345 kV and 161 kV ties from north to south and west to east would have been overloaded to levels that could have resulted in relay operations and resulting line openings on those facilities. Specifically, the simulation showed 1,225 MW on the Cooper-Fairport line, which could open for flows exceeding 800 MW. It is conceivable that MAPP would have separated from its neighboring regions. Following such tie-line actions, the MAPP Region could have experienced loss of generation due to over frequency. Under frequency load shedding in the adjacent regions also might have occurred.

### Conclusions and Recommendations

The 345 kV west to east transmission system was heavily loaded, and the loss of a major transmission element in the east required system operator action to restore the system to an acceptable operating condition.

Large power transfers from west to east due to generation outages in the east can cause a phase angle of as much as 100 degrees across the open interconnection for loss of the Eau Claire-Arpin 345 kV line. This phase angle difference must be reduced by rescheduling generation before the interconnection can be reclosed. About 650 MW of schedule changes are needed to reduce the angle to about 60 degrees to permit reclosing the interconnection. Loading limits have been established for the Eau Claire-Arpin-Rocky Run line to permit safe operation of the MAPP and MAIN systems. Dynamic stability studies must be completed and relays must be replaced before loading guide limits are increased.

With large electricity transfers from west to east and north to south, loss of the Eau Clair-Arpin-Rocky Run line resulted in overload alarms on transmission lines in the south.

Although the incident resulted in heavily loaded lines when the Rocky Run breaker opened and required rescheduling generation to reclose the breaker, no customers were without electric service. Load-flow simulations following the event showed that the loss of the 345 kV Cooper-St. Joseph line, which was approaching its relay setting limits, could have subsequently resulted in the line opening.

### Conclusion

Due to the large amount of unavailable generation in Wisconsin and Illinois, the level of electricity transfers on June 11 from west to east resulted in unacceptable system conditions upon the loss of the 345 kV Arpin-Rocky Run line.

### Recommendation

Examine transfer limits and adjust or design operating procedures for restoring the system following a disturbance when it is known that large quantities of generation will be out of service in the area.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations

NERC Operating Policy 3 — Interchange, A. Interchange

NERC Operating Policy 3 — Interchange, B. Interchange Schedules

NERC Operating Policy 3 — Interchange, E. Transfer Capability

NERC Operating Policy 5 — Emergency Operations, C. Transmission Overload

NERC Operating Policy 6 — Operations Planning, B. Emergency Operations, Requirements 1, 2, & 3

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III, Transmission, Guides, A. Adequacy

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III, Transmission, Guides, B. Security

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III, Transmission, Guides, C. Coordination

### Conclusion

The relays at Rocky Run opened the Rocky Run breaker at a lower level than anticipated.

### Recommendation

System protection schemes should be reviewed when system changes result in increased line loadings that approach equipment ratings.

Refer to: NERC Operating Policy 4 — System Coordination, D. System Protection Coordination

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III, Transmission, Guides, D. Protection Systems

For more information on this disturbance, please contact the Mid-America Interconnected Network or Mid-Continent Area Power Pool.

## 3. Potomac Electric Power Company Disturbance — June 20, 1997

### Summary

A capacitor mounted on the "B" phase bushing of 230 kV breaker 4C at Substation 202 failed and destroyed the breaker on Friday, June 20, at 2027 EDT. The resulting three-phase fault was cleared in 3.5 cycles by the opening of the three appropriate breakers at Substation 202 and one breaker at Generating Station 130 (Figure 1). However, at the same time that the fault cleared, the number one set of relays on the 23106 and 23107 circuits at the Substation 84 initiated signals to open the four 69 kV breakers on each transformer secondary at Generating Station 101 switchyard. This operation separated Generating Station 101, its switchyard, and the demand supplied from the switchyard from the local transmission system creating an island. At the time of the islanding, Generating Station 101 output was at about 482 MW (five coal-fired steam units) with a connected demand of about 350 MW. As a result of the excess generation, the island frequency increased to a maximum 61.89 Hertz. The steam/governor controls of all five generators responded to the overfrequency condition and automatically started to reduce generation by lowering the steam flow from the boilers. Then, each unit successively was removed from service due to several unit protection device problems. The events occurred in about two and a half minutes, resulting in the interruption of service to about 18,000 customers at 2029 EDT. Initial service was restored in forty-seven minutes and was completely restored by 2145.

