1998
System
Disturbances

Review of Selected
Electric System Disturbances in
North America

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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 1998 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 NERC at 609-452-8060.

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INTRODUCTION

NERC and the U.S. Department of Energy (DOE) have established requirements for reporting major electric utility system emergencies (Appendix A). These emergencies include electric service interruptions, unusual occurrences, demand and voltage reductions, public appeals, and acts of sabotage, that can affect the reliability of the bulk electric systems and fuel supply problems.

NERC's annual review of system disturbance reports begins in November when the Disturbance Analysis Working Group meets to review and discuss each disturbance reported to NERC and DOE so far that year. The Working Group selects reports it believes to be of value to the industry and then contacts the Regional Council or utility involved and requests a detailed report of each incident. The Working 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 in Appendix B.)

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 1998, utilities reported 63 incidents of system disturbances, demand reductions, voltage reductions, public appeals, or other occurrences. These incidents are listed chronologically in Appendix C and categorized as:

- Forty-six system interruptions
- Five unusual occurrences
- One demand reduction
- Three public appeals
- Three voltage reductions
- One voltage reduction and interruption
- Four public appeals and interruptions

This document contains analyses of four incidents plus a commentary on an incident in which a tornado struck and destroyed a control center. Unless otherwise noted, the recommendations included in each analysis are from the Region, pool, or utility and not from the Disturbance Analysis Working Group.

On pages 7 and 8 are tables of Disturbances by Analysis Category that offer quick reviews of the operating and planning categories applicable to each incident.

COMMENTARY

System Protection

The system operator is essential to the steady-state security of the transmission system, however, automatic protection schemes make the necessary millisecond decisions to isolate faulted lines or other system elements and maintain system voltage and frequency. The desired results of these schemes with their relays, breakers, underlying control schemes, and communication systems are to confine electric system problems to the affected equipment without unnecessarily interrupting customer service. The Working Group identified several factors related to system protection that contributed to the 1998 system disturbances. They were inadequate system protection maintenance programs or procedures, and miscoordination of system protection schemes for certain system conditions.

References:
- Northern MAPP/Northwestern Ontario — June 25
- Loss of Major Transmission Lines and Manual Load Shedding in Colorado — July 17

Communications

The need for timely, adequate communications among control areas during disturbances continues to arise during the analysis of disturbances. This year's review is no different. Control areas and Regional Councils have established commu-nications networks to facilitate communications, but these facilities were either not used or not used effectively. In addition, prior to system resto-ration, communications between control areas or between utilities are a necessity to establish the state of the transmission systems.

Reference:
- San Francisco Area Power Outage — December 8

Planning

System planners and operators need to work together during the design of new facilities and modification of existing facilities. More importantly, they must continually review system disturbances and their operating procedures to see if changes are needed to permit operators to more effectively handle disturbances. In one event, the damage caused by an ice storm was far in excess of the multiple contingency events system operators and planners typically model. In another event, the need to review synchronization philosophy and field circuitry to ensure they still match operational requirements was made clear. Failure of utility fiber optic circuits during an ice storm highlighted the need for redundant communications circuits for voice and data to improve coordination and restoration during disturbances. Planners also must work with newly developing organizations that are now sharing operational responsibilities, such as Independent System Operators.

References:
- Northeastern North America Ice Storm — January 5–10
- Northern MAPP/Northwestern Ontario — June 25
- San Francisco Area Power Outage — December 8

Training

Utilities should have a plan for initial and continual training of those responsible for operating and maintaining electricity systems. That plan should address required knowledge and competencies and how they can be used in real-time operations. Three of the events in this report point to the need for well-trained system operators and maintenance personnel. Failure of operators to return the system to a reliable state within prescribed time limits after a disturbance greatly compounded one outage. In another instance, operator failure to maintain reserve requirements expanded the outage. In a third instance, a major outage occurred due to inadequate maintenance personnel training and failure to follow maintenance procedures — a line was being energized, temporary protective ground straps were still in place, and system protection had not been restored after work was completed.

References:
- Northern MAPP/Northwestern Ontario — June 25
- Loss of Major Transmission Lines and Manual Load Shedding in Colorado — July 17
- San Francisco Area Power Outage — December 8

Operations

Utility day-to-day operations can significantly effect the consequences of a system disturbance. Paying attention to what may seem to be routine procedures is important, as two disturbances illustrated. Failure to maintain proper line clearances by regular tree trimming was the cause of, and contributed to the length of, one disturbance. Not maintaining substation switching logs and not having an advance comprehensive written test plan were contributing factors in another disturbance.

References:
- Loss of Major Transmission Lines and Manual Load Shedding in Colorado — July 17
- San Francisco Area Power Outage — December 8

Need for Alternative Remote Control Center

Severe storms traditionally damage the transmission and distribution systems. Other than applying protective schemes to limit the spread of outages and developing alternative paths to reroute the flows of electricity, not much can be done when Mother Nature visits. However, other vulnerable parts of the utility system should be considered and contingency plans developed. Central Louisiana Electric Company realized this when a tornado struck and destroyed the building housing its control center. Fortunately, no one was killed, but the Center was out of operation until most of the computer control systems could be relocated to another facility.

Reference:
- Central Louisiana Electric Tornado — February 26

DISTURBANCES BY ANALYSIS CATEGORY

Operating Policies

Operating Policies	Incident Number					
	1	2	3	4	5	
Policy I. Generation Control and Performance						
A. — Operating Reserve			X			
B. — Automatic Generation Control		X				
H. — Control and Monitoring Equipment				X		
Policy 2. Transmission						
A. — Transmission Operations	X	X		X		
Policy 4. System Coordination						
A. — Monitoring System Conditions						
D. — System Protection Coordination			X			
Policy 5. Emergency Operations						
A. — Coordination With Other Systems	X	X		X		
E. — System Restoration	X					
Policy 6. Operations Planning						
B. — Emergency Operations	X					
D. — System Restoration	X					
E. — Control Center Backup					X	
Policy 7. Telecommunications						
A. — Facilities	X					
C. — Loss of Telecommunications				X		
Policy 8. Operating Personnel and Training						
C. — Training				X		

1. Northeastern North America Ice Storm — January 5–10
2. Northern MAPP/Northwestern Ontario Disturbance — June 25
3. Loss of Major Transmission Lines and Manual Load Shedding in Colorado — July 17
4. San Francisco Area Power Outage — December 8
5. Central Louisiana Electric Control Center Tornado — February 26

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					
F. — Disturbance Monitoring	X					
II. System Modeling Data Requirements						
III. System Protection and Control						
A. — Transmission Protection Systems	X	X		X		
C. — Generation Control and Protection		X				
IV. System Restoration						
A. — System Blackstart Capability				X		

1. Northeastern North America Ice Storm — January 5–10
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DISTURBANCES

1. Northeastern North America Ice Storm — January 5–10, 1998

Summary

Beginning late in the evening of January 5, 1998, a series of ice storms swept across the northeastern part of North America, affecting southeastern Ontario, southwestern Québec, northeastern New York, the northern portion of New England, and the Bay of Fundy area in the Maritime Provinces. The ice storms persisted until January 10 and caused extensive damage to portions of the transmission (770 towers collapsed) and distribution systems and interrupting electric service to millions of customers. Ice accumulations of about three inches (80 millimeters) were recorded in Québec — the highest accumulations ever recorded in the Northeast Power Coordinating Council (NPCC). These storms have been characterized as "the storms of a lifetime" because of both their severity and duration. Despite the severity of the event, none of the disturbances that occurred unduly affected the security of the interconnected systems. Although specific areas of the NPCC systems were severely damaged, the bulk transmission grid remained largely intact and at no time was the integrity of the Eastern Interconnection bulk electric system seriously at risk.

Impacts by Area

Québec

The highest ice accumulations were recorded in Québec, resulting in the most severe impacts of any of the affected areas. On the transmission system, the sheer weight of ice on the conductors and towers resulted in crushing hundreds of Hydro-Québec towers carrying 735 kV, 315 kV, 230 kV, and 120 kV circuits. In total, system protection schemes removed from service thirteen 735 kV, twenty-five 315 kV, fifteen 230 kV, and seventy-three 120 kV lines. At the distribution level, the combination of ice on the conductors and attached cables, as well as the effects of falling trees and branches, collapsed thousands of poles.

The main effects of the ice storm were felt in the Montreal area and areas south and west of the city. At one point, following the loss of four out of five 735 kV lines ringing Montreal, the entire city was dependent on a single 315 kV line supplying electricity to the island on which the city is located. To the southeast, loss of the primary 230 kV sources in the Saint Cesaire area resulted in a total loss of electric service to customers in the area. At the peak of the storm, about 1.4 million customers (about half of the total number in the province and representing about 8,500 MW of demand) were without electricity.

The ac transmission lines supplying both the 1,000 MW HVDC Chateauguay tie to New York and the 225 MW Highgate HVDC tie to New England were damaged and no longer provided electricity to these facilities. One pole of the 2,000 MW Phase II HVDC tie to New England was removed from service late on January 9 but continued in mono-polar operation throughout the ice storm. With ample generation sources and the bulk of its 735 kV system still intact, Hydro-Québec maintained exports to New Brunswick throughout the ice storms via the two 350 MW HVDC ties at Madawaska and Eel River. In general, protection systems and control aids operated correctly except for minor abnormal relay operations. At no time was the security of the bulk transmission system of TransEnergie in jeopardy. The emergency response organization in place proved to be effective and efficient in dealing with an unparalleled crisis.

