



NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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2002 System Disturbances

Review of Selected Electric System Disturbances in North America

**North American Electric Reliability Council
Princeton Forrestal Village
116-390 Village Boulevard
Princeton, New Jersey 08540-5731**

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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 2002 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.

System Disturbances — 2002

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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, fuel supply problems, and acts of sabotage that can affect the reliability of the bulk electric systems.

NERC's annual review of system disturbance reports is carried out throughout the year by means of periodic conference calls to review all disturbances reported to date. In November, the Disturbance Analysis Working Group (DAWG) meets to review and discuss in more detail each disturbance reported to NERC and DOE so far that year. Preparation of the final report on the selected disturbances is begun early the following year. The DAWG selects reports that it believes to be of value to the industry and then contacts the regional council or utility(ies) involved to request 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 on Pages 5–6.)

In 2002, utilities in the United States and Canada reported 56 incidents of system interruptions, unusual occurrences, demand and voltage reductions, or public appeals. These incidents are listed chronologically in **Appendix B** and categorized as:

- Thirty-eight system interruptions
- One system interruption with voltage reduction
- Fourteen unusual occurrences (no customer interruption)
- One voltage reduction
- One public appeal
- One demand 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 7–8.

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 1. — 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 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

Disturbances by Analysis Category

Operating Policies

Operating Policies	Incident Number				
	1	2	3	4	5
Policy 1 – Generation Control and Performance					
A. Operating Reserve			X		
B. Automatic Generation Control	X		X		X
C. Frequency Response and Bias	X		X		X
D. Time Control					
E. Performance Standards			X	X	X
F. Inadvertent Interchange Standard					
G. Control Survey					
H. Control and Monitoring Equipment					
Policy 2 – Transmission					
A. Transmission Operations	X			X	X
B. Voltage and Reactive Control		X			
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		X	X	X	
B. Operational Security Information				X	
C. Maintenance Coordination	X		X		X
D. System Protection Coordination		X		X	X
Policy 5 – Emergency Operations					
A. Coordination with Other Systems					
B. Insufficient Generating Capacity					
C. Transmission System Relief					
D. Separation from the Interconnection		X		X	X
E. System Restoration		X		X	X
F. Disturbance Reporting					
G. Sabotage Reporting					
Policy 6 – Operations Planning					
A. Normal Operations					
B. Abnormal Operations				X	X
C. Automatic Load Shedding		X		X	X
D. System Restoration		X		X	X
E. Control Center Backup					
Policy 7 – Telecommunications					
A. Facilities					
B. System Operator Telecommunications Procedures					
C. Loss of Telecommunications					
Policy 8 – Operating Personnel and Training					
A. Responsibility and Authority					
B. Training		X			
C. Certification					
Policy 9 – Security Coordination Procedures					
A. Next Day Operations Planning Process					
B. Current Day Operations – Energy		X		X	
C. Current Day Operations – Transmission				X	X

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Planning Standards

Planning Standards	Incident Number				
	1	2	3	4	5
I. System Adequacy and Security					
A. Transmission Systems		X		X	
B. Reliability Assessment			X		
C. Facility Connection Requirements					X
D. Voltage Support and Reactive Power		X			
E. Transfer Capability					
F. Disturbance Monitoring					
II. System Modeling Data Requirements					
A. System Data					
B. Generation Equipment	X		X		
C. Facility Ratings		X			X
D. Actual and Forecast Demands					
E. Demand Characteristics (Dynamic)					
III. System Protection and Control					
A. Transmission Protection Systems		X		X	X
B. Transmission Control Devices		X		X	X
C. Generation Control and Protection	X		X	X	
D. Underfrequency Load Shedding		X		X	X
E. Undervoltage Load Shedding					
F. Special Protection Systems		X		X	X
IV. System Restoration					
A. System Blackstart Capability		X			
B. Automatic Restoration of Load					X

Incident Number

1. AEP 765 kV Equipment Failure — April 23, 2002
2. JEA Equipment Failure — April 29, 2002
3. Multiple Loss of Natural Gas-fired Units — March 20 and July 26, 2002
4. WECC Contractor Accident — August 2, 2002
5. WECC Severe Weather (Ice) — December 26, 2002

Disturbances

1. AEP 765 kV Equipment Failure — April 23, 2002

On April 23, 2002, circuit breaker C at the Rockport 765 kV station on the Rockport-Jefferson 765 kV line was being restored to service following maintenance (see Figure 1). When the breaker was closed, a column disagreement condition occurred, which resulted in a breaker failure relay operation, as designed. This caused system protection to remove from service circuit breakers A1, B1, C2, and transformer bank 7 at Rockport, and B and B1 at Jefferson, causing a lockout of the Rockport-Jefferson 765 kV line. Rockport Generating Plant, with an installed 2,600 MW capacity, was isolated onto the Rockport-Sullivan 765 kV line, which was the only remaining outlet from the plant. Rockport generating plant's two units were operating at a combined output of 2,500 MW. The two 1,300 MW units immediately experienced growing oscillations. After 6.4 seconds, system protection at Sullivan removed the Rockport-Sullivan 765 kV line from service in response to the large voltage and current swings due to the oscillations. Following the loss of the Rockport-Sullivan 765 kV line, system protection removed the two Rockport generating units from service due to over-frequency protection.