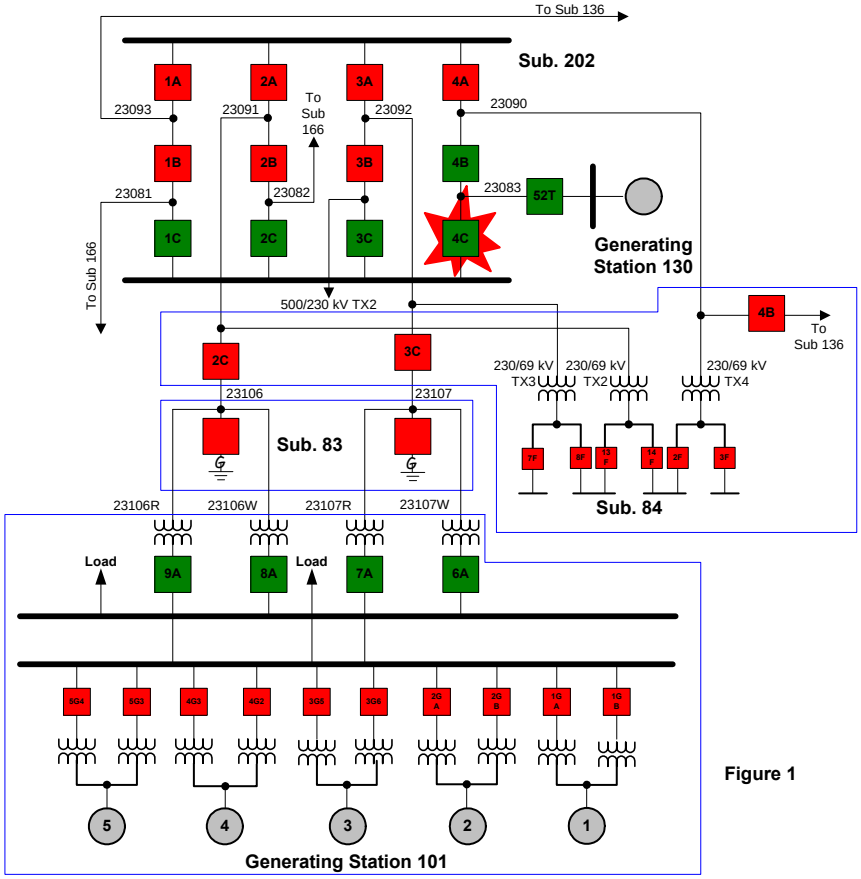



Figure 1

### Disturbance Sequence Of Events

| Time | Event |
|---|---|
| 2027:38 | 230 kV Breaker 4C at Substation 202 failed catastrophically due to a rupture of the breaker tank. This rupture was caused by the failure of a capacitor mounted on the "B" phase bushing of the breaker. The fault was cleared in 3.5 Hz by system protection opening 230 kV Breakers No. 1C, 2C, 3C, and 4B at Substation 202 and 230 kV Breaker No. 52T at Generating Station 130. 69 kV Breakers No. 6A, 7A, 8A, and 9A in Generating Station 101 opened as a result of a misoperation of Transfer Trip No. 1 received from Substation 84 on underground 230 kV Feeders No. 23106 and 23107. This misoperation was due to a specific set of conditions involving a zero-voltage, external three-phase fault followed by reverse flowing cable charging. These breaker operations islanded Generating Station 101 with all five generators online supplying the local area demand. At this time, generation was about 482 MW and the local area demand was about 350 MW. The system frequency rose to 61.89 Hz. |
| 2027:50 | Generating Station 101 Unit 5 steam valves closed and fuel shut off causing the unit output to go to 0 MW. The fuel trip was initiated by the slow response of the main governor pilot valve, allowing the control valves to close enough so that the no-load switch was activated shutting off the boiler fuel. An investigation demonstrated the main governor pilot valve contained a defective component that caused a significant reduction in the pilot valve's control responsiveness. |
| 2028:02 | Generating Station 101 Unit 3 was removed from service due to the generator's loss of field relay operation. This loss was due to the exciter motor over-speed protection switch on Unit 3 prematurely operating, opening the exciter breaker. |
| 2028:47 | Generating Station 101 Unit 2 was removed from service due to the generator's loss of field relay operation. This loss was due to a defective loss-of-field relay, which operated at MW and MVAr levels above the unit's under-excited, reactive ampere limit that would not have normally initiated a removal from service. |
| 2028:55 | Under-frequency relays set at 59.3 Hz operated to shed about 16 MW of local area demand. |
| 2029:15 | Under-frequency relays set at 58.9 Hz operated to shed about 6 MW of local area demand. |
| 2029:50 | Generating Station 101 Unit 4 was removed from service due to the generator's under-frequency relay operation. At this point, the Potomac River area demand exceeded the available generating capacity of the remaining units. |
| 2030:00 | Generating Station 101 Unit 1 was removed from service due to the generator's under-frequency relay operation. At this point, the Potomac River area demand exceeded the available generating capacity of the remaining units. |
| 2030:11 | Generating Station 101 Unit 5 was removed from service by the operator because fuel was shut off and the unit could not supply the area demand. At this point, Generating Station 101 is completely de-energized and, as a result, no electricity was available to supply the islanded area that Generating Station 101 switchyard was serving. |
| 2053:06 | 230 kV feeder 23107 was energized from the Substation 84 into Substation 101 |

switchyard.