Ontario

The eastern portion of the Ontario Hydro system affected by the ice storm contains the major demand center of Ottawa as well as numerous smaller communities. At various times during the storm, the transmission out of service included two 500 kV, twelve 230 kV, and nine 115 kV lines as well as numerous distribution circuits. A number of these lines were out for only short periods, enabling the transmission system to continue to serve customers in this area (although the demand was greatly reduced due to distribution outages). The radial 230 kV ties to Hydro-Québec were badly damaged and outages of 230 kV lines in the area of Saunders generating station (along with problems in New York) briefly left a small amount of Ontario generation islanded with upstate New York. On January 9, system protection removed from service the second of two 500 kV lines to Ottawa for a short period, leaving the city dependent on two 230 kV lines. As in Québec, the distribution system was badly damaged in many locations resulting in an estimated 270,000 customers without electric service.

New York

About 110,000 customers were affected in northeastern New York due to the loss of 230 kV and 115 kV lines in this area. On the evening of January 8, this area operated as an electrical island following loss of the 230 kV ties to Ontario and the 115 kV ties to New England and the remainder of New York. After a half day, the island was reconnected electrically to Vermont via a single 115 kV line and it operated in this configuration for another three days until other electrical ties were restored. The main electrical ties to Hydro-Québec via the 765 kV Chateauguay-Massena and Massena-Marcy circuits were removed from service on January 8 and 9, respectively, due to ice damage. The lines remained out of service for several weeks while repairs were made.

New England

In New England, the Maine, Vermont, and New Hampshire areas were the most severely affected, with electric service to an estimated 500,000 customers interrupted, due mainly to the storm effects on the distribution systems. On the transmission side, six 115 kV lines were removed from service due to ice damage, although no customers lost service because of these events. The storm did cause the 345 kV transmission line to the Maritimes to open, but because of light flows, the underlying 115 kV system in Maine was able to maintain synchronism with the Maritimes area. About 100 MW of emergency export energy was supplied from Vermont to the isolated Saint Cesaire area of Hydro-Québec via a 120 kV line in the area of the Highgate HVDC station.

Maritimes

The Maritimes sustained only minor damage, experiencing mainly distribution outages. The Bay of Fundy area in New Brunswick was affected by the ice storm on January 8–10, and electric service to about 28,000 customer was disrupted. Two 345 kV, three 138 kV, and several 69 kV line faults occurred during this period but nothing seriously affected the bulk transmission network.

Restoration

Efforts aimed at restoring damaged transmission and distribution circuits began during the week of the ice storm and continued for weeks afterward. Hundreds of utility crews from outside the affected areas were brought in to assist with these efforts and thousands of military personnel in both Canada and the United States were used to help with removal of debris so utility crews could concentrate on electric service restoration. Equipment that had to be replaced or repaired in Québec included 16,000 wood distribution poles (another 10,750 in Ontario), 4,000 pole-top transformers (1,800 in Ontario), 3,000 transmission structures (including 1,000 steel structures), and 1,800 miles of transmission and distribution circuits were re-strung. Despite the damage suffered by the systems in NPCC as well as the obstacles to restoring service because of persistent foul weather, repair of the system proceeded steadily due to the high level of communication, coordination, and cooperation exhibited among all NPCC control areas. Electric service was restored to customers by January 15 in the Maritimes, January 27 in Ontario and New England, January 30 in New York, and February 8 in Québec. Throughout the restoration process, NPCC staff held conference calls between the NPCC control areas and neighboring Regions to ensure continuous communication and to promote the coordination of restoration efforts. These conference calls also served to keep NERC staff informed of the situation and, through the establishment of a single NPCC media contact, disseminate information to the media in a uniform, coherent, and timely manner.

TransEnergie reinstalled all overhead ground wires before summer and, prior to the 1998/99 winter peak demand period, all transmission lines were reconstructed to more stringent design criteria. Furthermore, planned reinforcement projects were achieved as scheduled so that Hydro-Québec would be better able to face a similar situation should it recur.

Conclusions and Recommendations

The damage caused to the bulk electric system by the ice storm was far in excess of multiple contingency events typically modeled by system operators and planners. Despite the resulting effects on the ability of the various utilities to serve their customers, the security of the bulk electric system was maintained. After-the-fact analysis of the state of the NPCC bulk electric system facilities at all stages of the crisis has shown that the system was operated within safe limits.

No major instances of protective relay system failures or misoperations were reported. Ice-related attenuation of power line carrier blocking signals on a section of 345 kV line in Maine resulted in two false trips as a result of faults on nearby 115 kV lines. Maine and New Brunswick also both experienced over-trip cases in which a 345 kV line tripped due to a high impedance ground fault on an adjacent line. The problem in both cases was found to be a system protection coordination problem during high impedance faults when the respective Maine Yankee and Point Lepreau units were offline. None of these events had any significant effects on the bulk electric system.

System protection, voice, and data communications were maintained throughout the period of the ice storm. The destruction of large numbers of distribution poles and their attached cables combined with wide-spread electric service outages to telephone switching centers severely disrupted communications over the public- switched telephone network, fiber optic, and cellular systems. Similarly, problems were experienced with the fiber optic systems on many of the downed transmission lines — the fiber cables often being cut along with the conductors during the cleanup process. The most reliable means of communications was found to be the utility-owned and operated microwave and mobile radio systems. Emergency generators located at many of the communication sites were pressed into action to maintain the battery systems until normal supplies from local feeders could be re-established.

All areas affected by the ice storm displayed a high degree of cooperation and coordination in dealing with events as they unfolded as well as through mutual assistance during the long restoration (construction) process.

Refer to: NERC Operating Policy 2 — Transmission
NERC Operating Policy 5 — Emergency Operations

NERC Operating Policy 6 — Operations Planning
NERC Operating Policy 7 ––Telecommunications
NERC Planning Standard I — System Adequacy & Security
A. Transmission Systems
F. Disturbance Monitoring
NERC Planning Standard III — System Protection and Control
A. Transmission Protection

For more information on this disturbance, refer to the NPCC January 1998 Ice Storm Report dated June 26, 1998.

2. Northern MAPP/Northwestern Ontario Disturbance — June 25,1998

Summary

A severe lightning storm in Minnesota initiated a series of events early in the morning of June 25, 1998, causing a system disturbance that affected the entire MAPP Region and the northwestern Ontario Hydro system of NPCC. At 0134 hours CDT, system protection opened one of the three Twin Cities 345 kV Export Ties (TCEX) (Prairie Island-Byron) due to a phase A to ground fault. An attempt was made to manually re-energize the line but, because of the large amount of electricity being transferred, the phase angle across the open breaker was 41 degrees and synchrocheck relays set at 40 degrees blocked restoration of the line. At 0201 hours, system protection opened a 161 kV line (Alma-Rock Elm) in the TCEX area, further weakening the system. At 0218 hours, 44 minutes after the first 345 kV outage, a second 345 kV TCEX line (King-Eau Claire) was struck by lightning.

The opening of the Prairie Island-Byron 345 kV line put the transmission system in an insecure state and not able to withstand the next contingency. The Twin Cities 345 kV Export Ties flow was 1,004 MW and had not been reduced by the Northern States Power Company System Operators to achieve the safe Operating Guide stability limit of 700 MW prior to the subsequent outage of the King-Eau Claire 345 kV line. Following the King-Eau Claire 345 kV outage, the remaining lower voltage transmission lines emanating from the Twin Cities area were significantly overloaded and system protection began removing them from service. This cascading removal of lines from service continued until the entire northern MAPP Region was separated from the Eastern Interconnection.

The impact of the disturbance was widespread, affecting the entire MAPP Region and the northwestern Ontario Hydro system. Northern MAPP separated electrically from the Eastern Interconnection forming three islands and resulting in the eventual blackout of the northwestern Ontario Hydro system (Figure 1). In the MAPP Region, more than 60 transmission lines and more than 4,000 MW of generation were removed from service and more than 39,000 customers (300 MW) were affected. In the northwestern Ontario Hydro system, all of the tie lines and about 270 MW of generation were removed from service and more than 113,000 customers (650 MW) were affected.

No major damage to equipment was reported as a result of the disturbance. The system operators returned the transmission and generation facilities to normal within 19 hours after the disturbance began.

The MAPP Operating Standards were violated during this incident. The system was not restored immediately to a secure operating condition prior to the next contingency. NERC Operating Policies were also violated during the disturbance.

Islands Formed

Figure 1

Impacts by Areas

NPCC

When system protection began to remove from service the ties between Minnesota and Wisconsin, part of the "surplus" electricity from the MAPP Region attempted to flow to Wisconsin the "long way around" through Ontario. Imports into western Ontario jumped to 245 MW from Manitoba and to 180 MW from Minnesota and both ties opened simultaneously. These outages forced the eastern Ontario 230 kV ties to carry the full 380 MW of export to western Ontario. The resulting power swings lowered the voltage to 17% and caused these ties to open six seconds later. The voltage in the entire western portion of Ontario collapsed as frequency fell below 55 Hz before underfrequency load shedding could activate. This area was restored by 0600 hours.

Manitoba/Saskatchewan/Minnesota/North Dakota/South Dakota "Island"

The frequency in the "island" went to about 61 Hz and stayed there for almost four minutes. At that point, an event occurred (0226 hours) in North Dakota that resulted in the separation of North Dakota and parts of Montana, Minnesota, and South Dakota into a separate smaller island. Separation of this smaller island with a generation surplus dropped the frequency in the larger island to near 60 Hz, resulting in its automatic synchronization to Eastern North America 12 seconds later when one of the open lines on the island boundary automatically reclosed. Several other lines also reclosed to tie this island securely to the Eastern Interconnection.