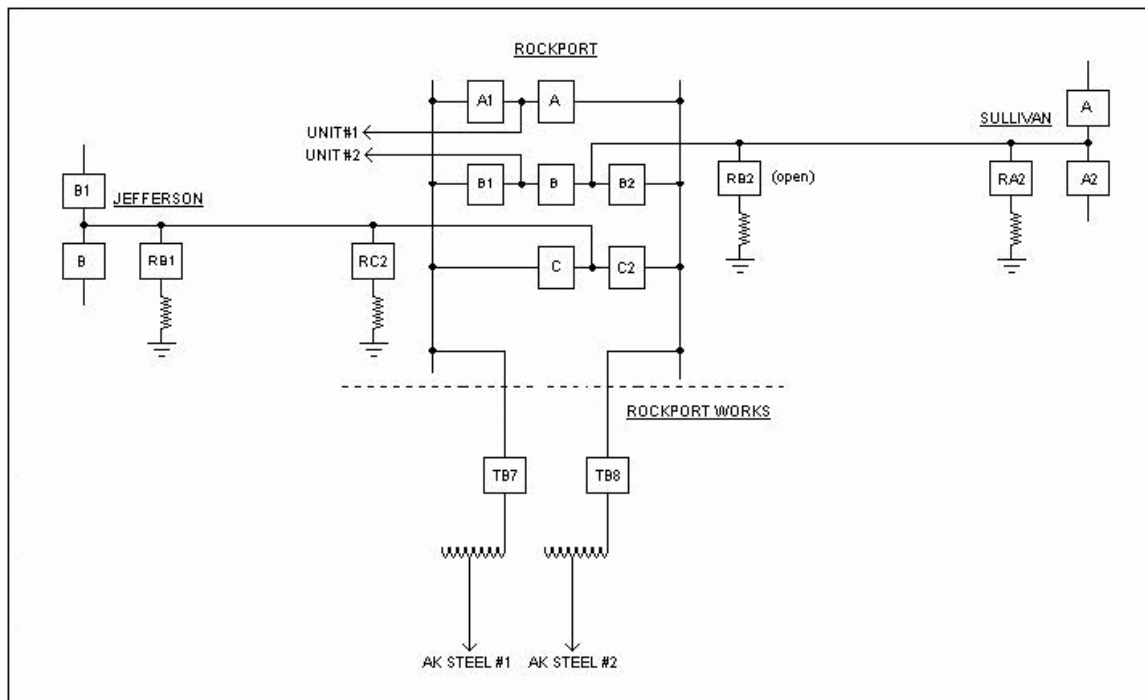


Figure 1: Rockport Area One-Line Diagram

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Sequence of Events

T = 0 sec	Rockport breaker C pole 1 and 2 closed (14:50:17.16) Rockport breaker C breaker failure lockout relay operates (14:50:17.23) Rockport breaker A1 opened (14:50:17.24) Rockport breaker B1 opened (14:50:17.24) Rockport breaker C2 opened (14:50:17.24) Rockport Works breaker TB7 opened Jefferson breakers B1 and B opened (14:50:17.29) Rockport breaker C pole 1 and 2 opened (14:50:17.38)
6.4 sec	Sullivan breakers A2 and A opened (14:50:23.58) Rockport breakers B2 and B opened (14:50:23.64)
6.9 sec	Rockport Unit 2 lockout relay operates (14:50:24.05) Rockport Unit 1 lockout relay operates (14:50:24.07)
20.8 sec	Sullivan breaker A closed (14:50:37.75)
30 sec	Sullivan breaker A2 closed Rockport breaker B2 closed

The un-damped oscillations (see Figure 2) experienced by the Rockport units following the three-phase opening of the Rockport-Jefferson line were unexpected. Therefore, AEP conducted an investigation to identify potential cause(s) for these growing oscillations. Any malfunction or abnormal operation of the excitation equipment was ruled out as a cause since there were no alarms associated with the excitation system, and all the voltage regulators remained in automatic voltage control mode through the incident.

Therefore, in a continuation of efforts to identify potential cause(s), AEP replicated the incident through a series of computer simulations.

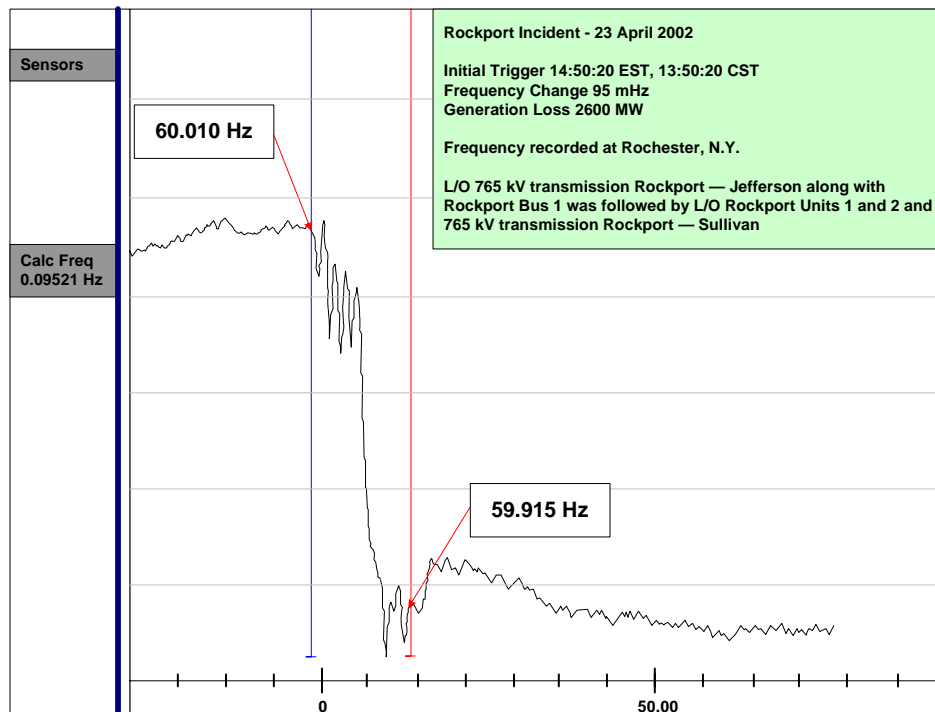


Figure 2 – Rockport Frequency Plot

Replication of April 23, 2002, Rockport Incident

A stability simulation base-case was created to replicate the prevailing steady-state conditions and the sequence of events during the incident. The base-case stability simulation results did not match the response exhibited by the Rockport generating units during the incident. Therefore, sensitivity study simulations were conducted involving what if scenarios such as variations in steady-state conditions and excitation system parameters. The simulation results indicated that with the excitation system automatic voltage regulator (AVR) dc gain of about 120 per unit (P.U.), instead of 80 P.U. used in the base case, the simulated response of the units was similar to the actual response during the incident.

This observation prompted AEP to investigate the AVR settings, which had been implemented at Rockport in April 2000 and April 2001, when the voltage regulators were replaced on both units with new equipment.

Investigation of Rockport Automatic Voltage Regulator Settings

First, AEP reviewed the calculations made by the equipment vendor in converting the AEP-recommended AVR parameters to equipment input parameters. This review indicated that the vendor's interpretation of AVR dc gain value of 80 P.U. was different from AEP's interpretation. This difference stemmed from the fact that in deriving the P.U. value of AVR gain, AEP used the IEEE-proposed approach of following the ac exciter air gap line, whereas the vendor followed the ac exciter loaded saturation curve. A further review of vendor approach to derive the equipment input parameters also indicated a need to test the equipment, as described below.

Testing on Gavin AVR Training Module

In July 2002, AEP performed bench testing on an AVR training module, which is expected to have the same functionality as that of the Rockport AVRs. The testing was performed in a laboratory environment at AEP's Dolan Technology Center on an AVR training module shipped from AEP's Gavin generating plant. The equipment input parameters of this module were set to the same parameters as those set at Rockport.

The testing was done on both components of AVR, the Proportional Integral Derivative controller (PID), and the power amplifier. The testing involved the measurements of the dc gain and frequency response of the PID, and the dc gain of the power amplifier.

Observations and Conclusions

The test data was analyzed to derive the Rockport AVR parameters as set on April 23, 2002. The analysis indicated that the AVR dc gain on Rockport generating units was set at 120 P.U., instead of the desired value of 80 P.U. As mentioned earlier, when this dc gain value of 120 P.U. is used in stability simulations, the simulated performance of the Rockport units matches well with the actual response exhibited by the units on April 23, 2002.

It was also concluded that the AVR dc gain can be adjusted to its desirable value of 80 P.U. by changing one of the equipment input parameters, specifically the ceiling factor, from its current value of 675% to 1,100%.

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Implementation of Solution

The ceiling factor of the AVR equipment of both Rockport units was changed to 1,100% in October 2002. Also, additional adjustments were made in the AVR parameters to further improve the stability performance of the Rockport plant. As part of this implementation, operational commissioning tests were conducted on excitation systems of both Rockport units at no load and full load MW levels. A preliminary analysis of test data confirms the new AVR gain settings. A detailed analysis of these tests was conducted and a digital model of Rockport excitation system equipment has been developed for use in future system dynamics studies.

Petersburg Unit 4 Trip at Indianapolis Power & Light

Also related to this event, a new generator control system at Indianapolis Power & Light's (IPL) Petersburg Generating Station removed from service the 515 MW Petersburg No. 4 Unit about 12 seconds after the start of the Rockport event. IPL had just installed the new generator control system on the Petersburg No. 4 Unit, and it had several settings that were too sensitive. The Rockport event was the first system disturbance to occur since the installation of the new system, during which the power-load unbalance control system element removed the Petersburg No. 4 Unit from service. This element was set too sensitive, with no time requirement for the unbalanced condition to be sustained. These two settings have been corrected. The other three Petersburg units remained on line during the event.

