1996

System

Disturbances

Review of Selected 1996 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 1996 bulk electric system disturbances, unusual occurrences, and demand reductions.

NERC has published its findings on bulk electric system disturbances, demand reductions, and unusual occurrences 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 Policies to their planning.
- Determining if these Policies 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.

CONTENTS

INTRODUCTION

The U.S. Department of Energy (DOE) has established requirements for reporting major electric utility system emergencies (**Appendix A**). These emergencies include electric service interruptions, voltage reductions, acts of sabotage, “unusual occurrences” that can affect the reliability of the bulk electric systems, and fuel supply problems. When a utility experiences an electric system emergency that it must report to DOE, the utility sends a copy of the report to its Regional Council, which then sends a copy to NERC. Canadian utilities often voluntarily file emergency reports with DOE and NERC as well.

NERC’s annual review of system disturbances begins in November when the Disturbance Analysis Working Group meets to discuss each disturbance reported to NERC so far that year. The Group then contacts the Regional Council or utility(ies) involved and requests a detailed report of each incident. The Group summarizes the report for this review and analyzes it using the NERC Operating Policies and Planning Policies 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 1996, utilities reported 29 incidents of system disturbances, demand reductions, voltage reductions, public appeals, or unusual occurrences, seven more than were reported in 1995. These incidents are listed chronologically in **Appendix C** and categorized as:

- Sixteen system interruptions
- Four unusual occurrences
- One demand reduction
- Two voltage reductions and public appeals
- Two voltage reductions and demand reductions
- Four voltage reductions

This document contains analyses of seven incidents. 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

Communications

The lifeblood of bulk electric systems operations is communications. It is a necessity for the operational security of the Interconnections and their basic key components ? the control areas ? operating across North America. Under normal conditions, people and organizations within a control area must communicate among themselves as well as with those in adjacent control areas to keep each other apprised of the current operational situation, planned actions, and potential problems. During an emergency as well as prior to system restoration, communications between control areas are a necessity. The failure in one case to recognize the criticality of several line outages and widely communicate this information to other utilities precluded those utilities from evaluating the impact of the outages and making system adjustments had they perceived a need to take action.

References:

- Peninsular Florida Disturbance ? March 12, 1996
- Western Interconnection (WSCC) System Disturbances ? July 2-3, 1996
- Big Rivers Electric Corporation Disturbance ? August 7, 1996
- Western Interconnection (WSCC) System Disturbance ? August 10, 1996
- Allegheny Power System Disturbance ? September 21, 1996

Planning

Bulk electric systems are not created in a vacuum. System planners and operators work together during the design of new facilities and the modification of existing facilities. In addition, planners and operators must be attuned to changes in flows and loadings on transmission lines, transformers, and other elements that may require adjustments to maintain system coordination, generation loadings, proper operating procedures, the need for reconfiguration of facilities, etc. Such system changes and analyses of system disturbances are the inputs for selecting the operating scenarios to be studied. In one case, it took a system disturbance to point to the need for stronger ties to neighboring systems.

References:

- Peninsular Florida Disturbance ? March 12, 1996
- Southwestern Public Service Company System Disturbance ? April 16, 1996
- Western Interconnection (WSCC) System Disturbances ? July 2-3, 1996
- Big Rivers Electric Corporation Disturbance ? August 7, 1996
- Western Interconnection (WSCC) System Disturbance ? August 10, 1996
- New York Power Pool Disturbances ? August 26 and October 30, 1996

System Protection

The system operator is essential to the steady-state security of the transmission system, but it is the automatic system protection schemes that make the millisecond decisions to isolate faulted equipment and maintain voltage and frequency based on logic provided by system planers and operators. If these protection schemes are not maintained adequately or the logic reviewed periodically to address changes in facilities or transmission system flows, they will not perform the job they are expected to do. In one case, system protection removed both utility and non-utility generation when it should not have.

References:

- Peninsular Florida Disturbance ? March 12, 1996
- Southwestern Public Service Company System Disturbance ? April 16, 1996
- Western Interconnection (WSCC) System Disturbances ? July 2-3, 1996
- Western Interconnection (WSCC) System Disturbance ? August 10, 1996

Training

The bulk electric systems of North America comprise the largest machine devised by man. System operators are expected to be able to understand, act on, and control this machine based on the information presented to them in various visual and auditory forms by supervisory control and data acquisition systems. The only way they can do this is by being trained and retrained on a regular basis to reinforce and add to their knowledge as systems and facilities change. The need for training is implied in all the disturbances reviewed in this report, and clearly delineated in three.