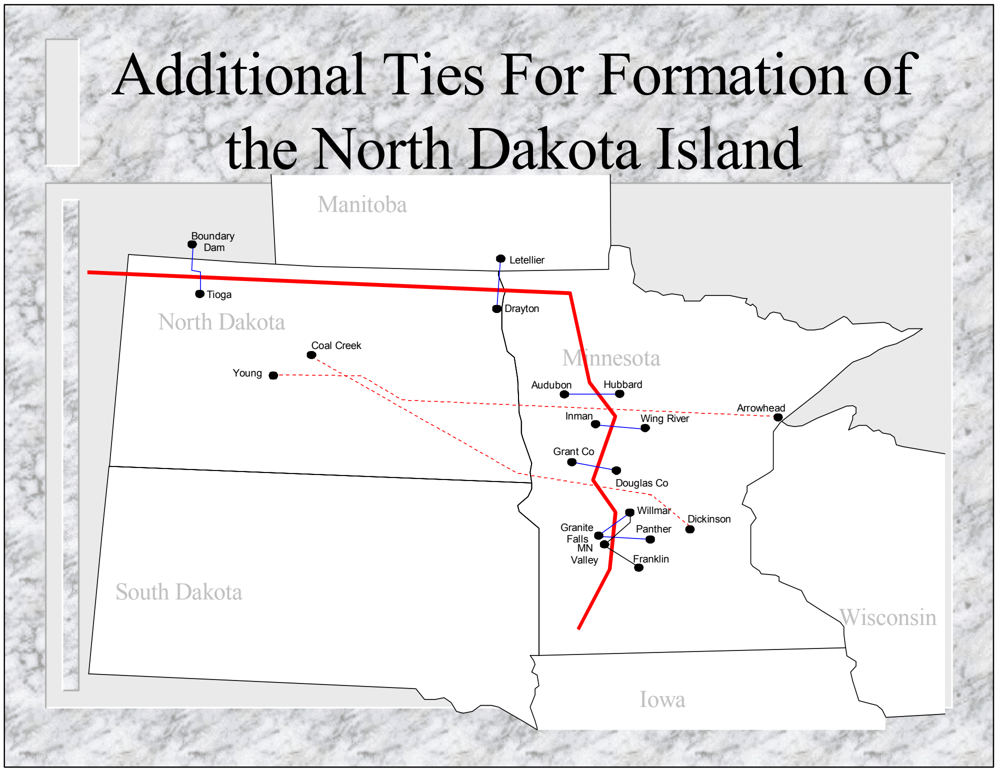


Figure 2

North Dakota/South Dakota/Montana "Smaller Island"

Prior to the disturbance, electricity from generating plants in the North Dakota coal fields was being transferred to the east on various alternating current (ac) lines and two HVDC lines, the Cooperative Power Association-Units Power Association (CU) HVDC (at 810 MW) and the "Square Butte" HVDC (at 300 MW). Generation at the CU source-end was operating at 840 MW and the differential amount of energy flowed into the associated ac lines. When the initial large island was formed, the 61 Hz frequency caused the governors on the generating units to lower their output to 540 MW (300 MW drop). However, the HVDC facility has a frequency controller that allows the HVDC facility output to be increased, thus, increasing demand and reducing the frequency when the generators are operated isolated from the ac system. In this case, the controls responded to the high frequency (even though the generators were not isolated) by increasing the HVDC facility output to 1,090 MW (280 MW gain) in an effort to reduce the frequency. The result of the two actions by the generators and HVDC controllers was 580 MW of unscheduled flow entering the HVDC terminal from the ac system. With the dc power oscillating and the controls not responding to commands, the HVDC operator removed one pole of the HVDC (0226 hours) from service to reduce the facility's flow closer to the scheduled 810 MW level. On doing this, the bus voltage rose and system protection removed the second pole from service 28 seconds later due to over voltage. Complete loss of the CU HVDC transferred the flows onto the parallel ac lines, which overloaded and were removed from service in the next five seconds to complete the isolation of the smaller island (Figure 2). Frequency rose to 62.2 Hz in this island, causing system protection to remove one pole of the Square Butte HVDC from service on over-frequency protection, but the flow on the remaining pole ramped up to maintain the power flow. One 115 kV line equipped with out-of-step blocking relays was prevented from opening, keeping the island tied to the outside and causing voltage oscillations in the island as it slipped past the Eastern Interconnection every 0.6 second. About five minutes later, this line was removed from service when a wave trap faulted due to thermal breakdown caused by the out-of-synchronism currents. Frequency ran at 61.3 Hz for 30 minutes before being reduced to allow synchronization at 0304 hours.

Northwestern Ontario Hydro System

With two of its three major thermal units out of service (one due to an unplanned tube leak repair), the northwestern Ontario Hydro system depended on transmission imports during the early morning hours of June 25. These imports were within established limits and consisted of 160 MW on the two 230 kV lines from eastern Ontario, 120 MW on one of two 230 kV Manitoba Hydro ties (the second was out due to a Manitoba Hydro phase-shifter problem), and 90 MW on the 115 kV tie to Minnesota. Local hydro units and non-utility generators supplemented supply to about 650 MW of area demand.

As transmission lines began to open between Minnesota and Wisconsin at 0218 hours, the export flow out of Minnesota and Manitoba began to divert to its alternate path through the Ontario Hydro system. This flow was initially seen as a sudden increase to 180 MW and 140 MW, respectively, on the Manitoba and Minnesota ties. This condition activated transmission security alarms at the main Ontario Hydro Control Center, resulting in a call to the Minnesota Power Coordinator requesting a flow reduction. Three minutes later, continuing line outages in MAPP resulted in a second surge into Ontario Hydro, driving the flows to 244 MW and 177 MW, respectively, on the Manitoba and Minnesota ties. These ties opened 28 seconds later due of overload and out-of-step protection operations, suddenly shifting their combined flow of 420 MW onto the remaining 230 kV ties to eastern Ontario. This sudden increase in flow was too much for these ties (385 miles to the central Ontario Hydro transmission network) resulting in their removal from service six seconds later due to power swings and voltage collapse. The Thunder Bay thermal unit in the resulting northwestern Ontario Hydro island was removed from service by underfrequency protection after four seconds and virtually the entire area blacked out within 22 seconds of the separation.

Within 40 minutes, restoration efforts were under way with the re-energization of the 230 kV transmission lines from eastern Ontario Hydro. High-voltage problems at Lakehead, near the western end of Lake Superior, halted restoration efforts from this direction at 0316 hours. However, following resolution of a supervisory control and data acquisition system problem at Kenora in the west, restoration from Manitoba Hydro began at 0331 hours. By 0351 hours, the two parts of the system were connected at Lakehead and restoration of outlying areas continued. The tie to Minnesota was re-established at 0457 hours and service was restored to all customers by 0600 hours, about three and half hours after the outage began.

Other Points Noted in the MAPP Disturbance Report

- Standards of Conduct required by FERC Order Nos. 888/889 were suspended by several utilities and the MAPP Security Center due to the emergency conditions.
- NERC Operating Policy 2 was violated by not getting under the TCEX limit within 30 minutes. The MAPP policy, calling for action within ten minutes, also was violated.
- There are no automatic generator removal from service actions for loss of any of the TCEX lines.
- An investigation was made to determine if the allowable closing angle could be increased on the

Prairie Island-Byron line, but an increase in closing angle was not possible due to concerns about the effects on the generating units in the area.
- The line loading reduction policy is not meant for emergency situations because of the time it takes to implement reductions. It is intended to be used to help prevent the system from being operated in a non-secure state.
- Attempts to reduce the line closing angle by reducing generation at the Prairie Island plant were counter-balanced by automatic generation control response at other units in the control area.
- Most of the generation removed from service was removed by overfrequency protection or governor action (resulting in boiler upsets or generators operating as motors).
- When lines to the south into Nebraska and Iowa were removed from service due to out-of-step conditions, three 345 kV lines opened, removing from service the 1,000 MW Neal generator due to over-excitation during the collapsing voltage.
- Generator governor operations in North Dakota were reviewed and some units required corrections.
- The sustained operation of thermal units at 61.3 Hz for 30 minutes is being evaluated regarding turbine blade fatigue damage.
- Automatic reclosing greatly assisted in restoration of the large island.
- System control and data acquisition (SCADA) synchrocheck angles were helpful in re-synchronizing the smaller island.
- Some SCADA systems lost data due to the large number of alarms.
- Many frequency meters/charts went off scale and did not record the maximum frequency deviations.
- Lack of time synchronization made reconstruction of the events difficult. However, the Minnesota dynamic system monitors, which have accurate frequency transducers and global position satellite time synchronization, were invaluable.
- Manitoba Hydro dc reductions and other protective actions on the Manitoba Hydro bipoles reduced the bipole flows by about 1,200 MW. This reduction was beneficial in keeping the frequency rise to a minimum and preserving the ties south into Minnesota.
- When Saskatchewan separated from North Dakota, its 230 kV Boundary Dam voltage increased to 274 kV (1.19 pu).
- The Watertown Static VAR System in the small island helped to damp the voltage oscillations.
- Most of the demand lost was due to under voltage load shedding.

Conclusions and Recommendations

The MAPP Operating Standards were violated during this incident. The system was not readjusted immediately to a secure operating condition prior to the next contingency. NERC Operating Policies were also violated during the disturbance.

The primary recommendations of the final MAPP Disturbance Report, which have all been implemented, were:

1. The system must be operated within approved Operating Guide limits.

2. Following a contingency, the system must be returned to a reliable state within the readjustment period allowed in the MAPP standards. Operating Guides must be reviewed to ensure procedures exist to restore system reliability in the allowable time periods.

3. Operating Guides should not rely on MAPP Line Loading Relief (LLR) procedure in its current state, when the system is in an insecure state. Other readjustments must be used, and the local operator must take responsibility to restore the system immediately.

4. Phase-angle restrictions that can prevent reclosing of major interconnections during system emergencies should be reviewed and approved by the MAPP Operating Review Subcommittee. MAPP should seriously consider bypassing synchrocheck relays to permit direct closing of critical interconnections when it is necessary to maintain stability of the grid during an emergency.