Lessons Learned

This incident underscores the need to have an accurate representation of excitation system equipment in system dynamics studies. This representation is particularly critical for a stability-limited power plant such as Rockport. The representation, in the form of a digital model, should be based on appropriate testing conducted on the excitation system equipment.

At Rockport, extensive excitation system testing was performed in 1989–90, when AEP placed the second Rockport unit in service. From this testing, a need to re-tune the excitation system equipment was recognized, as documented in the IEEE paper, *Benefits of Excitation System Testing at AEP's Rockport Plant*, IEEE Transactions on Energy Conversion, Vol. 6, No. 1, March 1991, pp. 21–28. However, the same level of extensive testing and analysis was not done in April 2000 and April 2001, when the voltage regulators of both units were replaced with new equipment. In the future, more attention will have to be paid in representing excitation system equipment of Rockport and other stability-limited power plants.

2. Jacksonville Electric Authority Equipment Failure

Introduction

On April 29, 2002, the Jacksonville Electric Authority (JEA) transmission system experienced the failure of a 138 kV surge arrester which initiated a chain of events ultimately resulting in separation and islanding of the JEA bulk power system; causing tripping of all JEA generation in the islanded area and the interruption of nearly all JEA native load.

Disturbance Summary

At 15:50:56, on April 29, 2002, the JEA transmission system experienced a failure of a 138 kV surge arrester on their Pickettville-Normandy transmission line which initiated a chain of events ultimately resulting in separation and islanding of the JEA bulk power system causing tripping of all JEA generation in the islanded area and the interruption of most of all JEA native load. Most of JEA's 365,000 customers were affected, including approximately 175,200,000 customer minutes of firm load interrupted and 1,392 customer minutes of non-firm load. The island formed by the separation at Florida Power & Light's (FPL) Millcreek-Sampson line, JEA's Firestone-Black Creek tie, and JEA's two Normandy-Brandy Branch transmission lines included all of JEA's native load and substations (with the exception of Steelbald substation and load), the City of Jacksonville Beach native load, FPL load at Orangedale, and a portion of the Seminole Electric Cooperative (SEC) (Clay) Black Creek substation load.

Prior to the event, conditions were nominal. Weather conditions were moderate, JEA was importing 130 MW to assist in serving its system load, and transmission voltages were all normal. Transmission voltages during the initial phase of the disturbance, prior to the islanding and collapse, were somewhat reduced, ranging from about 5–7% low. After collapse of the island, the voltage and frequency were zero.

System restoration began at 16:26:03. By 18:21, the Firestone-Black Creek tie, the Normandy-Brandy Branch lines, and over 1,200 MW of load had been restored. At 18:22, both of the Normandy-Brandy branch lines tripped again, the system separated and islanded a second time, and all JEA load (except Steelbald) and the SEC load was lost again. Restoration began again at 18:31. By 01:30, April 30, 99% of the load had been restored, and the system was essentially normal.

The disturbance was the result of a concurrence of seven, not entirely independent, events:

1. The failure of the surge arrester (weather and system conditions were nominal at the time of failure).
2. The coincident incorrect tripping of one of two Normandy to Brandy Branch circuits at Brandy Branch due to a relay wiring/design error.
3. Metering saturation on the (second) parallel Normandy to Brandy Branch line, resulting in under-indication of line flow. Operators perceived an acceptable line loading of approximately 104% rated capability. Loading was actually around 118 %, resulting in excessive conductor sag. This was a major factor in both the initial and the second collapse.
4. Tree interference of the Normandy to Brandy Branch lines when the lines were loaded above nominal rating.
5. Tripping of St. Johns River Power Park #2 generator at 16:22 when an attempted closing of the first Normandy to Brandy Branch circuit resulted in a rapid phase angle change. Operators were unaware of the phase angle magnitude, which had not been previously identified as a potential problem.
6. Apparent misoperation of the Black Creek out-of-step protection.

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7. Failure of Northside and Kennedy combustion turbine's to come on-line prior to the first separation. Communication and coordination among Florida utilities, and particularly the Florida Reliability Coordinating Council (FRCC) SC and JEA operators was extensive and very effective. Although SCADA data available to the FRCC SC was delayed by as much as two minutes (this was reduced to 10 seconds in August 2002), the JEA operators were quick to respond to all SC questions, and receptive to SC suggestions. The SC attempted to provide pertinent information such as total import capability into the JEA system and impact on other systems such as line loadings, voltages, and status of feeds into JEA. The SC had Florida Power and Light and Florida Power Corporation regulate to the FRCC Area Control Error (ACE) to allow JEA to pickup load as required, without adversely impacting the Eastern Interconnection and the maximum state import first contingency limit.

Following the disturbance, JEA operators were interviewed with regard to their compliance to NERC Policy 5 — Emergency Operations, and FRCC Restoration Standards. The focus was on transmission system relief actions from the initial arrestor failure to the actual blackout, separation from the interconnection actions, and system restoration actions. Each step was reviewed in light of the requirements and guides in Policy 5 and Restoration Standards. JEA operators were determined to be in full compliance.

The FRCC SC provided information to JEA operators as requested. Upon the first separation, the SC restored power to FPL's Orangedale Substation and to FMPA's Ft. Diego Substation feed to Jacksonville Beach within three minutes, and stood ready to provide power to JEA from the south to the JEA Greenland Substation, and from the west out of Duval Substation into Brandy Branch Substation. The SC insured that the Florida grid, especially areas surrounding JEA, remained secure at all times, even at the 3,600 MW Florida state import limit.

Just prior to the disturbance, JEA had approximately 1,729 MW (83% of actual load) covered by under-frequency relays, steps A-N. Assuming 58.0 Hz as the point at which generation tripped, the control area should have shed steps A-F, which is 41% load, or 854 MW. SCADA records indicated that 98 feeder breakers serving 862 MW did trip. Seven feeder breakers (about 70 MW of load) which, according to the schedule, should have tripped in steps A-F, failed to do so. Nevertheless, the control area tripped about 8 MW more than the minimum required.

Lessons Learned and Remedial Action

By December 31, 2002, a report was made to the FRCC Operating Reliability Subcommittee addressing the resolution of the specific recommendations included in the detailed report associated with the "lessons learned" below. As a matter of policy, based on an under-frequency load-shedding event, the FRCC reviewed the region's under-frequency relaying program, and determined the program remains appropriate.

1. A thorough study of the power angles which develop when lines are open should be conducted by JEA so that this issue is fully understood by planning and operating personnel, and appropriately addressed in planning and operating policies and procedures. This should also assure there are no detrimental effects propagating into neighboring systems.
2. Switched-on-to-fault logic on the Normandy to Brandy Branch circuits backup relays, which has been temporarily disabled, should be re-evaluated after completion of #1 above, and either re-set, or permanently disabled as appropriate.
3. Conduct a review of all JEA RFL 9300 installations to ensure the proper connections of status inputs, thereby addressing the relay wiring error discovered.

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4. Immediately review all transmission right-of-way clearances, and take whatever emergency action is required to ensure proper clearances.
5. Review and revise, as necessary, policy and procedures for inspecting and ensuring clearance of transmission right-of-way.
6. Review the St. John's River Dover Park Power-Load-Unbalance (PLU) settings, and ensure coordination with #1 above. It may be possible, or desirable, to reduce the "sensitivity" of the PLU settings, and still maintain the appropriate protection of the units.
7. Review and correct, as appropriate, the combustion turbine synchronizing systems. It is important that these units have the ability to synchronize with the power system under as wide a variety of conditions as possible.
8. Inspect and test the Black Creek line protection and out-of-step relaying for correct setting and proper operation.
9. Review and modify as necessary, the SJRPP generators under-frequency tripping schemes, to eliminate the possibility of leaving generator breakers closed after a turbine trip (given a de-energized transmission system). While not contributing to the disturbance, SJRPP generator breakers status following isolation, represented significant risk to the generator upon system restoration absent manual intervention.
10. Review and correct, as necessary, the metering design for transmission lines to eliminate possible saturation during credible operation beyond nominal line rating.