2115:36 Restoration of customer demand begins.

2135:00 230 kV Feeder 23106 was energized from the Substation 84 into Generation Station 101 switchyard.

2145:00 All customer demand is restored.

### Conclusions

The following conclusions are excerpts from a June 20, 1997, Outage Investigation Final Report completed by the utility involved:

- The method and appropriateness of attaching capacitors to circuit breakers need to be reviewed.
- Transmission line relays should be simulation tested before being approved for use on the electric system.
- The procedures for ensuring the proper calibration and operation of the Generating Station 101 protective devices and controls need to be reviewed.

### Recommendations

As a result of a thorough investigation into this disturbance, the utility involved made four major recommendations, which are excerpts from its final report:

1. Investigate alternatives to providing capacitance for breaker interrupting rating for short-line faults to the 230 kV breaker at Substation 202 without installing capacitors in such a way as to place the breaker at risk.

   Refer to: *NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III. Transmission, Guides, A. Adequacy

2. Upgrade the transmission line relays at Substation 84 and Generating Station 101 switchyard and simulation test them to ensure they do not operate for the conditions leading to this incident.

   Refer to: NERC Operating Policy 4 — System Coordination, D. System Protection Coordination, Guide 2. Protection system implementation, operation, and maintenance and Guide 3. Reviewing abnormal operation.

   *NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III. Transmission, Guides, D. Protection Systems

3. Test and calibrate for proper operation the generating unit turbine-generator speed and load control devices and all exciter-motor over-speed switches. Repair the main governor pilot valve on Unit 5. Test the coordination of the loss-of-field relays with each generating unit's Under-excited Reactive Ampere Limit (URAL) and replace the loss-of-field relay on Unit 2 that was determined to be defective. Provide control system modifications, which were identified during the investigation that would further enhance the units' ability to respond to island conditions.

   Refer to: NERC Operating Policy 4 — System Coordination, D. System Protection

Coordination, Guide 2. Protection system implementation, operation, and maintenance and 2.4 Testing and maintenance, and Guide 3. Reviewing abnormal operation.

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, or Planning Reliable Bulk Electric Systems*, II. Resources, Guides, A. General.

4. Review and revise as necessary Generating Station 101 Operations and Maintenance Procedures to incorporate lessons learned and address specific actions related to Recommendation No. 3. Provide additional training for the Generating Station 101 operators concerning reactive power, voltage, load and islanding operation, and restoration.

   Refer to: NERC Operating Policy 5 — Emergency Operations, D. Separation from the interconnection.

   NERC Operating Policy 8 — Operating Personnel and Training, C. Training.

For more information on this disturbance, please contact the MAAC regional reliability council office.

## 4. 230 kV Line Reactor Failure in the Western Interconnection — August 26, 1997

### Summary

At about 0109:03 MST on August 26, 1997, system protection opened the Station A terminal of the Station T-Station A 230 kV transmission line due to an internal failure in the 230 kV line reactor at Station A. The reactor circuit switcher opened properly and the control area's system dispatcher closed the line at Station A by SCADA control. Operating personnel en route to Station A observed a fire and requested that the control area system dispatcher de-energize the Station T-Station A 230 kV line for safety.

At 0121:54 MST, the Station T-Station A 230 kV line was de-energized. However, the oil fire continued to burn. At 0137:34 MST, the fire burned down one phase of the de-energized line, which fell into the 230 kV bus between breakers A and B. This resulted in a three-phase fault on the ring bus, which is also the high side of the 230/161 kV autotransformer. Breaker 161-C on the autotransformer failed to open resulting in system protection opening numerous 161 and 100 kV lines out of Station A and surrounding substations.

As a result of this disturbance, system protection removed from service 1,030 MW of area generation at one generating station by acceleration trend relay (ATR) action, and another 18 MW of generation at another nearby generating station. System frequency dropped to 59.81 Hz. At 0137:49, another 890 MW of generation was removed from service at two additional generating units. At 0138:58, an additional 20 MW of local generation was removed from service by system protection when a generator step-up circuit switcher opened. Because of the incident, about 7,200 electric customers (20 MW) were interrupted from about 15 minutes to three hours.