References:

- Big Rivers Electric Corporation Disturbance ? August 7, 1996
- Western Interconnection (WSCC) System Disturbance ? August 10, 1996
- Allegheny Power System Disturbance ? September 21, 1996

Automatic Load Shedding

A basic responsibility of the control area is to balance generation and demand. When demand rises and additional generation is not available internally and cannot be obtained externally, frequency falls below the prescribed 60 Hz of the Interconnection, unless load is shed by the control area or utility. It is incumbent on utilities, the control areas, and the regional reliability councils to develop adequate load shedding programs, coordinate these plans to meet their needs, and update and test them regularly. In several cases, although load shedding plans were available, they were inadequate or did not work as planned.

References:

- Peninsular Florida Disturbance ? March 12, 1996
- Southwestern Public Service Company System Disturbance ? April 16, 1996
- Western Interconnection (WSCC) System Disturbances ? July 2-3, 1996
- Western Interconnection (WSCC) System Disturbance ? August 10, 1996

DISTURBANCES BY ANALYSIS CATEGORY — OPERATING POLICIES

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

1. Peninsular Florida Disturbance ? March 12, 1996
2. Southwestern Public Service Company System Disturbance ? April 16, 1996
3. Western Interconnection (WSCC) System Disturbances ? July 2–3, 1996
4. Big Rivers Electric Corporation Disturbance ? August 7, 1996
5. Western Interconnection (WSCC) System Disturbance ? August 10, 1996
6. New York Power Pool Disturbances ? August 26 and October 30, 1996
7. Allegheny Power System Disturbance ? September 21, 1996

DISTURBANCES BY ANALYSIS CATEGORY — PLANNING POLICIES

Policies, Procedures, and Principles and Guides for Planning Reliable Bulk Electric Systems	Incident Number						
	1	2	3	4	5	6	7
I. Forecast							
II. Resources							
A. — General		v			v	v	v
B. — Demand-side Resources		v	v				
C. — Supply-Side Resources						v	
III. Transmission							
A. — Adequacy	v	v	v	v	v	v	v
B. — Security	v		v		v	v	v
C. — Coordination			v	v	v	v	v
D. — Protection Systems	v	v	v	v	v		v

1. Peninsular Florida Disturbance ? March 12, 1996
2. Southwestern Public Service Company System Disturbance ? April 16, 1996
3. Western Interconnection (WSCC) System Disturbances ? July 2–3, 1996
4. Big Rivers Electric Corporation Disturbance ? August 7, 1996
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PENINSULA FLORIDA DISTURBANCE — MARCH 12, 1996

Transmission problems occurred in peninsula Florida on March 12, 1996 that created an electrical island in west Florida and portions of central Florida, resulting in the loss of about 3,440 MW of demand. The separation was a result of several conditions: planned and forced outages, unseasonably cool temperatures, and higher than normal electricity transfers from north and northeast Florida into the west and west central Florida resulting in overloads on the 115 kV and 230 kV lines.

Discussion

Florida has one major north to west-central 230 kV transmission corridor, the Silver Springs – Silver Springs North (SVS-SVSN) corridor which consists of two 230 kV lines. The central region of the state has three major east to west 230 kV transmission lines: 1. the Sanford – North Longwood line, 2. the Poinsett – Holopaw line, and 3. the Cape Canaveral to Indian River to Stanton (Indian River to Stanton consist of two 230 kV lines in parallel) to Rio Pinar lines. The SVS-SVSN and the central east – west 230 kV ties serve to electrically connect northeast and east Florida to central and west central Florida. Southern Florida has three major southeast to southwest transmission lines: 1. the 500 kV Andytown – Orange River line, 2. the 230 kV Corbett – Orange River line, and 3. the 138 kV Ranch – Ft. Meyers line. Figure 1 shows a schematic of the configuration of these lines.

On March 12, 1996, a review of the statewide capacity reserve indicated no problem for this day because 4,793 MW of capacity reserves within peninsula Florida were available. At the time of the disturbance, west Florida had over 1,585 MW of generation on planned maintenance and 1,677 MW on forced outage or restricted output, resulting in 3,262 MW of generation unavailable in the western region.