3. Multiple Loss of Natural Gas-Fired Units — March 20 and July 26, 2002

July 26 — Collins, Illinois

On July 26, 2002, the 2,500 MW natural gas-fired Collins generating station west of Chicago, in the MAIN region, experienced a brief pressure excursion on its gas supply system while efforts were underway to isolate a leaking flange. This pressure spike caused four of the five 500 MW units to trip off-line in a period of 36 seconds, resulting in a total station generation loss of 2,019 MW at approximately 1520 CDT. Although the size of this contingency was far greater than the area's recognized first contingency loss, initiation of MAIN's Reserve Sharing System along with other reserve activation measures succeeded in returning the Area Control Error to its pre-disturbance value in 16 minutes.

Discussion — Collins Event

Prior to the disturbance, the five Collins generating units were operating normally at approximately 490 MW each. Personnel arriving at the station for a shift change noticed and reported to the operators, what appeared to be a cloud of smoke coming from a building in the gas yard that supplies the station. Plant staff immediately notified the local gas supply company to have personnel come to the site as soon as possible to investigate the situation. Within approximately a half-hour, three gas company employees arrived on-site and began their investigation. They found that a metal flange gasket had blown on one of the gas regulating runs to the units and the resulting leak had formed a dust and gas cloud. Because the cloud was blowing toward pipeline heaters, the employees took immediate steps to valve into service a redundant regulated gas run. Following this, they isolated the leaking run for repairs. During the period when the redundant run was switched into service, its gas regulator overreacted, causing the gas line pressure to fluctuate from 150 psi to 30 psi and then back to 150 psi. This fluctuation caused an immediate flame stability problem on the five Collins units, triggering manual reductions totaling 295 MW in an effort by the operators to bring the unit boilers into equilibrium. One minute later, the units began to rapidly runback to zero output (by Gas Fuel System protection) over a period of 36 seconds:

15:19:52 Unit 3 from 433 MW

15:20:00 Unit 1 from 411 MW

15:20:10 Unit 2 from 441 MW

15:20:28 Unit 4 from 439 MW

Only Unit 5 was able to ride through the gas pressure transient and remain on line. The total generation loss at Collins was 2,019 MW including 1,724 MW lost in the brief 36-second period. The maximum ACE resulting from the station upset was -2,098 MW. This was countered by initiation of the MAIN Reserve Sharing System requesting the maximum amount of emergency energy available, activation of Commonwealth Edison (ComEd) spinning reserves, and ordering start-up of all available ten minute generators under ComEd control. The ComEd ACE returned to its pre-disturbance level during the 16 minutes following the disturbance. Following confirmation that the station gas system was stable, all Collins units were returned to full operation by 16:33 hours.

March 20 — Fort McMurray, Alberta

On March 20, 2002, the Fort McMurray area in the northern Alberta portion of the WECC region, while operating with only one of its two 230 kV system tie lines in-service, became "islanded" and experienced

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the loss of 274 MW of load. The disturbance was initiated by the loss of one of two boiler feed water lines at a 2x125 MW gas-fired station in the Fort McMurray area. This incident led to the tripping off-line of five gas-fired generators (loaded at 390 MW) located at four different stations, over a five minute 20 second period. The resulting import power flow into the area, combined with insufficient local voltage support caused a 230 kV tie line to trip. The 230 kV tie to the Alberta power system was restored after 17 minutes to allow restoration efforts to begin.

Discussion — Fort McMurray Event

Prior to the event, one of two 230 kV ties (Ruth Lake to Mitsue) from Fort McMurray to the Alberta Power Pool system was out of service for planned rebuilding work scheduled to last fourteen days (this was day 13 of the scheduled outage). Total generation on-line in the area was 665 MW with 145 MW of this leaving the area on the remaining 230 kV tie (Ruth Lake to Whitefish Lake).

At 10:14:28 hours MST, Suncor generator GT6, one of the two largest units on-line in the Fort McMurray area, tripped while at 123 MW output due to loss of its heat recovery steam generator (HRSG). The loss of the HRSG was the result of an earlier loss of one of two boiler feed water lines, which in turn, caused low water levels in the HRSG of both units GT6 and GT5. Twenty-eight seconds after the GT6 trip, GT5 also tripped while at 121 MW output. The loss of steam from the two HRSG also affected three other Suncor generators at three different stations, leading to a gradual decay in their output power:

10:16:59 TG3 had dropped from 57 MW to zero
10:19:48 TG4 (Tar Island) had dropped from 64 MW to zero
10:19:48 TG2 (Steeptank River) had dropped from 26 MW to zero

Seven seconds later, the single 230 kV tie line tripped by both of its sets of distance protection at Ruth Lake (receiving end) due to low voltage and over 1,200 amps of current, caused by the loss of generation and voltage support in the area. The “islanded” Fort McMurray system then split into sections as special protection systems and underfrequency load shedding actions took place. Total load lost was 274 MW out of the 520 MW being served in the area. The 230 kV line at Ruth Lake was restored at 10:37 hours to allow the start of full restoration activities. The final substation was energized at 11:05 hours and area generation was gradually returned to normal over a period of days.

Conclusions

The recent technological advances that have allowed natural gas-fired generators to assume an increasing role in the generation of electric power have also brought concerns to the industry. The primary concern regarding the vulnerability of these stations to a single point of failure on the gas pipeline system or even curtailment of supplies during high gas usage periods, have led to extensive wide-area studies in various parts of the network.

The two disturbances summarized in this report reveal that there are other smaller, but nonetheless serious, hazards to be wary of when dealing with natural gas-fired generation. The Collins event shows that a failure, even within the gas distribution equipment of a single plant, can produce a generation source loss contingency that is much higher than the anticipated first contingency level. Similarly, the Fort McMurray event demonstrates another method whereby a single point of failure, the steam supply system, can multiply its effects such that several units can be affected.

In both cases a single mishap, even though handled correctly by the involved parties, resulted in multiple generating unit trips.

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For more information on these events, contact the Mid-America Interconnected Network, Inc. (MAIN) and the Western Electric Coordinating Council (WECC).

4. WECC Contractor Accident — August 2, 2002

On Friday, August 2, 2002, an electric utility (Utility A) in the southeastern portion of the Western Interconnection experienced a major disturbance on its electrical system. At approximately 0947 MDT, a sub-contractor who was involved in the construction of a third party generating station interconnection expansion facility at Substation A, raised the bed of his dump truck to the point that caused the Substation A-Substation B 345 kV line to flash phase-to-ground just outside Substation A.

Before the incident, Utility A had roped off certain areas inside the Substation A as a precautionary measure against personal injury. Additionally, an observer was stationed in the substation near the contract site to prevent contact of energized equipment and to ensure that safe practices were being followed. These precautions were taken inside the substation because of the reduced ground clearance that exists there. Outside the station ground clearance complies with the National Electrical Safety Code requirements for over land vehicle access. For this reason, no extra ordinary measures were taken.

Fault records indicate that the resulting short circuit on the Substation A-Substation B 345 kV line was a B phase-to-ground fault approximately 200 feet from Substation A. Protective relays on that line correctly sensed the fault and opened the line at both ends.

Simultaneously, the Substation A-Substation C 345 kV line tripped at the Substation C end due to a relay misoperation.