The control area's System Operations Control Center (SOCC) was also without electric service, and the SOCC activated its internal emergency generator at 0137. At 0138:21, the SOCC emergency generator failed. A fault to the transformer feeding the industrial park where the SOCC is located caused a loss of frequency source to the SOCC 51 seconds later, and the SOCC dispatcher failed to put AGC into flat tie-line bias mode. During the period from 0140 to 0158, some communications equipment at the SOCC failed due to loss of communications battery and backup uninterruptible power supply equipment. The battery alarms failed to let dispatchers know that the battery was low due to failure of the communications monitoring system, caused by the emergency generator failure. At 0204, the SOCC computer systems were running. However, there were no communications to the computers because the communications battery failed due to problems with the battery charger.

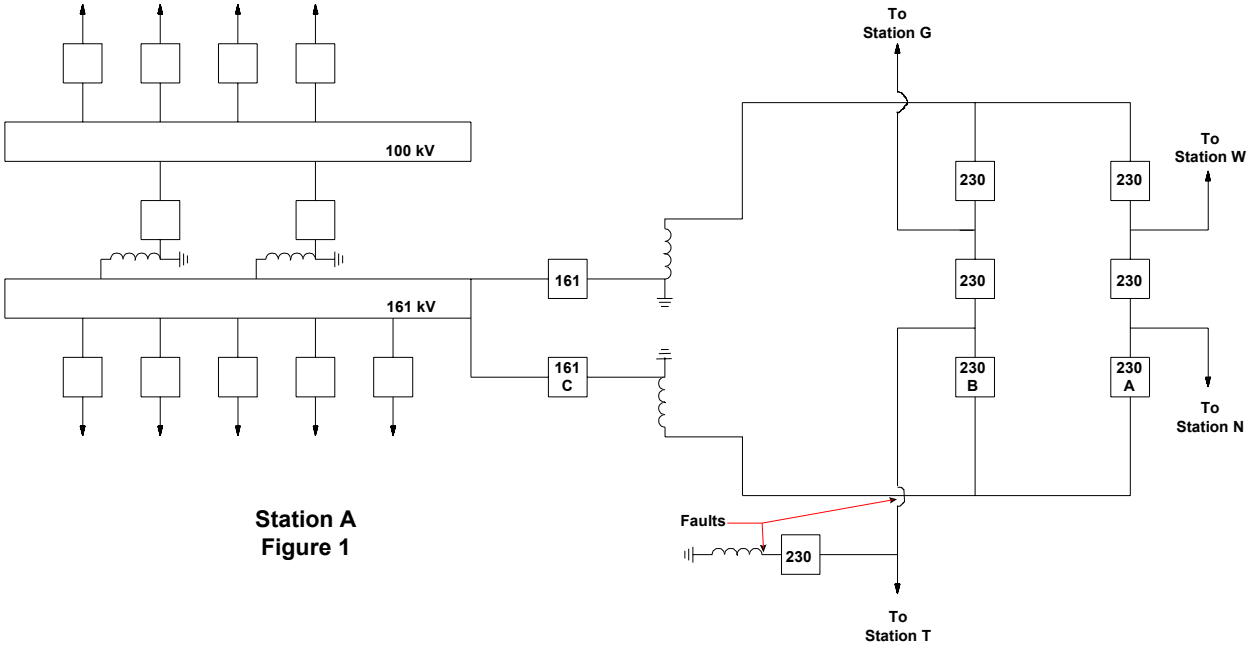
At this point, the SOCC SCADA system was still functioning. However, the dispatcher had no frequency source, no communications input to the system, and was experiencing a significant system disturbance including loss of demand and numerous generating units.

The area control error (ACE) recovered at 0317, one hour, 39 minutes later, and frequency control was placed on flat tie-line bias control. Most transmission lines were in service by 0200 along with restoration of most customers.

It was subsequently determined that during recent relay additions and modifications at Station A, the dc source was inadvertently tied to the 230 kV reactor source. This wiring error prevented circuit breaker 161-C from opening for the 230 kV bus fault. The major failure that occurred in the protection system was the incorrect wiring of the differential circuit and the breaker failure relaying, which was tied to the reactor dc source. The reactor fire shorted out the dc source, opened the dc circuit breaker in the control house, and disabled the breaker failure protection.

The failure of the SOCC emergency generator was never conclusively determined. The generator had been test-run prior to this event and no failures occurred. However, it was suspected that control components might have been damaged during a lightning storm in July and subsequently failed during the emergency conditions.

The 230 kV line reactor failure was due to an apparent internal flashover in the bushing pocket of the reactor tank resulting in failure and subsequent fire.




**Station A**
**Figure 1**

## Conclusions and Recommendations

As a result of this disturbance, seven conclusions and six recommendations were made. Two of these conclusions and recommendations are discussed below.