The report also made 60 detailed recommendations to avoid a similar situation in the future. The report recommended that systems should review the NERC Operating Policies violated during the disturbance and take corrective action, specifically with regard to Operating Policies 1, 2, and 5.

Although the extreme contingency disturbance began outside of Ontario Hydro and the loss of the western area demand was inevitable under the circumstances, subsequent investigation of the event by Ontario Hydro resulted in 18 recommendations to mitigate the effects of similar future disturbances.

Refer to: NERC Operating Policy 1 — Generation Control and Performance
- A. Automatic Generation Control

NERC Operating Policy 2 — Transmission
- A. Transmission Operations

NERC Operating Policy 5 — Emergency Operations
- A. Coordination with Other Systems

NERC Planning Standard III — System Protection and Control
- A. Transmission Protection Systems
- B. Generation Control and Protection

For more information, refer to the Northern MAPP/Northwestern Ontario Disturbance, June 25,1998 Final Report. All of the report recommendations have been addressed.

3. Loss of Transmission Lines and Manual Load Shedding in Colorado — July 17, 1998

Summary

Public Service Company of Colorado (PSCo) experienced high transmission system loadings due to a combination of hot weather and 480 MW of generating unit forced outages on July 17, 1998. At 1333 MDT, system protection removed the Hayden-Gore Pass-Blue River-Dillon 230 kV line from service, due to tree contact. It was closed at 1342, but was again removed from service at 1344. The change in line flows caused the Rifle-Hopkins-Malta 230 kV line to be removed from service at 1345, along with several other low-voltage lines. The loss of these lines shifted flows such that transmission from Wyoming into Colorado became overloaded. Voltages along the Colorado Front Range became depressed and PSCo shed about 200 MW of demand at 1350 and an additional 100 MW at 1352 to prevent further voltage decline. As a result, frequency increased to 60.03 Hz. With the restoration of the Rifle-Hopkins line, all demand was restored at 1417. The Rifle-Hopkins line was again removed from service, requiring demand to again be shed in 100 MW blocks, at 1430, 1439, and 1440 MDT. The sequence of demand restoration, removal of the line from service, and load shedding occurred several times before the system stabilized. It is believed that the increased line loadings due to the hot weather and redistribution of flows caused the lines to sag into underlying vegetation.

Detailed Description of the Disturbance

In Colorado, there are four defined transfer paths referred to as TOTs (Figure 1), short for total, over which power moves into or out of the state. Of the four TOTs, two of them, TOT 3 and TOT 5 are the highest rated and move the majority of the power required to the primary demand center, referred to as the Front Range. This geographical area runs from Ft. Collins in the north to Pueblo in the south, and includes the Denver metropolitan area.

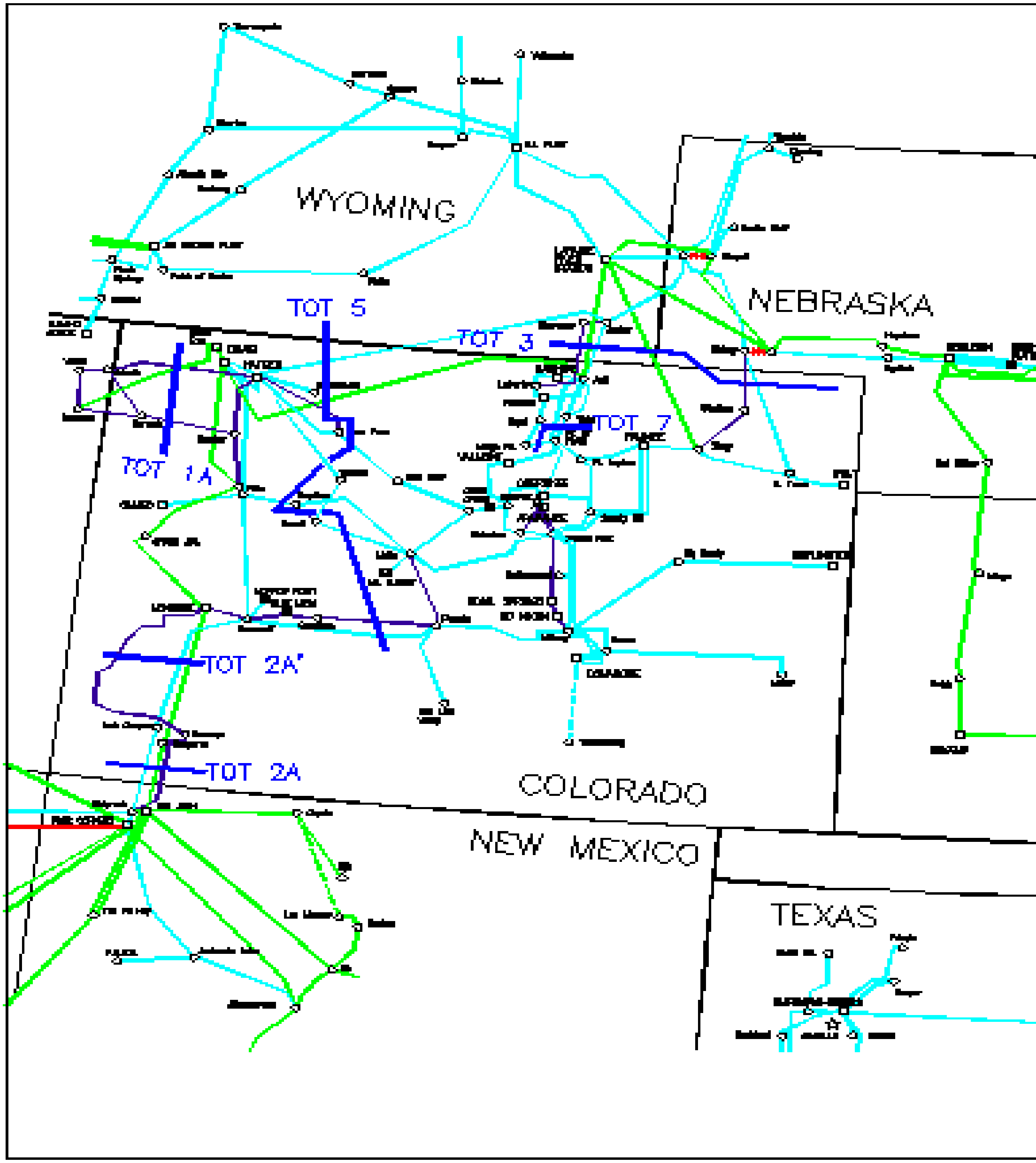

WYOMING
NEBRASKA
COLORADO
NEW MEXICO
TEXAS
TOT 5
TOT 3
TOT 7
TOT 1A
TOT 2A'
TOT 2A

Figure 1

During the week of July 12, the weather conditions in Colorado turned hot and dry with a significant increase in system demand for all utilities. On the morning of July 17, PSCo projected demand to reach 4,625 MW, equal to the 1997 summer peak. It also experienced the loss of two generation resources, Comanche Unit 1 and Cabin Creek Pump Storage Unit B, for a total of 480 MW. Also unavailable was Colorado Springs Utilities' Nixon Unit 1 (208 MW). Prior to the following events, TOT 5 had a scheduled flow of 1,573 MW, an actual flow of 1,357 MW, and the limit was 1,680 MW.

At 1333 MDT, system protection removed from service the Hayden-Gore Pass 230 kV line, operated and maintained by the Western Area Power Administration Rocky Mountain Region (WAPA-RMR), because a phase conductor touched a tree and the line faulted to ground. This system protection operation was followed by the misoperation of the Blue River-Dillon 230 kV line at Blue River.

The initial actions taken by PSCo, WAPA-RMR, and Tri-State G&T (TSGT) were to attempt to reclose the Hayden-Gore Pass and Blue River-Dillon 230 kV lines. PSCo brought on line its Cabin Creek Pump Storage Unit A (160 MW) unit. The Hayden-Gore Pass 230 kV line was restored at 1342, but was again removed from service at 1344 MDT. At 1346 MDT, PSCo's Rifle-Malta 230 kV line was again removed from service when a conductor touched a tree.

Within two minutes, system protection opened the Blue Mesa terminal of the Blue Mesa-Skito 115 kV line and the Poncha-San Luis 230 kV line and associated 230/115 kV transformer due to overload conditions. These facilities are located in southwest and south central Colorado.

PSCo dispatchers ordered all eastern Colorado generating units to switch to manual control and go to full output. At 1349 MDT, PSCo started manual load shedding of firm demand — about 223 MW. At 1356 MDT, WAPA-RMR, PSCo, and TSGT dispatchers began efforts to restore all lines that were removed from service. The Hayden-Gore Pass 230 kV and Hayden-Gore Pass 138 kV lines were successfully energized. Between 1410 and 1413, TSGT dispatchers manually shed 55 MW of firm customer demands in the San Luis Valley to prevent a total voltage collapse in the area, when the 115 kV system voltage dropped to 95 kV. At 1414 MDT, the Rifle-Malta 230 kV line was energized and the 223 MW of firm demand was restored.

The 230 kV breakers at PSCo's Blue River Substation would not close due to the significant voltage difference across the open breakers. The Blue Mesa 115 kV line also remained open due to a significant phase angle across the open breaker. This situation resulted in two elements of TOT 5 being out of service.

At 1425 MDT, the Hayden-Gore Pass 230 kV line faulted again due to conductor contact with a tree, and 12 minutes later the Rifle-Malta 230 kV line faulted again. PSCo immediately shed 207 MW of firm demand. Between 1454 and 1556, PSCo's test energized the Rifle-Malta 230 kV line, which resulted in the line being removed from service three times.