Approximately two seconds later the combined cycle generator, Unit No. 4 at Generating Station A, tripped due to loss of fuel and condensate pump failure as well as operation of a reverse power relay. Almost concurrent with this trip, the HVDC terminal at Converter Station A experienced a sequence of commutation failures and recoveries that eventually led to the commutation failure of the terminal. Three seconds later Generating Station B Unit No. 8 (69 MW) tripped off line due to reverse power relay.

Concurrently, the Utility A system experienced severe voltage degradation which caused Utility A's third 345 kV tie, the Substation D-Substation E tie, to trip via the Phase Shifting Transformer (PST) impedance relays. Loss of the Substation D-Substation E 345 kV tie caused the 115 kV tie line between Utility B and C to trip on out of step. With all 345 kV tie lines open, the remaining Utility A local generation could not supply the system load and required reactive support resulting in a severe voltage collapse and subsequent loss of Utility A local generation and load.

Prior to the disturbance, the Utility A system was operating normally and 1,071 MW of load was being served through a combination of local and remote generation. Utility A imports totaled approximately 650 MW, which contributed to an overall area import level of 864 MW. This loading was well within the 906 MW nomogram capability that was calculated as available. Utilities B, C, and D received import power above Utility A's approximate 650 MW of imports. An additional 104 MW was being brought over the Utility A-Utility D eastern HVDC tie line, of which 82 MW was Utility A's and 22 MW was Utility D's. Generation Station A Units 1, 3, and 4, and Generating Station B Units 7 and 8 provided total local area generation of 317 MW.

Background

The area transmission system had previously experienced disturbances similar to the one that took place on the morning of August 2, 2002. These disturbances, which occurred in 1995 and 1996, were caused by the trip of a 345 kV line and the subsequent tripping of other major tie lines due to either relay misoperations or procedural error.

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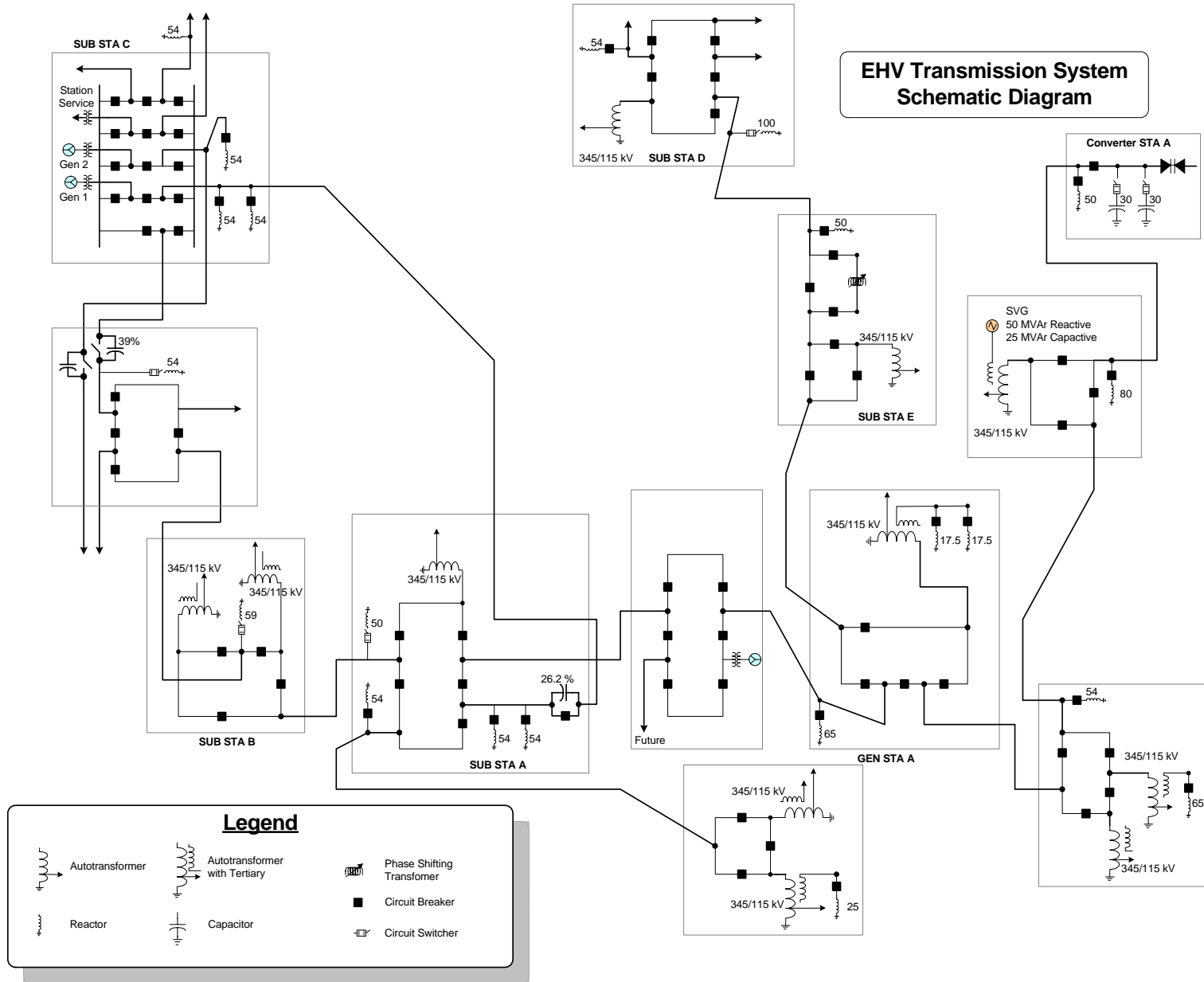
In an effort to alleviate the false-trips that initiated the disturbances of 1995 and 1996, the Area Transmission Relay Subcommittee recommended that a voting scheme with three new protective relay packages per terminal be installed. These voting schemes, which have been installed since then, are comprised of three independent relay sub-systems that “vote” through a microprocessor device. If all three sub-systems are in service, tripping is restricted unless at least two sub-systems “vote” to trip. These schemes were installed to provide a high level of protection against “false tripping”; i.e., tripping for a fault on a line segment other than the one the relays are intended to protect.

Utility A sent relays of the same models as were implemented in these schemes to a relay manufacturer and had the settings tested with a simulator before placing these schemes into service. Simulation results did not identify any setting problems once settings were finalized, even though it is now evident that the simulations did not adequately model all aspects of the protective relaying application. Utility A has previously experienced many faults on the system with appropriate tripping by these voting schemes.

Impact of Disturbance

The system-wide disturbance of August 2, 2002, caused a disruption of service to Utility A’s 309,000 customers living within its service territory. Utility C reported losing 9,860 customers (25 MW) in its area for approximately four minutes. Also reported was that Utility D had 29,500 customers (38.5 MW) that lost power. Utility E reported loss of approximately 29 MW of customer load in its region. When the length of outage time was considered, the impact translated to 168,925 MW minutes of lost load. During the initial restoration, Utility A reported their EMS failed momentarily and automatically restarted on two separate occasions; at 09:47:04 (a three minute failure) and 09:54:29 (a 15 second failure). The restarts were attributed to the large volume of alarms being processed at these times.

System Disturbances — 2002



Conclusions and Recommendations

Conclusion 1:

Prior to the disturbance, Utility A was operating within WECC Minimum Operating Reliability Criteria guidelines.

Conclusion 2:

NERC Policy 5, Section A, on Coordination with Other Systems was not complied with and was a factor in this disturbance. During the restoration, utility system operators throughout the region that failed to communicate with each other prior to energizing circuits, closed circuits to parallel their utility with an adjacent utility and during load restoration.