### Conclusion

1. The event was triggered by the failure of the 230 kV reactor and associated fire. However, incorrect wiring of the new differential and breaker failure relaying caused this extended event. During relay additions and modifications at Station A, the dc source was inadvertently connected to the reactor dc source. This wiring error prevented circuit breaker C from opening for the 230 kV fault. Had the relay protection worked as designed, this event would have lasted a few milliseconds and resulted in loss of only two generating units by ATR.

### Recommendation

The control area should review and consider changing relay test procedures to ensure that relay additions, and modifications are working properly prior to putting equipment in service.

Refer to: NERC Operating Policy 4 — System Protection, D. System Protection Coordination, Guide 2

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III. Transmission, Guides, D. Protection Systems

### Conclusion

2. The control area did not take timely corrective action to return ACE to zero and to recognize that the frequency source had been lost.

### Recommendation

The control area should verify that transmission operators respond appropriately to ACE and to loss of a frequency source.

Refer to: NERC Operating Policy 1 — Generation Control and Performance, E. Control Performance, Standard, 2.1

NERC Operating Policy 4 — System Coordination, A. Monitoring System Conditions, Guide 3.1

NERC Operating Policy 8 — Operating Personnel and Training, C. Training

The other conclusions and recommendations dealt with correcting problems with the communication battery-charger equipment, reviewing the backup power sources to SOCC and determining the adequacy of these sources including the backup generator, and determining why the Station T terminal of the Station T-Station A 230 kV line did not open when the reactor fault occurred.

Refer to: NERC Operating Policy 1 — Generation Control and Performance, B, Automatic Generation Control, Guide 3

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III. Transmission, Guides, D. Protection Systems

For more information on this disturbance, please contact the Western Electricity Coordinating Council (formerly the Western Systems Coordination Council).

## 5. Islanding of Generating Station X in the Western Interconnection — September 21, 1997

### Summary

System protection opened the 345 kV Station Z-Generating Station X (Station X) line at both terminals due to a B-phase-to-ground fault on Sunday September 21, 1997, at 23:10:40 MAST. Light rain was reported in the area at the time. The line is equipped with permissive reclosing at the Station Z end only to allow for one reclose following a phase-to-ground fault. This reclosing did not operate nor did it contribute to the event because of an excessive phase angle on the line at Station X. Due to a failed relay component, the 230 kV Station U-Station Y line opened only at Station Y, 36 cycles after system protection opened the 345 kV line. This line has reclosing at Station Y, but reclosing was blocked also due to an excessive phase angle.

Prior to the 345 kV line opening, Station X units Nos. 2 & 3 (550 MW each) were carrying a combined demand of 1,073 MW. With the loss of the Station Z-Station X line, most of the Station X electricity flowed on the 345 kV Station X-Station Y line into the southern area. This path at Station Y provides for power flow from the 345 to the 230 kV systems into Utility C's service area through the 230 kV Station U line. When the Station U-Station Y line opened, power flow was distributed through the parallel 230 and 115 kV systems in the eastern area. The heavy loading on the parallel system caused system voltages to decay rapidly with 345 kV line voltages dropping from 355 kV to 333 kV and 230 kV from 237 kV to 222 kV. About 20.5 MW of voltage sensitive demand was dropped in the central area.

System dispatchers at Utility A, Utility B, and Utility C began removing shunt reactors from service and switching in shunt capacitors to restore system voltages. About 277 MVARs of reactive capacity was switched out and 124 MVARs of capacitors switched into service. Voltages quickly responded and returned to pre-disturbance levels over the next 20 minutes.