Electricity scheduled from Southern Company's (SCS) control area into the state for hour ending 0700 was about 3,400 MW. The majority of this electricity comes into Florida over the two 500 KV lines that tie SCS's system to FPL's Duval substation in the northeast corner of the state. In addition to this resource, a number of generating facilities are located in northeast and east Florida connecting to the 230 kV transmission grid — Putnam plant (550 MW), Seminole plant (1,270 MW), Cape Canaveral plant (810 MW), Sanford plant (950 MW), and Indian River plant (800 MW).

Due to the planned and forced outages in west Florida that day and unseasonably cool temperatures, electricity transfers from north and northeast Florida into west and west central Florida were higher than normal and resulted in overloads on portions of central Florida's 230 kV and 115 kV transmission system. Further aggravating the situation was the outage of one of the 230 kV Indian River – Stanton lines that was out of service on an extended forced outage, creating a "weak link" in one of the three 230 kV east-west ties (Cape Canaveral – Indian River-Stanton – Rio Pinar).

As the demand in Florida began to increase in the very early morning hours of March 12, the remaining line in the double circuit pair from Indian River to Stanton began to load above rated limits. To reduce the loading on this line, the Orlando Utilities Commission's (OUC) dispatcher opened the Stanton end of the 230 kV Stanton – Rio Pinar line. Opening this line, interrupts electricity flowing from the Cape Canaveral and the Indian River plants to the Rio Pinar/North Longwood area (see illustration), reducing the electricity flow on the remaining 230 kV Indian River – Stanton line. With the Stanton – Rio Pinar line out of service, the remaining lines into the Rio Pinar/North Longwood area began to load more heavily. By 0500 hours, a second east-west 230 kV tie, the Sanford to North Longwood line, was beginning to overload.

Florida Power Corporation (FPC) started peaking units that morning at its Debary plant, located northwest of this corridor, to back off the flow on the 230 kV Sanford – North Longwood line, and Florida Power & Light

(FPL) sectionalized its Sanford bus. Both of these strategies successfully reduced the loading on this corridor, but resulted in additional loading on the remaining 230 kV Indian River – Stanton line, pushing the load on this line above rated limits.

To address the increased loading on the 230 kV Indian River to Stanton line, OUC split its Indian River 230 kV bus, separating OUC's system from Cape Canaveral and electrically tying the Indian River unit No.3 to the Cape Canaveral bus. Indian River unit No.3 was generating 302 MW at the time. This action had an immediate and severe impact on the remaining East-West transmission ties, resulting in these lines loading above rated limits.

To reduce the loading on the 230 kV Sanford – North Longwood line, FPC opened the North 230 kV Longwood – Myrtle Lake line. FPC then sectionalized the Silver Springs bus to reduce the loading on the SVS – SVSN corridor. These two switching operations addressed the overloads on FPC's system.