WAPA-RMR dispatched crews to the suspected fault location on the Hayden-Gore Pass 230 kV line to assist fire fighting crews battling a forest fire in the line right-of-way.

The Hayden-Gore Pass, Rifle-Malta, and Gore Pass-Blue River 230 kV lines were all returned to service by 2025 MDT. The Blue Mesa-Skito 115 kV line was restored at 2205.

Conclusions and Recommendations

The following is a summary of the conclusions and recommendations that resulted from this event:

- There were nine violations of reserve requirements
- Tree trimming practices by PSCo and WAPA were contributing factors
- Relay misoperation and failure to identify and correct the problem on July 17 was a contributing factor

Refer to: NERC Operating Policy 1 — Generation Control and Performance
A. Operating Reserve — Criteria
NERC Operating Policy 4 — System Coordination
D. System Protection Coordination
Requirement 2 — Notification of Failure and corrective action
Guide 2 — Protection system implementation, operation, and maintenance
Guide 2.4 — Testing and maintenance
Guide 3 — Reviewing abnormal operation

For more information on this disturbance, please contact the Western Systems Coordinating Council technical staff.

4. San Francisco Area Power Outage — December 8, 1998

Summary

At about 8:15:24 PST on the morning of December 8, 1998, Pacific Gas & Electric Company (PG&E) experienced a severe disturbance that resulted in the blackout of most of the City of San Francisco and nearby communities on the San Francisco Peninsula. The blackout affected more than 456,000 customers (nearly one million people) and interrupted about 1,200 MW of demand. PG&E's Hunters Point and Potrero power plants and the United Cogenerator at the San Francisco International Airport were also affected by the disturbance.

The disturbance was caused by failure to follow procedures by a PG&E construction crew and by the substation operator at the San Mateo substation. The PG&E construction crew failed to completely remove all the temporary protective ground straps from the San Mateo 115 kV bus following completion of reconductoring and switch replacement work. The crew foreman on that job, without verifying that all the safety grounds had been removed and accounted for, reported to the San Mateo switching center that the equipment was ready to be energized.

A three-phase fault occurred when the grounded bus was energized. The local system protection scheme did not clear this fault because the San Mateo substation operator had failed to engage bus differential protective relaying prior to energizing the bus. If either the construction crew had properly removed the grounds or the substation operator had properly placed the relaying in service, the disturbance would have been either limited to a localized system protection operation or would have not occurred at all.

During the fault and immediately after it was removed, radical power swings occurred on the transmission system supplying San Francisco. Within about 16 seconds, all of the generation in the San Francisco island was tripped by underfrequency protection and the blackout of the city was complete.

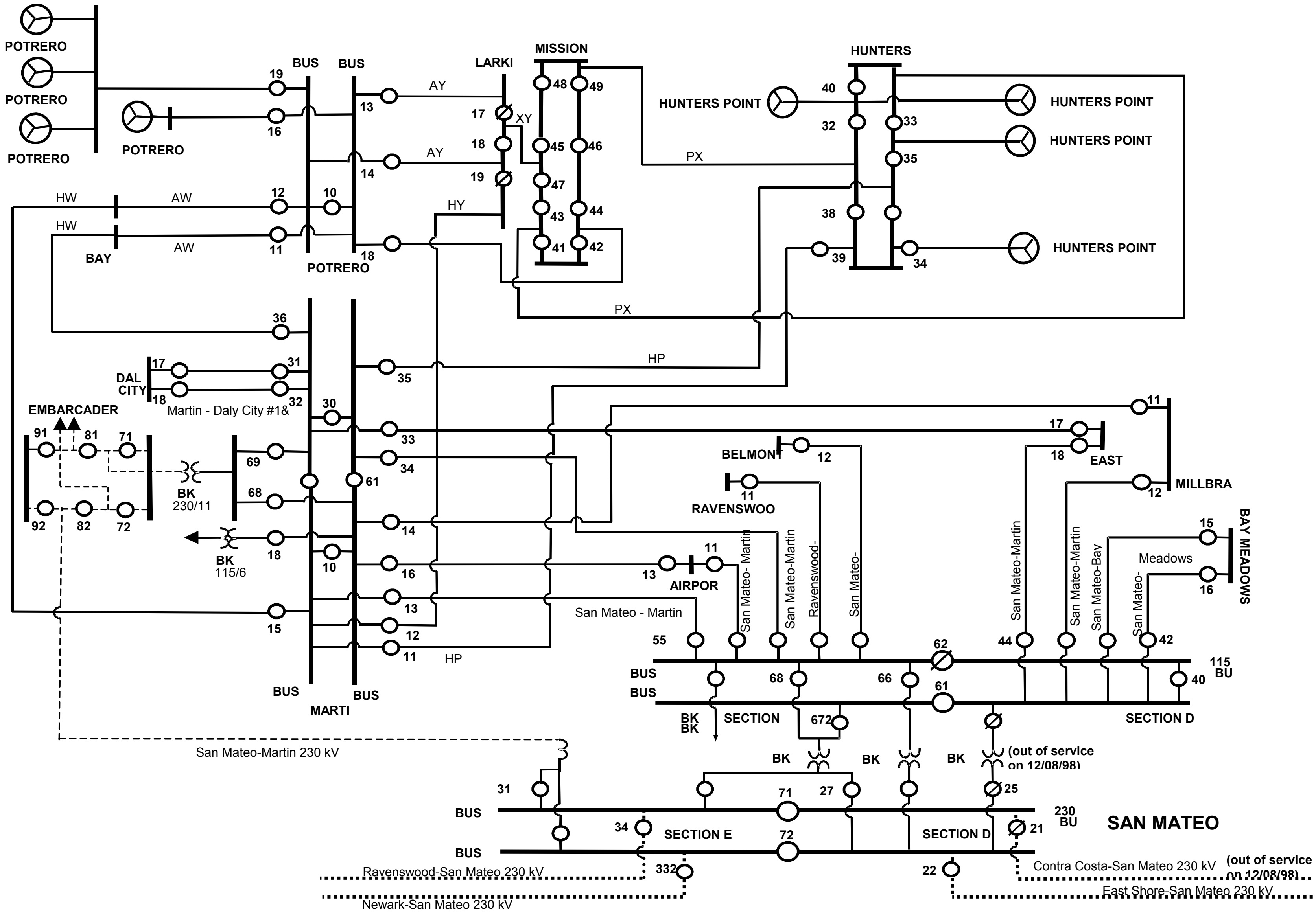
Description of the San Francisco Electrical Network

The San Francisco electrical demand area consists of the City of San Francisco and the northern portion of San Mateo County. San Francisco area demand varies based on the seasons and temperature. Its peak demand typically varies between 750 and 900 MW. Historically, the period following Thanksgiving weekend and just before Christmas is a very high demand period. This increase is primarily due to the increase in decorative Christmas lighting and extended store hours.

San Francisco and northern peninsula demands are primarily supplied from a single transmission corridor along the peninsula past the San Francisco airport and from local generation located in San Francisco. San Mateo substation is the primary source for energy flowing towards San Francisco and the peninsula. San Mateo substation is located near the San Francisco Bay, and has transmission lines entering and exiting at 60 kV, 115 kV, and 230 kV voltage levels.

The single-line diagram of the transmission system serving the San Francisco area is shown in Figure 1.

FIGURE 1 SINGLE-LINE AND BREAKER LAYOUT FOR SAN FRANCISCO AREA



The San Francisco operating instructions dictate the amount of in-area generation that is required in the San Francisco area at all times. This requirement is to ensure reliability and to minimize the risk of equipment overloads, cascading outages, and voltage collapse following a *critical single contingency* (*and certain credible double contingencies*) of a transmission/generation facility. Under normal operating conditions, the in-area energy and capacity required to maintain reliable operations in accordance with the San Francisco Operating Instructions is supplied by local generation in the Bay area.

Outage Description

At about 8:15:24 PST on the morning of December 8, 1998, a severe disturbance occurred in the PG&E service area that resulted in the blackout of most of the City of San Francisco and nearby communities on the San Francisco Peninsula. The blackout affected more than 456,000 customers (nearly one million people) and interrupted about 1,200 MW of demand.

The PG&E construction crew working at the San Mateo substation failed to completely remove all the temporary protective ground straps from the San Mateo 115 kV bus #2 section D following completion of reconductoring and switch replacement work as part of a transformer replacement project. These protective grounds are devices used by the crews to ensure their personal protection from stray electric currents induced by nearby energized equipment and as extra backup in case the lines and equipment they are working on are inadvertently energized. PG&E's grounding procedures are formal documents that specify procedures and processes that its crews should follow while installing and removing protective grounds on equipment. According to PG&E's current grounding procedure, it is the responsibility of the clearance holder to verify that all the protective grounds have been removed from power lines and equipment. The clearance holder is also responsible for ensuring that all the personnel have moved a safe distance away from the equipment prior to declaring any de-energized equipment ready for energization. The crew foreman on that job, without verifying that all the safety grounds had been removed and accounted for, reported to the San Mateo switching center that the equipment was ready to be energized.