Recommendation a:

The management of the three involved utilities shall review with their personnel the WECC Interconnected Disturbance Assessment and Restoration Guidelines, and shall review their internal communications and coordination procedures between neighboring systems regarding the energizing of interconnection facilities and restoration of load.

Recommendation b:

The reliability coordinator shall establish a process of communicating with all entities within the coordinator's jurisdiction to provide timely system conditions and status updates during major disturbances, and shall coordinate system restoration activities with them.

Recommendation c:

The reliability coordinator shall establish or review existing procedures to ensure WECC entities are provided timely status updates of abnormal system events and the subsequent restoration activities. These updates may be provided either through the use of the WECC Net or other measures of communication.

Conclusion 3:

The initiating event for this disturbance was a B phase-to-ground fault on the Substation A-Substation B 345 kV line caused by a dump truck. Protective relays on the Substation A-Substation B 345 kV line operated properly by clearing the fault in three cycles.

Recommendation:

Utility A shall review their construction procedures involving the performance of construction work near an energized overhead conductor and make appropriate changes as required.

Conclusion 4:

The prime cause of the disturbance was the simultaneous misoperation of two of the three protective relay sub-systems within the three-relay voting scheme. The three-relay voting scheme package at each end of the transmission line consists of the following distinct relay sub-systems: A Siemens 7SA513 Distance Relay, an ABB REL 350 Segregated Phase Comparison Relay, and a Schweitzer SEL-321 Distance Relay.

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The Siemens Distance Relay sub-system incorrectly voted to trip due to a setting error at one of the terminals. This “distance relay” is set to trip instantaneously for faults along the nearest 85% of the line. However, the setting did not account for the use of a series capacitor in the line section and therefore overreached the Substation A terminal whenever the series capacitor was in service. Note that the Schweitzer SEL-321 Distance relay was set correctly to account for the series capacitor.

The ABB phase comparison sub-system misoperated due to the application of a telecommunication link delay beyond the capability of the relay algorithm. Installation testing did not reveal any time delay problems. The assumption is that there was an unreported change in one or both of the commercial telecommunications circuits between the time of installation and the fault on August 2. The ABB phase comparison relay failed to provide proper alarming of a time delay outside of the relay capability.

Recommendation a:

Utility A shall investigate the cause of the Siemens Distance Relay setting error and put in place a process to prevent reoccurrence.

Recommendation b:

Utility A shall investigate the cause of the ABB Phase Comparison Relay malfunction, and take corrective measures to prevent reoccurrence.

Recommendation c:

Utility A shall review and verify all relay settings on the voting scheme relays on its 345 kV transmission lines.

Recommendation d:

Utility A shall ensure that all telecommunication channel delay times for all 345 kV lines meet the requirements for each relay manufacturer; especially the ABB REL 350 phase comparison relay with the new information provided by ABB and confirms correct operation using improved installation testing.

Conclusion 5:

After the first two 345 kV lines cleared, Generating Station A unit 4 and Generating Station B unit 8 tripped, which resulted in the PST impedance relays tripping the third 345 kV line. The system could no longer be maintained due to a severe load/generation imbalance. Some under-voltage relays with time delays of less than six seconds operated, however, many did not initiate because of time delay settings greater than six seconds. Had the 345 kV PST stayed in service for a longer period of time, Utility A believes the under-voltage relay schemes would have dropped sufficient load and prevented the complete outage.

Recommendation a:

An investigation shall be conducted as to why the system collapsed in six seconds following the loss of two 345 kV lines.

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Recommendation b:

Utility A shall perform an evaluation of the protection scheme used by the PST, and shall implement those modifications considered essential for system stability. Utility A shall also review the settings and operation of the PST relays to verify that they operated correctly.

Conclusion 6:

Utility A's Generating Station A and Generating Station B units tripped within two seconds and five seconds respectively.

Recommendation a:

Utility A shall investigate the reason that these generators tripped so early in the disturbance, and shall implement those modifications considered essential for system reliability.

Recommendation b:

Utility A shall verify that the remaining unit trips were correct and that all of their units are in compliance with WECC generator testing requirements.

Conclusion 7:

During the disturbance, the Utility A EMS experienced two automatic restarts as a result of the high volume of system alarms being processed.

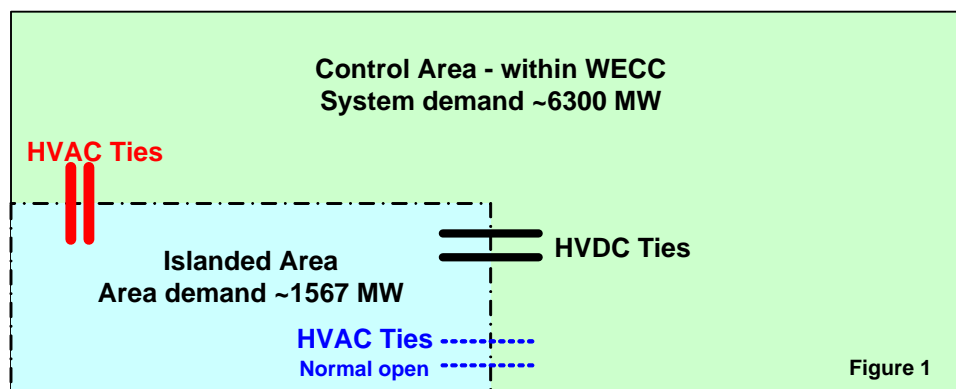
Recommendation:

Utility A shall ensure that the acceptance testing for the new EMS system will include testing that demonstrates adequate high-volume alarm processing functionality.

5. WECC Severe Weather (Ice) — December 26, 2002

Introduction

On December 26, 2002, at 12:02 PST, a portion of a control area within the Western Interconnection lost its synchronous connection to the Interconnection resulting in an asynchronous island. (See Figure 1)



Pre-Disturbance System Conditions

There was a severe rain and ice storm in the region at the time. Prior to this event, the control area demand was approximately 6,300 MW. The portion of the control area that islanded had an internal demand of approximately 1,567 MW, which was being supplied as follows:

- 223 MW from an internal qualifying facility (QF) generating station*
- 423 MW from internal hydro generation
- 360 MW import from two high-voltage ac transmission lines*
- 561 MW import from a two pole high-voltage dc transmission line
 - 234 MW import on Pole 1*
 - 327 MW import on Pole 2

*Indicates the resources lost during the disturbance.

The affected area has two high-voltage transmission lines normally in service, which are used to import generation into the area. In addition, a high-voltage dc transmission line serves the area. Two additional lower-voltage transmission lines (see Figure 2) feed into this area. However, the normal system configuration is to leave these two transmission lines open. These are older circuits, which are near end-of-life.

Before the disturbance, one of the high-voltage transmission lines between Station C and Station M was out of service to repair several damaged towers, which were damaged on December 12, 2002.

All units internal to the affected area were in service except for one unit, which was off-line and on stand-by due to water conditions. The export from the control area to the Interconnection was being ramped from 324 MW to 452 MW. The Interconnection's frequency was normal.