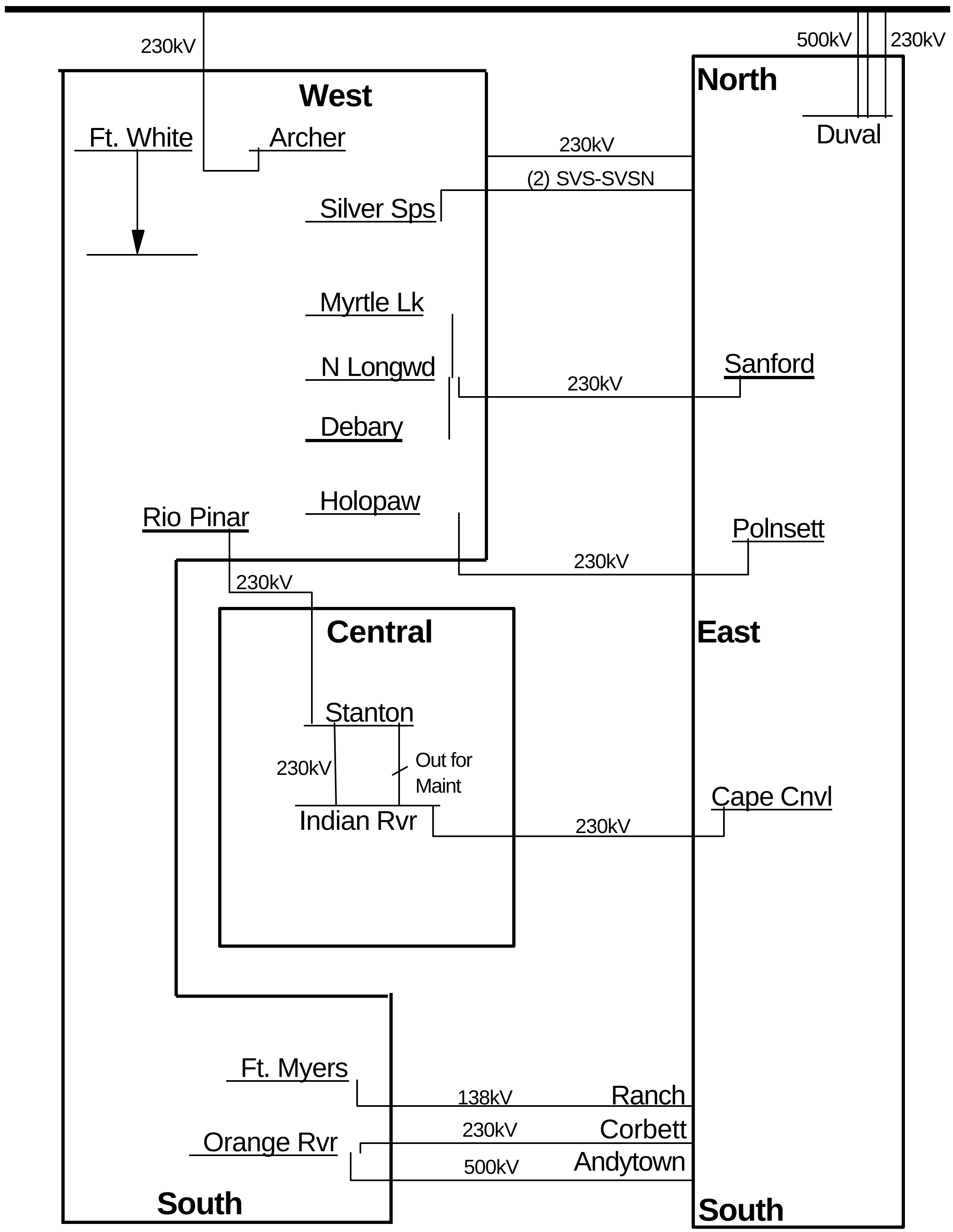
Following the Silver Springs bus split, the 230 kV Poinsett – Holopaw line immediately loaded to about 150% of its rated value, faulted, and system protection removed it from service. The loss of the Poinsett – Holopaw line caused the Sanford – North Longwood line to load to about 120% of its rated value. Some economy sales negatively impacting the flow on this line were cut in an attempt to lower the loading on the line. This action had a positive impact as the flows began to decrease, but was not sufficient to prevent the line from faulting. As a result of the other previous events and the Sanford – North Longwood line opening, an additional series of line overloads occurred and these lines were removed from service.

At this point, the 230 kV east-west transmission system in central Florida was so fragmented that electricity was forced across Florida's southeast-southwest transmission corridor, and in a northerly direction over the 230 kV transmission system. The magnitude of the electricity attempting to flow over these lines to load centers in west and central Florida resulted in line loadings above emergency ratings. These overloads also resulted in a number of lines overloading and opening by zone relay operation. These series of events left much of west and central Florida connected to the Florida network through one 230 kV northern tie. This line, the Ft. White – Archer line, finally opened due to an out of step condition.

The series of events described above left west Florida and portions of central Florida as an island with about 12,588 MW of demand and 9,932 MW of generation. The Debary Plant (507 MW), which was included in the island, was removed from service due to low voltage and nine cogenerators were removed from service due to under frequency. The loss of this generation further reduced the island's generation to 9,148 MW. This generation deficiency reduced the island's frequency to about 58.65 Hz, and under frequency relays within the island operated decrease demand. A total of 3,440 MW was shed, about 27% of the total demand in the island.

As a result of the under frequency operations, system frequency within the island was restored to 59.7 Hz in six seconds. Synchronizing relays at the Ft. White substation reclosed within 90 seconds and the island was tied back to the rest of Florida's interconnected system. System operators within Florida responded to the disturbance by starting available combustion turbines, implementing load management, and piecing the transmission network back together.