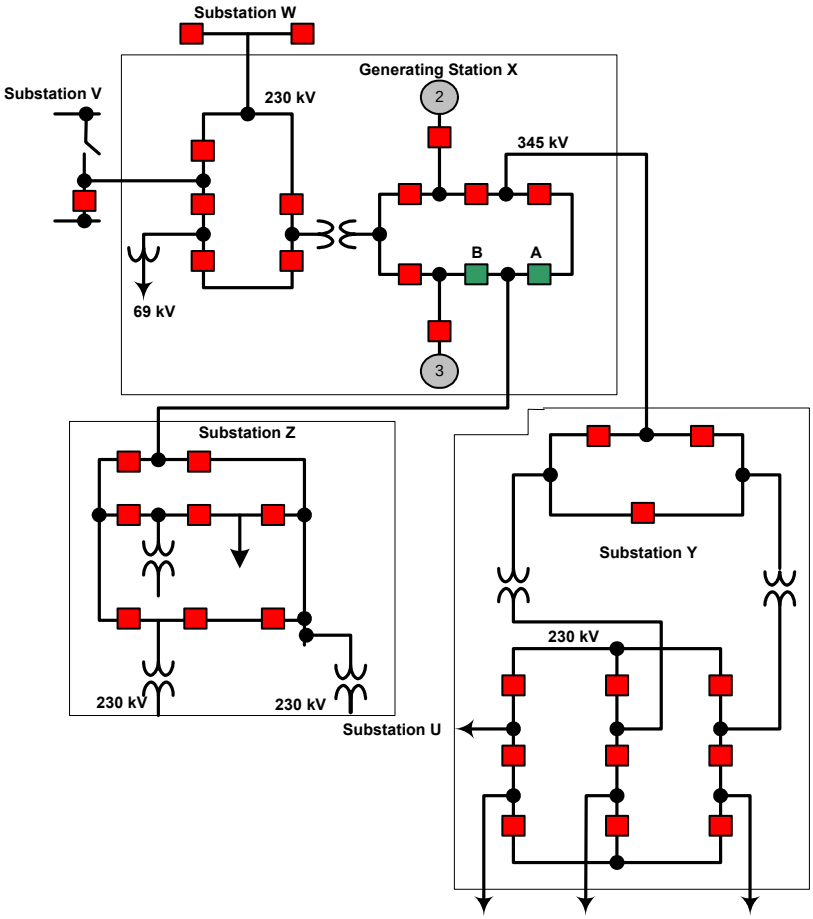
During this time, Utility A dispatchers attempted to restore the Station Z-Station X line by closing the Station Z terminal line circuit breaker. The line tested "good," however, the phase-angle indication at Station X was 110 degrees. This angle was later determined to be an incorrect value due to a scaling factor error in the SCADA database. At the same time, the Utility B and Utility C dispatchers attempted to close the Station Y terminal of the Station U line. These efforts failed due to an excessive phase angle at Station Y. The Utility A dispatcher opened the Station Z terminal and closed the Station X terminal, with only one circuit breaker (circuit breaker "A" in a ring bus configuration) energizing the line to Station Z. Utility A also adjusted generation and load north and south of the open line to decrease the phase angle at Station Z.

The Station Z terminal was closed with a phase-angle reading of 45 degrees at 2331:48:66. Two cycles of well-damped oscillations were observed following the closure, and the system voltage throughout the northeastern area began to rise. 18.9 seconds after making parallel, the Station Y 345 kV bus voltage reached 108% of nominal, initiating over-voltage tripping of the 345 kV Station X-Station Y line. System dispatchers had returned only one 24 MVAr reactor to service and all 124 MVARs of shunt capacitors switched after the 2310:40 event remained in service. System voltages reached 377 kV and 253 kV prior to the over-voltage tripping of the Station X-Station Y line. With circuit breaker "B" at Station X open, the Station Z-Station X line was energized to the bus only at Station X, and the two Station X generating units were now sending electricity (964 MW) through the 345/230 kV transformer (600 MVA rating) into the 230 kV system at Station X (two lines). System protection opened both the Station X-Station V and Station X-Station W lines, due to the resulting power swing. Both Station X generating units were removed from service, momentarily removing the Station X generating station from the bulk electric system and 9 MW of 69 kV demand supplied from the Station X 230/69 kV substation. About one second after the second generating unit was removed from service, the Utility A dispatcher closed circuit breaker "B" via SCADA action, thereby picking up the 69 kV demand and Station X station

service. The Utility A dispatcher closed circuit breaker "B" following the successful closure of the Station Z terminal breaker, restoring the line to service.

Circuit breakers at two substation transformers (230/115 kV) in the eastern area opened on over-voltage, but no demands were shed due to the loop 115 kV system. System operators tried to bring electricity in from the Eastern Interconnection (MAPP) through two HVDC ties. However, one HVDC tie would not respond to ramp commands from the Utility B dispatcher due to numerous major alarms caused by the system disturbance, and the other HVDC tie failed to ramp until the third command. Once the second HVDC facility was ramping, transmission line loading problems on the eastern side of the tie (MAPP) forced the tie to be ramped to zero flow.

System restoration began at 2333:07 and was completed at 2356. The Station X generating units returned to service the next day and customers were restored.



### Conclusions and Recommendations

As an outcome of this event, nine conclusions and seven recommendations were made. The most significant being that the utilities should:

- Determine and correct the cause of the relay failure at Substation Y,
- Perform studies to simulate system conditions prior to and during the event,
- Study the possibility of installing automatic reactor and capacitor switching at specific locations to assist dispatchers during abnormal voltage conditions,
- Revise dispatcher orders regarding line restorations to avoid the possibility of isolating a line to a bus section at Generating Station X,
- Correct the phase-angle indications at Generating Station X on the Substation Z line, and
- Determine if over-voltage relay settings at Substation Y are consistent with other over voltage settings.