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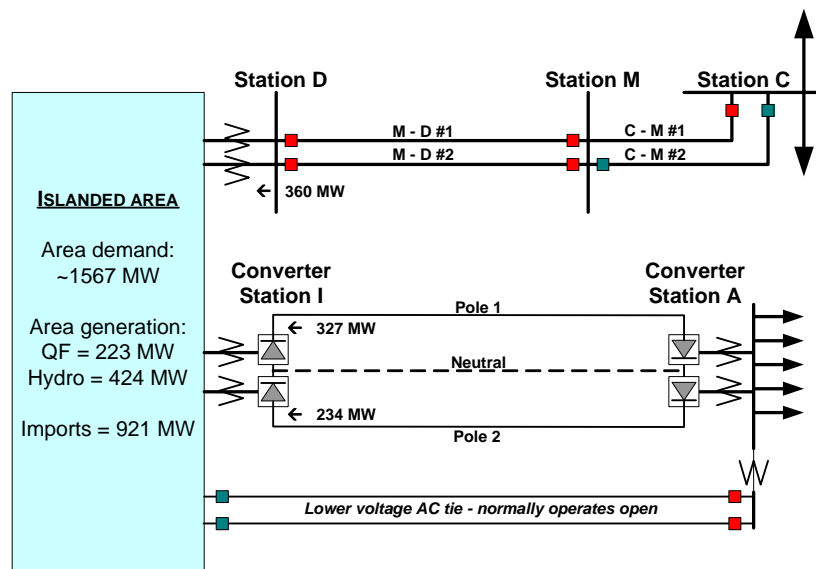


Figure 2 - Transmission connections to the islanded area

Disturbance

On December 26, 2002, at 12:02 PST, system protection removed from service the Station C-Station M #1 high-voltage transmission line due to conductors contacting a tree. The lack of clearance was caused by an extreme increase of conductor sag between towers due to an unequal build up of ice on the conductors in adjacent spans.

As a result of this event, the ac supply into the affected portion of the control area was lost. By design, the circuit breakers at Station M remain open to de-energize the two circuits between Station M and Station D, due to equipment special requirements. This portion of the control area continued to be supplied by the asynchronous high-voltage dc transmission line and internal generation. However, the area was generation deficient.

The loss of the 360 MW being supplied to the affected area by the high-voltage transmission lines caused the area's frequency to decline to 58.516 Hz. As a result of the frequency decline, automatic underfrequency load shedding occurred in the affected area, which shed 460 MW of customer load. This over-shedding caused the islanded area's frequency to rise to 62.138 Hz, which caused system protection to remove from service 223 MW of QF generation by overfrequency protection.

Upon the loss of the 223 MW of QF generation, the islanded area's frequency again declined to 58.171 Hz, which initiated an additional 302 MW of underfrequency load shedding. Following the second round of load shedding, the islanded area's frequency increased to 64.408 Hz, which caused system overfrequency protection to remove from service Pole #1 of the high-voltage dc transmission line, which was supplying 234 MW of energy into the islanded area. The loss of Pole #1 caused the islanded area's frequency to again decline to 57.798 Hz, which initiated an additional 100 MW of underfrequency load shedding.

As a result of the incident, approximately 950 MW of the control area's demand was lost. A total of 862 MW of customer demand was internal to the islanded area, and the remaining 88 MW was bordering the affected area. Approximately 140,000 customers were interrupted because of this event. In addition, system protection removed from service another QF generator (63 MW) during the event.

Restoration

At 12:15 PST, one of the normally open high-voltage transmission lines was placed in service, which synchronized the islanded area to the Interconnection. At 12:17 PST, the second normally open high-voltage transmission line was placed in service. At this point, the control area began restoring its customer load. At 12:29 PST, Pole #1 of the high-voltage dc transmission line was restored to service. At 15:13 PST, the original faulted high voltage transmission line (Station C-Station M Line 1) was restored to service after trimming 20 trees in the area of the fault. Shortly after, the two high-voltage transmission lines between Station M and Station D were restored to service. This action completed the restoration of the area's bulk transmission system feeding into the affected area.

All customer loads within the affected area had been restored within 36 minutes of the start of this event. The control area restored the 88 MW of customer loads bordering the affected area within 60 minutes. After the bulk transmission system was normal, the control area notified all industrial customers to restore their loads.

Conclusions and Recommendations

Conclusion 1:

The control area was operating within WECC's Minimum Operating Reliability Criteria (MORC).

Conclusion 2:

NERC Policy 5, Section A, on coordination with other systems was not a factor.

Conclusion 3:

NERC Policy 6, Section B, on emergency operation plans was not a factor.

Conclusion 4:

The affected area of the disturbance experienced severe frequency swings following the loss of a single high-voltage transmission line and subsequent underfrequency load shedding.

Recommendation a:

Review the performance of the Underfrequency Load Shedding (ULS) system, seek alternative methods to improve performance, and implement necessary changes.

Status:

The control area had proposed setting changes to the ULS system to shed load in smaller blocks and finer increments. Dynamic simulation of the proposed change will be conducted for validation. The overall ULS system will also be reviewed to ensure the proposed change will not negatively impact the performance of the system.

Other mid-term plans that will improve internal system reliability and/or system performance under islanding conditions are being examined or implemented by the control area's planning, engineering, and operating staff. Other mid-term plans include various overload Remedial Action Schemes (see Conclusion #5), an HVDC Pole 2 automatic frequency control mode (see Conclusion #6 below), increasing the QF generator overfrequency setting

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from 62 Hz (see Conclusion #7 below), the HVDC Cable 9 Replacement Project to increase the HVDC transfer capability (expected in service by fall 2003), and single-pole reclosing for high-voltage transmission lines between Station C and Station M (expected in service by 2003 and 2004).

Long-term plans for improving the affected area's system frequency performance under islanding conditions include direct load shedding for loss of normal high-voltage ac supply into the affected area. The decision to proceed will depend on the results of the short-term and mid-term plans for improving area reliability and system performance. System planning is also actively examining options for reinforcing the affected area's supply.

Recommendation b:

Review implementation of frequency overshoot load restoration as specified in the WECC Off-Nominal Frequency Load Shedding and Restoration Plan.

Conclusion 5:

The normally open high-voltage transmission circuits' overload Remedial Actions Scheme (RAS) did not operate as expected during cold load pickup, which caused the flow on the circuits to exceed their rating.

Recommendation:

Investigate and repair the overload RAS.

Status:

An investigation found that the settings for the RAS were incorrect. New settings have been implemented and the circuits were put on-load on January 6, 2003, to calibrate and verify settings.

This recommendation is considered resolved.

Conclusion 6:

The HVDC Pole #2 Automatic Frequency Control mode was not activated as expected (at ± 0.5 Hz frequency deviation). If the control mode had worked as designed, it would have reduced the load that was shed.

Recommendation:

Investigate and repair HVDC Pole #2 automatic frequency control mode.

Status:

An investigation found a wiring problem with the control. The problem has been repaired, and the automatic control mode has been tested.

This recommendation is considered resolved.

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Conclusion 7:

The QF generator tripped at 62 Hz causing additional underfrequency load shedding. If the QF overfrequency protection setting were higher, it would improve area frequency performance.

Recommendation:

Coordinate with the QF to examine the possibility of increasing its overfrequency protection setting. Note: The WECC Off-Nominal Frequency Load Shedding and Restoration Plan only specifies a setting greater than 61.7 Hz for instantaneous tripping of generators.

Status:

Control area operating personnel met with the QF on January 15, 2003, to propose a time-delay setting for QF units to trip at higher frequency. The QF operators will review the proposed settings and advise if a change to the overfrequency relay trip set point is acceptable from a plant design perspective. The QF operators will perform this review on an urgent basis.

Conclusion 8:

The ac supply to the affected area was lost when one of the high-voltage transmission lines between Station C and Station M tripped as a result of a flashover to a tree. Circuit breakers at Station M had been intentionally left open so that the loss of this circuit would result in de-energizing the 500 kV circuits between Station M and Station D. The two other lower-voltage transmission lines feeding into the area are normally operated with one terminal end opened.