Figure 1 — Schematic Diagram for Peninsula Florida Disturbance



Conclusions

1. Florida's under frequency program operated adequately to prevent a black out in the islanded area; however, several issues will require additional study: the level of under frequency and the recovery time of the frequency. Also, individual utility reports indicate that there were some under frequency relays that did not operate, and other relays that operated but failed to open feeder breakers.

2. Actions should have been taken to reduce the electricity flowing from northeast and east Florida to demand centers in central and west Florida. One course of action would have been to further reduce interchange transactions that were negatively impacting these overloaded lines and to implement load reduction measures in central and west central Florida.

3. Several switching operations were implemented to solve loading problems within a utilities' own system that resulted in heavier loading on the surrounding 230 kV transmission network.

4. Nine cogenerators within the island were removed from service due to under frequency relay actions as a result of the disturbance. This action resulted in 277 MW less generation within the island, compounding the problem.

5. The units at the Debary plant should not have been removed from service.

6. The agreed to operating procedures to control the line loadings on some of the lines were less effective than normal due to other switching operations in the state, which resulted in an abnormal transmission configuration in this area. Also, had real-time information been available from all major Florida utilities, system dispatchers would probably have been aware of the actual system configuration

7. Because of planned system improvements in the OUC system including additional generation and transmission facilities coupled with the second 230 kV Indian River – Stanton line back in-service, the probability of the Indian River – Stanton corridor overloading in the future is very low.

Recommendations and Noted Corrective Action

Appropriate actions should be initiated to ensure that the issues related to the under frequency program are addressed including an evaluation of the islanded area's frequency decay and recovery curve shape.

Refer to: NERC Operating Policy 6 — Operations Planning, C. Automatic Load Shedding
NERC Operating Policy 4 — System Coordination, D. System Protection Coordination
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, D. Protection Systems

Note: The system's response to this event was reviewed, and the conclusion was that the Florida Electric Power Coordinating Group's under frequency load shedding schedule is adequate for this type of disturbance. Evaluation of the frequency decay and recovery curve shape was made and simulations showing the frequency dip close to actual and frequency recovery slightly faster than actual.

Several switching operations were implemented to solve loading problems within a utility's own system that resulted in heavier loading on the surrounding 230 kV transmission network.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy

Note: The Transmission Reliability Coordinator's role was reviewed and changed appropriately to provide additional status of transmission lines, breakers, and generation along with additional authority coordinate transmission outages and cancel schedules.

Host utilities with interconnection agreements with independent power producers (IPPs) and cogenerators should review with those entities their protection schemes, and coordinate these schemes within the Florida transmission network. In many cases, IPPs and cogenerators are firm resources to the purchasing utility and the NERC Policy 6.C. (Automatic Load Shedding) requires that "Load Shedding plans shall be coordinated among interconnected systems."

Refer to: NERC Operating Policy 6 — Operations Planning, C. Automatic Load Shedding
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, D. Protection Systems

Note: All host utilities have reviewed the protection schemes of IPPs and cogenerators that are firm resources to a purchasing utility.

The removal from service of the combustion turbine units should be reviewed and modifications to relaying settings implemented, as necessary.

Refer to: NERC Operating Policy 4 — System Coordination, D. System Protection Coordination
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, D. Protection Systems

Note: The removal from service of the combustion turbine units at the Debary plant was reviewed. All Debary combustion turbines on line during the disturbance were appropriately removed from service, but the two Debary combustion turbines that stayed on line should have been removed from service due to low voltage.

Interconnected utilities should perform additional coordinated operational studies to determine the impact of planned and forced generation and transmission outages on the bulk transmission network.

Refer to: NERC Operating Policy 6 — Operations Planning, B. Emergency Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, B. Security

Note: Although the role of the Transmission Reliability Coordinator was to perform contingency studies on the existing transmission system, the additional duty of performing contingency studies on the planned transmission system for the next day was added. The operations Planning Coordinator performs contingency studies on the planned transmission system for days two through seven and holds conference calls with transmission providers to review results of the contingency studies.

For additional information on this event, please contact the Florida Reliability Coordinating Council (FRCC) office.