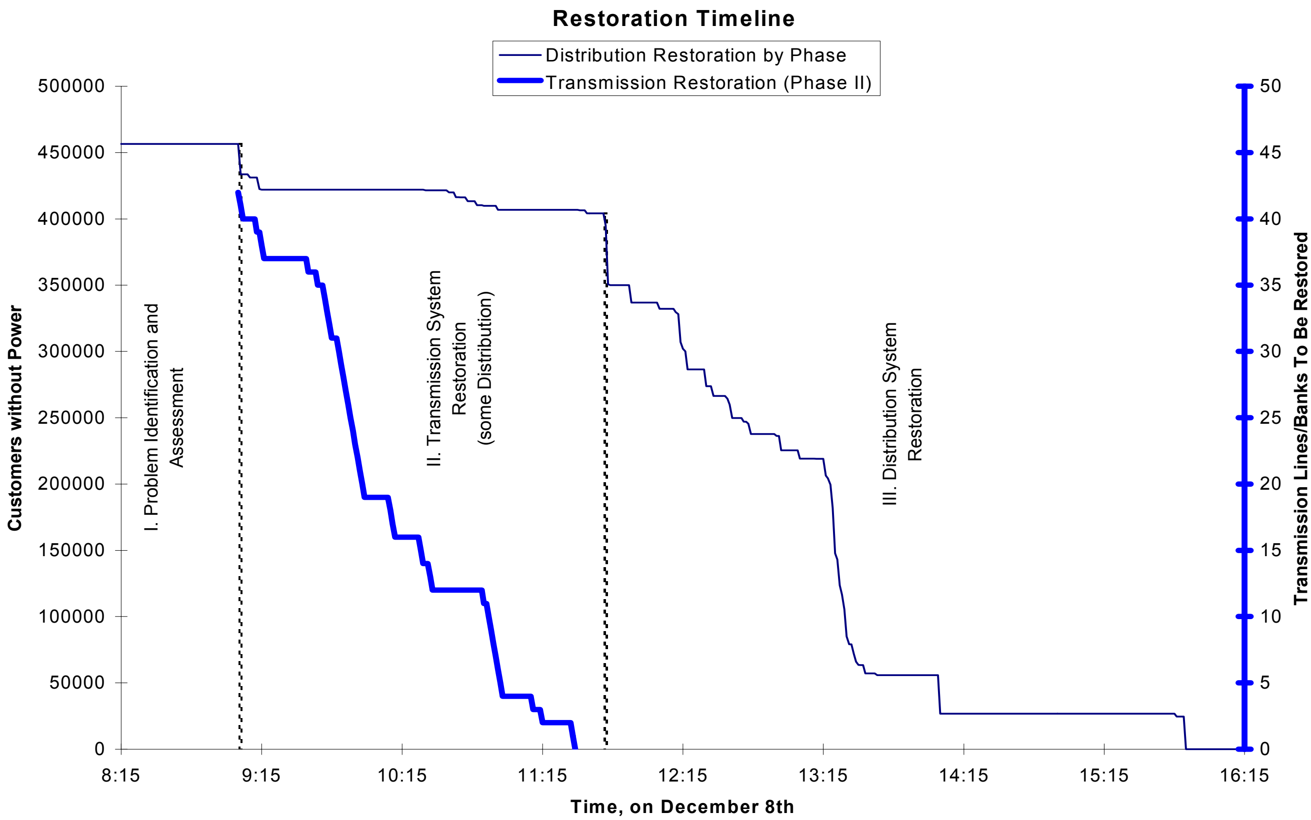
When circuit breaker 402 was closed to energize bus #2 section D, which was still grounded via the safety grounds that had not been removed, a three-phase fault occurred on bus #2 section D. The local protection scheme did not clear this fault because the San Mateo substation operator failed to engage the San Mateo bus #2 section D differential protective relaying prior to energizing the bus. The differential relays are installed to detect and isolate bus faults on bus #2 section D at the San Mateo substation. If either the construction crew had properly removed the grounds or the substation operator had properly placed the relaying in service, the disturbance would have been either limited to a localized system protection operation or would not have occurred at all.

Without any high-speed local protection in place to remove the fault from the system, delayed remote protection began to sense the fault and a number of 115 kV lines tripped in an attempt to isolate the fault. Ultimately, the fault was removed after the safety ground strap burned away. The bus protection on bus #1 section D was properly in service and opened all of the breakers connected to the bus, effectively de-energizing the faulted bus section from the system more than one-half second after the fault inception.

During the fault, and immediately after it was removed, radical power swings occurred on the transmission system supplying San Francisco. This instability caused the two largest generators in the city, Potrero #3 and Hunters Point #4, to begin their automated sequence for removal from service. Because the 115 kV transmission supply to the San Francisco area had been interrupted when the fault was cleared leaving only the 230 kV underground cable supplying the demand, the loss of the large generators caused the 230/115 kV transformer at Martin Substation to become severely overloaded. About nine seconds after the fault occurred, system protection removed the Martin 230/115 kV transformer from service due to overload creating an island of demand and a small amount of generation. Although the underfrequency load shedding system in San Francisco was initiated, it was insufficient to remove enough demand to balance with the small amount of remaining generation. Within about 16 seconds, all of the generation in the San Francisco island was removed from service by underfrequency protection and the blackout of the city was complete.

As shown in Figure 2, the transmission system was fully restored at 11:30 a.m. and all customers were restored by 4 p.m. on December 8.

FIGURE 2



PG&E encountered some problems in the service restoration phase of this outage that led to delays in service restoration. A list of these problems is given below:

- The communication modems for the SCADA RTUs at Mission, Larkin, and Potrero substations are supplied via ac power and are not connected to any source of backup power. During the outage, the communication modems were de-energized, preventing the PG&E operators from restoring service remotely and operating equipment at these substations.

- Three transmission circuit breakers (circuit breaker 192 at Potrero substation, circuit breaker 42 at Martin substation, and circuit breaker 462 at Mission substation) and 11 distribution breakers failed to function as designed during the restoration phase. The problem with breaker 192 at the Potrero substation is worth special mention. The combustion turbines at the Potrero power plant, which provide the black-start power to the thermal unit at Potrero, are connected to the electric transmission grid via CB 192. The delays that occurred while performing the closing operation directly impacted the time it took to get startup power to the 207 MVA thermal unit at the Potrero power plant.

The December 8, 1998 outage was the first major system event since the California Independent System Operator (CAISO) assumed operational control of the California power grid on March 31, 1998. During the restoration phase, from the CAISO point of view, the communication between PG&E and the CAISO was infrequent. The shift supervisor at PG&E did not provide the CAISO shift manager with a complete picture of his service restoration plan. Also, the service restoration timing information that the CAISO received from PG&E was inadequate. In anticipation of the demand coming online, the CAISO was procuring resources to maintain system frequency. However, when this demand was not restored as indicated, the CAISO was faced with over-generation conditions.

Conclusions and Recommendations

A total of 12 conclusions and 29 recommendations were developed following the incident, covering actions during both the initiation of the outage and the subsequent restoration.

Conclusion #1
The PG&E system, including San Francisco and the peninsula area, was operating within established WSCC Minimum Operating Reliability Criteria at the time of the event.

Conclusion #2
The construction crews failed to remove all grounds before re-energizing San Mateo bus #2 section D.

Recommendations
- PG&E should review its grounding policies and practices for accuracy and adequacy in accordance with the established safety standards.
- PG&E should establish/review procedures and guidelines for training personnel in ground placement and removal policies.
- PG&E should establish/review training programs for personnel to periodically reaffirm the need to follow established grounding practices and policies.
- Under PG&E's current grounding procedure, the use of grounding tailboard and checklist is optional. The use of grounding tailboard and checklist should be made mandatory in the grounding installation and removal standards.
- The CAISO will review the current ground installation and removal practices throughout its control area, and in collaboration with the participating transmission owners (PTOs), explore the possibility of implementing a standard policy for tagging all grounds.

Conclusion #3
The bus differential relay on Breaker 402 at San Mateo 115 bus #2 section D was not verified in service prior to re-energizing bus #2 section D. Initially, the relay was disabled as a part of the San Mateo 115 kV bus replacement project. Not returning the differential relays to service translated into inadequate protection at the San Mateo 115 kV bus, which, in turn, resulted in the wide-spread outage in the San Francisco area.

Recommendations
- PG&E should review its switching policies and practices for accuracy and adequacy in accordance with the established safety standards.
- PG&E should review procedures and guidelines for training personnel for re-energization of critical equipment.
- PG&E should review training programs for personnel to periodically reaffirm the need to follow established standards for re-energizing critical equipment.

Conclusion #4
The switch log prepared by San Mateo switching center operator (and located at San Mateo switching center) did not include all the standard steps associated with ensuring that the necessary protection schemes at the San Mateo 115 kV bus #2 section D were enabled prior to energizing that bus.

Recommendations
- PG&E should develop/review practices and policies regarding preparation of switching logs.
- PG&E should develop a standardized policy for preparing a switching log. Train switching center personnel in following these standardized policies.
- PG&E must implement the standardized switching log preparation policy.
- PG&E should develop a policy to prepare and submit a comprehensive written test plan to the CAISO for critical or complicated work at least four weeks prior to the start of work. This procedure is in accordance with CAISO Outage Coordination Protocol and Scheduled and Forced Outage Procedure T-113. The CAISO will provide PG&E and other PTOs a sample test plan to convey the minimum acceptable level of detail that should be included in the test plans.

Conclusion #5
PG&E's transmission operating center failed to notify the CAISO prior to starting switching operation on the San Mateo 115 kV bus #2 section D.

Recommendations
- The CAISO will coordinate a joint effort with all PTOs to develop/review a list of critical transmission facilities in the CAISO control area.
- The PTOs should inform the CAISO prior to starting and upon completion of all switching operations on the critical transmission facilities identified on the above list.

Conclusion #6
The protection schemes on the transmission system serving the San Francisco area responded as designed for the given fault condition. The exception was circuit breaker 112 at Airport Substation that operated faster than expected.

Recommendation
- PG&E must test and verify the settings on the protective relays associated with circuit breaker 112 at Airport Substation for accuracy.

Conclusion #7
More frequent communication between PG&E and the CAISO would have been beneficial in coordinating and managing the transmission network restoration following the disturbance.