Refer to:

NERC Operating Policy 2. —Transmission, A. Transmission Operations, Requirement 3, Studies

NERC Operating Policy 2. — Transmission, B. Voltage and Reactive Control, Requirements 1

NERC Operating Policy 4. — System Coordination, D. System Protection Coordination, Guide 2, Protection system implementation, operation, and maintenance and Guide 3, Reviewing abnormal operation

NERC Operating Policy 8. — Operating Personnel and Training, C. Training

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III. Transmission, Guides, A. Adequacy

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III. Transmission, Guides, B. Security

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III. Transmission, Guides, C. Coordination

*NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems*, III. Transmission, Guides, D. Protection Systems

For more information on this disturbance, please contact the Western Electricity Coordinating Council (formerly the Western Systems Coordination Council).

# Appendices

## Appendix A. Reporting Requirements for Major Electric Utility System Emergencies

NERC Operating Policy 5F and Appendix 5F detail the requirements and procedures for reporting disturbances or unusual occurrences that jeopardize the operation of the interconnected systems, and result, or could result, in system equipment damage or customer interruptions. Operating Policy 5F and Appendix 5F are included below for reference and guidance.

### Operating Policy 5.F. — Disturbance Reporting

#### *Introduction*

Disturbances or unusual occurrences that jeopardize the operation of the interconnected systems, and result, or could result, in system equipment damage or customer interruptions, must be studied in sufficient depth to increase industry knowledge of electrical interconnection mechanics to minimize the likelihood of similar events in the future. It is important that the facts surrounding a disturbance shall be made available to Security Coordinators, system and control area operators, system managers, regional councils, NERC, and regulatory agencies entitled to the information.

**Requirements**

**1.** **Regional council reporting procedures.** Each regional council shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.

**2.** **Analyzing disturbances.** Bulk system disturbances shall be promptly analyzed by the affected systems.

**3.** **Disturbance reports.** Based on the NERC and DOE disturbance reporting requirements, those systems responsible for investigating the incident shall provide a preliminary written report to their regional council and NERC.

**3.1.** **Preliminary written reports.** Either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Preliminary Disturbance Report form shall be submitted by the affected system(s) within 24 hours of the disturbance or unusual occurrence. Certain events (e.g., near misses) may not be identified until some time after they occur. Events such as these should be reported within 24 hours of being recognized.

**3.2.** **Preliminary reporting during adverse conditions.** Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Preliminary Disturbance Report within 24 hours. In such cases, the affected entity(ies) shall notify its regional council(s) and NERC promptly and verbally provide as much information as is available at that time. The affected utility(s) shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.

**3.3.** **Final written reports.** If in the judgment of the regional council, after consultation with the electric system(s) in which a disturbance occurred, a final report is required, the affected electric system(s) shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional council approval.

**4.** **Notifying NERC.** The NERC Disturbance Reporting Requirements, shown in **Appendix 5F**, are the minimum requirements for reporting disturbances, unusual occurrences, and voltage

excursions to NERC.

5. **Notifying DOE.** The U.S. Department of Energy's most recent Power System Emergency Reporting Procedures, shown in **Appendix 5F,** are the minimum requirements for U.S. utilities and other entities subject to Section 311 of the Federal Power Act required to report disturbances to DOE. Copies of these reports shall be submitted to NERC at the same time they are submitted to DOE.

6. **Assistance from NERC OC and the Disturbance Analysis Working Group (DAWG).** When a bulk system disturbance occurs, the regional council's OC and DAWG representatives shall make themselves available to the system or systems immediately affected to provide any needed assistance in the investigation and to assist in the preparation of a final report.

7. **Final report recommendations.** The regional council shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if regional council tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the regional council shall notify the NERC PC and OC of the status of the recommendation(s) and the steps the regional council has taken to accelerate implementation.

## A. NERC Disturbance Reporting Requirements

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, by a regional council, or power pool.)

### 1. Loss of Firm System Loads

1.1 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.

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

1.2.1. 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.

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

1.3. 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.

When to Report: The DOE EOC (202-586-8100) shall be notified as soon as practicable without undue interference with service restoration and, in any event, within three hours after the beginning of the interruption.

### 2. Voltage Reductions or Public Appeals

2.1. A report is 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.

2.2. A report is required for any issuance of a public appeal to reduce the use of electricity for purposes of maintaining the continuity of the bulk electric power system.

When to Report: The DOE EOC (202-586-8100) shall be notified as soon as practicable, but no later than 24 hours after initiation of the actions described in paragraph 2 above.