Recommendation:

The control area should review the practice of leaving these lower voltage circuits open-ended when one of the high-voltage circuits between Station C and Station M is out-of-service.

Status:

The control area had reviewed the open-ended operation of these circuits. The recommendation is considered resolved.

For more information on this disturbance, please contact the WECC regional reliability council office (at the time of this disturbance WECC was WSCC).

Appendix A

NERC Disturbance Reporting Criteria

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(ies) shall then provide timely, periodic verbal updates until adequate information is available to issue a written preliminary disturbance report.

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- 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

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 email (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 $\pm 10\%$, 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.

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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.

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This is a Word Form. Use the tab key for each data field.

Check here if this is an Operating Security Limit violation report.

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

B. 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?	Yes <input type="checkbox"/> No <input type="checkbox"/>	
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)		
10.	Demand tripped and number of customers affected Demand lost in MW-Minutes	FIRM	INTERRUPTIBLE
		MW	MW
		Customers	Customers
		MW-Min.	MW-Min.
11.	Restoration time	INITIAL	FINAL
	Transmission		
	Generation		
	Demand		

C. 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 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 three % 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:

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- 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 act(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.

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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
01/30-31/02	SPP	Oklahoma Gas & Electric, Kansas City Power & Light Co., and Missouri Public Service Co.	INT	1,210-1,310	570,000	Weather – ice storm
02/27/02	NPCC	Independent Electricity Market Operator	INT/VR	0	0	Equipment failure
02/27/02	WECC	San Diego Gas & Electric Co.	INT	340	210,882	Human error
02/28/02	WECC	California Independent System Operator	DR	0	N/A	Broken static wire
03/09/02	ECAR	Consumers Energy Company	INT	190	190,000	Weather – severe storm
03/09/02	NPCC	Independent Electricity Market Operator	INT	196	46,000	Weather – strong winds
03/20/02	WECC	Power Pool of Alberta	INT	274	17,000	Equipment failure
03/21/02	NPCC	Hydro-Québec – TransÉnergie	UO	0	0	Human error
03/25/02	NPCC	New Brunswick Power Corp.	UO	0	0	Logging activity
03/30/02	SERC	Georgia Power Company	UO	0	0	Weather – lightning & system protection misoperation
04/17/02	WECC	Arizona Public Service Co.	UO	0	0	Equipment failure
04/23/02	ECAR	American Electric Power and Indianapolis Power & Light Company	INT	39	1	Equipment failure
04/27/02	MAPP	Manitoba Hydro	UO	0	0	Equipment failure
04/29/02	FRCC	Jacksonville Electric Authority	INT	2,100	360,000	Equipment failure
05/13/02	SERC	Duke Energy Corporation	INT	175-250	74,000	Weather – severe thunderstorms
06/06/02	WECC	California Independent System Operator	UO	0	0	Wild fires
06/18/02	WECC	B.C. Hydro & Power Authority	INT	334	19,000	Weather – suspected lightning
06/26/02	WECC	California Independent System Operator and Southern California Edison Company	INT	1,450	460,000	Wild fires
07/03/02	NPCC	New Brunswick Power Corporation	INT	210	65,000	Ground fault, equipment failure
07/09/02	FRCC	Lake Worth Utilities	INT	32.8	18,351	Weather – lightning and equipment failure
07/09/02	FRCC	Lake Worth Utilities	INT	48	25,000	Equipment failure
07/15/02	FRCC	Lake Worth Utilities	INT	83	25,000	Equipment failure
07/20/02	NPCC	Consolidated Edison Company of New York, Inc.	INT	278	63,500	Transformer fire
07/26/02	MAIN	Commonwealth Edison Company	UO	0	0	Equipment failure
07/27/02	WECC	Arizona Public Service Company	INT	15	1,000	Weather – lightning
07/29/02	NPCC	Reliant Resources and Consolidated Edison Company of New York, Inc.	INT	N/A	9,000	Equipment failure
07/30/02	NPCC	New York Independent System Operator	PA	N/A	N/A	Weather – heat and high demand
07/31/02	WECC	B.C. Hydro & Power Authority	INT	240	50,000	Human error
08/01/02	ECAR	Consumers Energy Company	INT	100	114,500	Weather – severe storms
08/02/02	NPCC	Hydro-Québec – TransÉnergie	INT	848	N/A	Weather – lightning
08/02/02	WECC	WECC Contractor Accident	INT	1,071	350,000	Contractor accident
08/09/02	FRCC	Lake Worth Utilities	INT	51	25,000	Animal contact
08/14/02	NPCC	Hydro-Québec – TransÉnergie	INT	1,060	8	Weather – lightning

System Disturbances — 2002

Date	Region	Utilities	Type*	MW	Customers	Cause
						suspected
08/26/02	WECC	Tucson Electric Power Company	INT	270	50,000	Equipment failure
08/28/02	FRCC	Lake Worth Utilities	INT	67.6	25,000	Weather – lightning
09/03/02	WECC	California Independent System Operator	UO	0	0	Wild fires
09/08/02	NPCC	Hydro-Québec – TransÉnergie	UO	1,060	N/A	Weather – lightning
09/09/02	NPCC	Independent Electricity Market Operator	VR	400	N/A	Weather – hot and humid
09/15/02	MAPP	Minnesota Power Inc.	UO	0	0	Equipment malfunction
09/26/02	WECC	Western Interconnection – northwest area	UO	0	0	Unknown
10/01/02	NPCC	ISO New England	UO	0	0	Fire, cause unknown
10/03/02	SERC	Entergy Corporation	INT	N/A	242,910	Weather – Hurricane Lili
10/03/02	SPP	CLECO Power, L.L.C	INT	N/A	164,500	Weather – Hurricane Lili
10/03/02	SPP	Lafayette Utilities	INT	212	55,000	Weather – Hurricane Lili
10/08/02	WECC	Bonneville Power Administration	UO	N/A	N/A	Suspected human error, equipment failure
10/21/02	MAPP	Manitoba Hydro	UO	0	0	Equipment failure
10/31/02	NPCC	Hydro-Québec – TransÉnergie	UO	0	0	Equipment failure
11/6/02	WECC	California Independent System Operator	INT	0	877,000	Weather – heavy rain, wind
11/07/02	NPCC	Hydro-Québec – TransÉnergie	INT	250	1	Weather – snow, high winds
11/22/02	NPCC	Hydro-Québec – TransÉnergie	UO	0	0	Equipment failure, relay malfunction
12/3/02	SERC	Entergy Corporation	INT	0	43,000	Weather – ice storm
12/04/02	SERC	Duke Energy Corporation	INT	7,200	1,140,000	Weather – severe winter storms, ice, snow
12/05/02	SERC	Carolina Power & Light Company	INT	2,400	464,000	Weather – severe winter storms, ice, snow
12/11/02	SERC	Dominion – Virginia Power Company	INT	63	90,000	Weather – freezing rains
12/14/02	WECC	Pacific Gas & Electric Company	INT	0	2,100,000	Weather – heaving rain, winds
12/19/02	WECC	Pacific Gas & Electric Company	INT	0	385,000	Weather – heaving rain, winds
12/25/02	MAAC	Metropolitan Edison Company	INT	0	95,630	Weather – heavy snow
12/25/02	MAAC	PPL Electric Utilities	INT	0	166,000	Weather – heavy snow
12/26/02	WECC	WECC Severe Weather - Ice	INT	950	N/A	Weather – severe storm, ice

*INT = Customer Interruptions, UO = Unusual Occurrences, DR = Demand Reduction, VR = Voltage Reduction, PA = Public Appeal
N/A = Not Available

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