Recommendation

- The CAISO and PTOs should develop/review and coordinate the implementation of appropriate emergency response procedures that include the following steps:
  - Set up of an emergency response plan.
  - Establish initial communication links with appropriate parties.
  - Assess the situation/condition.
  - Develop an appropriate approach to restore demand and resources.
  - Communicate resource and service restoration plan to CAISO and all other parties.
  - Execute the plan while maintaining communication throughout the process.

The procedure will also address the responsibility of each entity during the disturbance. The PTOs will be responsible for training the transmission operators in their respective organizations to execute the designed emergency procedure. Simulated emergency training exercises will be conducted between the CAISO and PTOs on a periodic basis to test the emergency readiness of all entities.

Conclusion #8

Inadequate communication occurred between PG&E and the CAISO shift-operation personal during service restoration, which resulted in over-generation conditions.

Recommendations

- A work group composed of representatives from the PTOs and the CAISO will be established to evaluate the adequacy and reliability of the existing communication systems, procedures, and protocols at all levels between PTOs and the CAISO under emergency conditions.
- Prior to demand restoration, the PTOs should seek the approval of and coordinate efforts with the CAISO dispatch staff to verify adequate generation resource availability.
- PTOs should promptly communicate their service restoration plans to the CAISO and provide the CAISO a good estimate of the time at which demand blocks are expected to be restored. If any obstacles are uncovered in the course of implementing that plan and any delays are anticipated, that information must also be communicated to the CAISO as soon as possible.

Conclusion #9

The modems to the SCADA system at Mission, Larkin, and Potrero substations in the San Francisco area failed due to loss of electricity. This failure prevented PG&E operators from restoring transmission lines and customers demands from a remote location, and delayed the transmission restoration process.

Recommendations

- PG&E should establish/review the design standards for its SCADA/telecommunication systems and the backup electricity source to these systems.
- PG&E should ensure that all of its existing SCADA/telecommunication systems satisfy the new/existing standards.

Conclusion #10

Circuit breaker 192 at Potrero, circuit breaker 42 at Martin, and circuit breaker 462 at Mission substations failed to operate during restoration. In addition, 11 distribution breakers also failed to close as desired during the restoration phase of the power outage.

Recommendations

- PG&E should provide the CAISO with the maintenance records for circuit breaker 192 at Potrero substation, circuit breaker 42 at Martin substation, and circuit breaker 462 at Mission substation. PG&E and the CAISO shall verify whether the maintenance on these breakers was performed in conformance with PG&E's standard breaker maintenance policies and practices.
- PG&E should review the appropriateness of its breaker maintenance practices and policies.

Conclusion #11

During the outage, ac electricity to Potrero Unit #3 was lost. This loss rendered the drive-turning gear at the plant useless following the unit's removal from service. To prevent the shaft from bending, the plant crew started to turn the shaft using the manual crank wheel. When this action failed to produce any significant results, an air drive was installed to turn the shaft. However, the problems with circuit breaker 192 at Potrero delayed the restoration of ac power to Potrero Unit #3 by preventing the Potrero combustion turbines from supplying ac start-up power to the thermal unit.

Recommendations

- The generator owners of all thermal units located within the CAISO control area should review those sections of their respective power plant's emergency operations procedures that address the actions of the plant personnel following the loss of electricity to the plants and identify any potential areas of improvement.
- Should the above recommendation result in changes to the plant emergency operations procedure, the generator owners of all thermal units located within the CAISO control area should re-train their plant personnel to follow the new procedures.
- The generator owner should review policies and conduct periodic inspections to ensure that all emergency equipment is accessible and in good operating condition at the plant.
- The CAISO and the generator owners of all the thermal plants with its control area should form a work group to establish a communication protocol between the plant operators and the CAISO dispatch staff in case of emergencies.

Conclusion #12

The combustion turbines at Potrero (Potrero #5) and Hunters Point (Hunters Point #1) were removed from service twice by system protection during the peak hour on the day of the disturbance. The relay targets on these units indicated that the cause of this outage was low voltage. The loss of critical in-area generation forced the need to shed 16 MW of customer demand during the peak hour.

Recommendations

- The owners of generation located within the San Francisco area should verify the protection settings on all undervoltage and underfrequency relays at combustion turbines and steam generators in the San Francisco area for accuracy, and make modifications, if required.
- The owners of the generation located within the San Francisco area must review the feasibility of lowering the under voltage relay settings on the San Francisco combustion turbines and make appropriate changes.

Refer to: NERC Operating Policy 1 — Generation Control and Performance
H. Control and Monitoring Equipment
NERC Operating Policy 2 — Transmission
A. Transmission Operations
NERC Operating Policy 5 — Emergency Operations
A. Coordination with Other Systems

NERC Operating Policy 7 — Telecommunications
  C. Loss of Telecommunications
NERC Operating Policy 8 — Operating Personnel and Training
  C. Training
NERC Planning Standard III — System Protection and Control
  A. Transmission Protection Systems
NERC Planning Standard IV — System Restoration
  A. System Blackstart Capability

For more information on this disturbance, please contact the Western System Coordinating Council technical staff or the California Independent System Operator.

5. Central Louisiana Electric Control Center Tornado — February 26, 1998

Summary

On February 26, 1998 at about 0900 CST, a tornado struck and destroyed the building that housed the Central Louisiana Electric Company (CLECO) Control Center. No one was killed in the incident. Most of the computer control systems were relocated to another part of the facilities after the tornado struck and were operational within a few days.

Description of the incident

At about 0900 CST on Thursday, February 26, 1998, a tornado struck the CLECO Control Center and the adjacent Coughlin power plant. The tornado collapsed the roof of the dispatch center and knocked down a 300 ft. microwave tower. In 45 seconds, all control and monitoring functions ceased. At the adjacent Coughlin plant, one gantry crane was toppled onto turbine No. 5, and another crane was blown to the ground. Miraculously, no one was killed or hurt.

CLECO did not have a backup dispatch center and had to piece one together in an undamaged part of the building. The fallen dispatch center ceiling had crushed the workstation monitors, strip-chart recorders, and the alarm printers. The workstation computers were protected by their desks and survived, as did five application node processors in the computer room and the electronic map board. The modem rack was undamaged, but the downed microwave tower had disabled all remote terminal unit (RTU) communications. CLECO no longer had any energy control capability. It was impossible to tell what lines were down or where electricity was flowing. All remote control over circuit breakers also ceased. Operators were dispatched to substations to monitor conditions and to manually operate switches. Surrounding utilities — Entergy and Central & South West — and the Southwest Power Pool, were called and notified of the situation.

Fortunately, the damaged dispatch system, which was only a year old, was constructed of modules and, therefore, easier to reconfigure. Vendor engineers who installed the system were contacted and arrived at the site on the evening of February 26. Work began on clearing a room for a new energy control center and the surviving equipment was relocated. The Information Technologies Department worked on the LAN and the Communications Department worked on restoring RTU communications and telephone lines. By the evening of February 27, the dispatch system had been reassembled and booted successfully. However, only ten of the 21 RTU communications channels were on line. Over the weekend, the telephone company installed two T1 lines into the dispatch center. By Sunday evening, February 29, all ties and major substations were on line.

Comments

Severe storms traditionally damage the transmission and distribution systems, which are outdoors and exposed. Other than applying protective schemes to limit the spread of outages and developing alternative paths to reroute energy, not much can be done when "Mother Nature" visits. There are, however, other vulnerable parts of the electricity supply and delivery system that should be considered and for which contingency plans should be made.

Refer to: NERC Operating Policy 6 — Operations Planning
E. Control Center Backup

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 5F — 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 judgement 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 EC and OC of the status of the recommendation(s) and the steps the Regional Council has taken to accelerate implementation.

NERC Disturbance Reporting Requirements

Policy 5F, Appendix 5F — Reporting Requirements for Major Electric System Emergencies

These disturbance reporting requirements apply to all entities using the electric transmission systems in North America and provide a common basis for all NERC disturbance reporting. The utility or other electricity supply entity on whose system a disturbance that must be reported occurs shall notify NERC and its Regional Council of the disturbance using the NERC Preliminary Disturbance Report form. If a disturbance is to be reported to DOE also, the responding entity may use the DOE reporting form when reporting to NERC. The report is to be made as specified in Policy 5F for any of the following events:

1. The loss of a bulk power transmission component that significantly affects the integrity of the interconnection system operation.

2. The occurrence of an interconnected system separation or system islanding or both.

3. Loss of generation by a utility or generation supply entity — 2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection or Québec Interconnection. Reports can be sent to NERC via e-mail (info@nerc.com) or by facsimile (609-452-9550) using the NERC Preliminary Disturbance Report form.

4. Equipment failures/system operational actions, which result in the loss of firm system demands for more than 15 minutes, as described below.

   4.1. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.

   4.2. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.

5. Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system.

6. Any system operation or operator action resulting in:

   6.1. sustained voltage excursions equal to or greater than ±10%, or

   6.2. major damage to power system components, or

   6.3. an event other than those covered above that a system operator in another electric transmission system might encounter and should be aware of, or

   6.4. failure, degradation, or a “near miss” of system protection, special protection schemes, remedial action schemes, or other operating systems that do not require system operator intervention.

7. An operating security limit violation as required in Policy 2A — Transmission Operations, Standard 2.2.

8. An actual or suspected act of physical or electronic (cyber) sabotage or terrorism directed at the bulk electric system or its components with intent to deny service or disrupt or degrade the reliability of the bulk electric system.