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

3.1. 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:

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

3.1.2. 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, county). This requirement is intended to include any major event involving the supply of bulk power.

3.2. 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.

When to Report: The DOE EOC (202-586-8100) 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.

### 4. Fuel Supply Emergencies

4.1. 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:

4.1.1. 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.

4.1.2. 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 bulk electric power supply.

When to Report: The DOE EOC (202-586-8100) shall be notified as soon as practicable, or no later than three days after the determination is made.

## Appendix B. Interruptions, Unusual Occurrences, Demand and Voltage Reductions, and Public Appeals

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

| Date | Region | Utilities | Type | MW | Customers | Cause |
|---|---|---|---|---|---|---|
| 01/09/97 | SERC | Duke Power Company | INT | 325 | 95,000 | Weather – Winter storm |
| 01/10/97 | NPCC | Consolidated Edison Company of New York, Inc. | UO | 300 | 0 | Equipment failure |
| 03/13–14/97 | ECAR | Consumers Energy and Detroit Edison Company | INT | 550 | 725,000 | Weather – Winter ice storm |
| **04/04–06/97** | **MAPP** | **Northern MAPP and Southern Manitoba** | **INT** | **564** | **128,000** | **Weather – Spring rain, ice, & snow storm** |
| 04/06/97 | ECAR | Consumers Energy | INT | 100 | 148,000 | Weather – Strong winds |
| 05/18/97 | ECAR | Northern Indiana Public Service Company, Inc. | INT, PA | 150 | 100,000 | Weather – Severe thunderstorm |
| 06/03/97 | WECC | Pacific Gas & Electric Company | INT | 3 | 2,000 | Vandalism |
| 06/06/97 | WECC | El Paso Electric Company | INT | 373 | 48,000 | Weather – Lightning suspected |
| 06/10/97 | NPCC | Hydro-Québec | UO | 3 | 0 | Human error |
| **06/11/97** | **MAPP MAIN** | **Eastern MAPP and Western MAIN Interface** | **UO** | **0** | **0** | **Equipment misoperation** |
| **06/20/97** | **MAAC** | **Potomac Electric Power Company** | **INT** | **350** | 18,000 | Equipment failure |
| 06/23/97 | MAIN | ComEd | INT | 800 | 5,300 | Equipment failure |
| 06/29/97 | WECC | WAPA-Lower Colorado Area | INT | 257 | 32,000 | Transmission line fault |
| 07/02/97 | ECAR | Detroit Edison Company | INT | 2,000 | 250,000 | Weather – Strong winds |
| 07/16/97 | ECAR | Consumers Energy | PA | N/A | N/A | Weather – High demand & purchase power contract canceled |
| 08/01/97 | SPP | Cajun Electric Power Cooperative, Inc. | UO | 0 | 0 | Unknown/suspected vandalism |
| 08/05/97 | WECC | Southern California Edison Company and Los Angeles Department of Water and Power | INT | 3,525 | 0 | Airplane accident |
| 08/13/97 | FRCC | Tallahassee Electric Department | INT | 280 | 45,000 | Transmission line fault |
| 08/16/97 | MAAC | Delmarva Power Company | VR | N/A | N/A | Weather – High demand |

# System Disturbances — 1997

| Date | Region | Utilities | Type | MW | Customers | Cause |
|---|---|---|---|---|---|---|
| 08/17/97 | ECAR | Allegheny Power System | INT | N/A | 38,500 | Weather |
| **08/26/97** | **WECC** | **230 kV Line Reactor Failure in the Western Interconnection** | **INT** | **28** | **0** | **Equipment failure** |
| **09/21/97** | **WECC** | **Islanding of Generating Station X in the Western Interconnection** | **INT** | **30** | **0** | **Transmission line fault** |
| 10/23/97 | WECC | Pacific Gas & Electric Company | INT | 110 | 126,000 | Vandalism |
| 10/26/97 | ECAR | Consumers Energy | INT | 250 | 284,000 | Weather – Heavy wet snow |
| 10/26/97 | MAPP | MidAmerican Energy Company | INT | 145 | 70,000 | Weather – Heavy wet snow |
| 12/04/97 | NPCC | Hydro-Québec | DR | 1,170 | 0 | Weather – Severe ice storm |
| 12/07/97 | NPCC | Hydro-Québec | DR | 1,816 | 400,000 | Weather – Severe ice storm |
| 12/25/97 | NPCC | Ontario Hydro | UO | 0 | 0 | Equipment failure |

*INT = Customer Interruptions, DR = Demand Reductions, VR = Voltage Reduction, PA = Public Appeal, and UO = Unusual Occurrences

# Disturbance Analysis Working Group

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