☐ **Check here if this is an operating security limit violation report**

NERC
Princeton Forrestal Village
116-390 Village Boulevard
Princeton, NJ 08540-5731
E-mail: info@nerc.com
Fax: 609-452-9550
Tel: 609-452-8060

NERC Preliminary Disturbance Report

1. Organization filing report: ______________________________

2. Name of person filing report: ______________________________

3. Telephone number: ( ) -

4. Date and time of disturbance: / / Date (mm/dd/yy) / /Time/Zone

5. Did disturbance originate in your system?

6. Describe disturbance including: cause, equipment damage, critical services interrupted, system separation, key scheduled and actual flows prior to disturbance and in the case of a disturbance involving a special protection or remedial action scheme, what action is being taken to prevent recurrence:
____
____
____
____
____
____

7. List generation tripped: MW total
____
____

8. Frequency: a. just prior to disturbance Hz
b. immediately after disturbance Hz max. Hz Min.

9. List transmission lines tripped (specify voltage level of each line):
____
____
____

	FIRM	INTERRUPTIBLE
10. Demand tripped	MW	MW
Number of customers affected	Customers	Customers
Demand lost in MW-Minutes	MW-Min.	MW-Min.

11. Restoration time	Initial	Final
Transmission	_______	_______
Generation	_______	_______
Demand	_______	_______

U.S. Department of Energy Disturbance Reporting Requirements

Introduction

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 below. Such report or a part of such report may be made jointly by two or more entities or by a Regional Reliability 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 associated with 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 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 total customers 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 and Public Appeals

2.1. A report is required for any anticipated or actual system voltage reduction of 3% 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 or 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. 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. Control Performance
F. Inadvertent Interchange
G. Control Surveys
H. Control and Monitoring Equipment

Policy 2. Transmission

A. Transmission Operations
B. Voltage and Reactive Control

Policy 3. Interchange

A. Interchange Transactions
B. Interchange Schedules
C. Schedule Specifications
D. Interconnected Operations Services
E. Transfer Capability

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 Overload
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. Operator 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 — Generation
C. Current Day Operations — Transmission

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. Undervoltage Load Shedding
F. Special Protection Systems

IV. System Restoration

A. System Blackstart Capability
B. Automatic Restoration of Load

Appendix C. Disturbances, Demand Reductions, and Unusual Occurrences

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

			Firm Load			
Date	**Region**	**Utilities**	**Type***	**MW**	**Customers**	**Cause**
01/06/98	**NPCC**	**Hydro-Québec**	**INT**	**N/A**	**1,300,000**	**Weather—ice storm**
01/07/98	**NPCC**	**Central Main Power Co., NY State E&G Co., NYPA, Niagara Mohawk Power Corp., Central Vermont PS Co., Northeast Utilities**	**INT**	**1,000**	**600,00**	**Weather—ice storm**
01/08/98	**NPCC**	**Ontario Hydro**	**INT**	**N/A**	**N/A**	**Weather—ice storm**
01/16/98	NPCC	Northeast Utilities, Connecticut L&P Co.	INT	N/A	90,000	Weather — ice storm
01/27/98	SERC-	Carolina Power & Light Co.	INT	150	80,000	Weather — snow storm
01/27/98	ECAR, SERC	American Electric Power	INT	N/A	176,102	Weather — snow storm
02/02/98	FRCC	Florida Power & Light Co.	INT	400	500,00	Weather — high winds
02/10/98	ERCOT	Houston Light & Power Co.	INT	N/A	90,000	Weather — thunderstorms
02/26/98	**SPP**	**Central Louisiana Electric Co.**	**UO**	**N/A**	**N/A**	**Weather — tornado**
03/09/98	MAIN	ComEd	INT	900	290,000	Weather — snow storm and wind
03/31/98	NPCC	New Brunswick Power Corp.	UO	N/A	N/A	Operator error
05/07/98	SERC	Duke Power Company	INT	150	56,000	Weather — thunderstorms
05/11/98	NPCC	Consolidated Edison Co. of NY	INT	N/A	235,000	Inadvertent load shedding
05/13/98	WSCC	Public Service Co. of Colorado, Platte River Authority	INT	545	N/A	Bus support pillar failure
05/15/98	MAIN	ComEd	VR	N/A	N/A	High customer demand
05/18/98	MAIN	ComEd	PA	N/A	N/A	High customer demand
05/15/98	NPCC	Ontario Hydro	VR	N/A	N/A	Loss of generation
05/20/98	SERC	Entergy	PA	N/A	N/A	High customer demand
05/21/98	WSCC	British Columbia Hydro & Power Authority, Transalta Utilities Corp.	INT	618	N/A	Loss of generation
05/27/98	WSCC	El Paso Electric Co., Comision Federal de Electricidad	INT	450	100,000	Maintenance work
05/29/98	ECAR	Consumers Energy Co.	INT	750	700,000	Weather — thunderstorms
05/31/98	WSCC	El Paso Electric Co., Comision Federal de Electricidad	INT	138	N/A	Equipment failure
06/01/98	MAAC	Baltimore Gas & Electric Co.	INT	480	115,000	Weather — thunderstorm
06/07/98	WSCC	Bonneville Power Administration, British Columbia Hydro & Power Authority, Alberta Control Area, West Kootenay Power	INT	972	N/A	Weather — thunderstorms
06/09/98	NPCC	New Brunswick Power Corp.	UO	N/A	N/A	Maintenance work
06/14/98	MAIN	Ameren	INT	N/A	140,000	Weather — thunderstorm
06/16/98	SERC	Alabama Power Co.	INT	500	86,500	Weather — thunderstorms
06/16/98	NPCC	Commonwealth Electric	INT	155	169,719	Equipment failure
06/24/98	SERC	Alabama Electric Cooperative	INT	218	N/A	Loss of generation
06/25/98	**MAPP, MAIN, NPCC**	**Utilities in MAPP, NPCC (Northwestern Ontario Hydro) and portions of MAIN**	**INT**	**950**	**152,000**	**Weather—thunderstorms, Violation of MAPP Operating Standards**
06/29/98	MAAC, MAIN, ECAR	ComEd, Cinergy, Detroit Edison Co., Allegheny Power Co., and others	DR	N/A	N/A	Weather — high temperatures
06/27/98	MAPP	Rochester Public Utilities	INT	130	N/A	Weather — severe storms
06/29/98	MAPP	MidAmerican Energy	INT	750	160,000	Weather — thunderstorms

			Firm Load			
06/29/98	MAPP	Alliant Utilities, IES Utilities Division	INT	500	94,000	Weather — thunderstorms
Date	**Region**	**Utilities**	**Type***	**MW**	**Customers**	**Cause**
06/30/98	SERC	Duke Power Co.	INT	N/A	66,000	Weather — thunderstorms
06/30/98	MAAC	Duquesne Light Co.	INT	350	100,000	Weather — thunderstorm
06/29/98	SPP	Western Resources, Inc.	INT	200	48,000	Weather — thunderstorms
07/03/98	ERCOT	Central Power & Light Co.	INT	350	48,500	Insulator flashover
07/10/98	SPP	Western Resources, Inc.	INT	500	105,000	Weather — thunderstorm
07/14/98	NPCC	Ontario Hydro	UO	N/A	N/A	Failure to recognize contingency situation
07/17/98	**WSCC**	**Public Service Co. of Colorado**	**INT**	**300**	**115,000**	**Tree contact**
07/19/98	ECAR, SPP	Cinergy, Detroit Edison Co., Consumers Energy, Western Resources, Inc.	PA, INT	N/A	N/A	Weather — thunderstorms High temperatures
07/23/98	NPCC	ISO New England	UO	N/A	N/A	High temperatures and customer demand
07/27/98	WSCC	Pacific Gas & Electric Co., San Diego Gas & Electric Co., Southern California Edison Co.	INT	N/A	N/A	High temperatures and customer demand
07/27/98	SPP	City Water Light and Cable, Paragould AK	INT	26	6,100	Weather — thunderstorm
07/29/98	MAAC	Conectiv/Delmarva Power Co.	VR, INT	110	400,000	Weather — high winds unavailability of generation
08/03/98	WSCC	California ISO	PA, INT	N/A	N/A	High temperatures and customer demand
08/12/98	ERCOT	Central Power & Light Co.	INT	350	49,000	Crane contact
08/17/98	MAAC	Atlantic Electric Co.	VR	400	88,000	Loss of generation
08/24/98	MAIN, ECAR	ComEd, Detroit Edison Co.	PA, INT	750	250,000	Weather — thunderstorms high temperatures
08/24/98	NPCC	Consolidated Edison Co. of NY	PA	10,280	N/A	High customer demand
08/26/98	SERC	Carolina Power & Light Co., Virginia Power	INT	2,300	564,500	Weather — hurricane
08/31/98	WSCC	California ISO	PA, INT	N/A	N/A	High temperatures and customer demand
09/22/98	SERC	Entergy	INT	260	24,959	High temperatures and customer demand, tree contact
09/24/98	SERC, FRCC	City Electric Systems, Key West, Alabama Power Co.	INT	450	142,000	Weather — hurricane
10/15/98	NPCC	Hydro-Québec	INT	1,500	N/A	Operator error
11/4/98	WSCC	Arizona Public Service Co., Southern California Edison Co.	INT	N/A	N/A	Equipment failure (relay)
11/09/98	WSCC	Tucson Electric Power Co.	INT	150	86,000	Weather
11/10/98	ECAR, MAIN	Consumers Energy, ComEd, Detroit Edison Co.	INT	N/A	661,000	Weather — thunderstorms and wind
11/10/98	WSCC	Salt River Project	INT	N/A	N/A	Equipment failure (relay)
12/17/98	NPCC	Manitoba Hydro	INT	N/A	N/A	Operator error
12/08/98	**WSCC**	**Pacific Gas & Electric Co.**	**INT**	**600**	**375,000**	**Operator error**
12/23/98	SERC	Duke Energy, Carolina Power & Light Co., Tennessee Valley Authority, Virginia Power	INT	2,000	760,000	Weather — ice storm

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

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