SOUTHWESTERN PUBLIC SERVICE COMPANY SYSTEM DISTURBANCE — APRIL 16, 1996

Pre-disturbance Conditions

Many generating station substation insulators on the Southwestern Public Service Company (SPS) system were contaminated due to a combination of factors. Due to drought conditions, the area had an unusually high amount of dust and soot from prairie fires during the spring. This condition, coupled with cooling tower spray and coal dust at the coal-fired plants, increased the possibility of flashovers (arcs).

SPS had an outage of both units at Jones Station near Lubbock on March 27, 1996. Foggy conditions mixed with the insulator contamination caused a bushing on a 230 kV bus tie breaker to flashover, opening both the No.1 and No.2 bus differentials. To mitigate this condition, SPS began an inspection of all generating station substations to determine if this contamination might affect other plants.

Inspection of the Tolk plant bus showed contamination was present and plans were made to wash the insulators using a high-pressure demineralized water washer. This procedure is a standard utility practice for washing contamination from energized equipment and was done routinely on the SPS system. On April 16, 1996, this washing procedure was being used. Proper hot-bus clearances were established. The weather conditions were fair with a temperature of 60 deg F., wind at 15 mph from the southwest, and relative humidity at 30%.

Major facilities not in service on the transmission system at that time were the 230 kV Yoakum County – AMOCO switching station line, the 115 kV Tuco – Hale County Interchange line, the 230 kV breaker at the Bushland Interchange end of the 230 kV Bushland Interchange – Harrington line, the 230/138 kV, 150 MVA auto-transformer at Midland Interchange, and the 230/115 kV, 225 MVA auto-transformer at Lubbock South Interchange.

The SPS system demand was 2,775 MW. The scheduled interchange with the Southwest Power Pool to the east was zero. Actual flows were 62 MW into Tuco from Public Service Company of Oklahoma's (PSO) Oklaunion substation, 48 MW from Nichols to PSO's Elk City substation, and 9 MW from West Texas Utilities Company's (WTU) Shamrock substation. The Texas County to West Plains Energy's Liberal substation tie was open at the time. SPS was importing 160 MW through the Blackwater HVDC tie and exporting 120 MW through the Eddy County HVDC tie to El Paso Electric Company and Texas - New Mexico Power Company at the time. In addition, SPS was supplying 65 MW to Lubbock (City) Power & Light Department, 8 MW to the City of Brownfield, 4 MW to the City of Tulia, and 2 MW to the City of Floydada.

Total system generation capability on line was 3,339 MW. Total system net generation (from 13 units) just before the disturbance was 2,789 MW. Included in this amount was 35 MW SPS was purchasing from two industrial customers.

A total of 740 MW of generation capability was not in service due to maintenance and 218 MW of generation was in either hot or cold reserve.

Disturbance

During the washing of 230 kV breaker TK47 at Tolk, on the Roosevelt County No.2 line, the mist from the washing operation caused an adjacent bushing to arc to ground resulting in a differential relay trip of the 230 kV No.2 bus. Circuit breakers TK25, TK29, TK32, TK35, TK47, TK55 opened to clear a single "C" phase-to-ground fault on TK47 (See Figure 1, Tolk oneline). These breaker openings removed from service the Tolk unit No.2 at 10:20:32 EDT leaving the control area 537 MW deficient. The fault was cleared in 5 cycles.

A 230 kV bus backup relay (zone 3) at Plant X saw the fault and operated. This relay operates through a timer, which was set at 1.2 seconds. This backup timer was wired through the ICS target relay and did not drop out after the fault was cleared. 1.27 seconds after the initial fault, all breakers on the 230 kV bus at Plant X opened due to this relay mis-operation. This mis-operation removed Plant X unit No.4 and two major ties to the north end of the system (See Figure 2, Plant X oneline).

The SPS system stayed together for about 2.5 minutes. During this time Tolk unit No.1 had major problems due to the initial voltage dip:

a.) East forced draft fan variable frequency drive was removed from service and started a boiler runback
b.) Static inverters on the variable frequency drives transfer to battery
c.) Tolk sent runback signal to Eddy County HVDC
d.) Generator under frequency alarm sounded (59.5Hz)
e.) The submerged slag conveyor was removed from service
f.) Soot blower north air compressor was removed from service
g.) Main power auxiliaries alarm sounded
h.) Air preheater west was removed from service
i.) Coal feeders “B” through “F” ran back momentarily and the furnace safeguard supervisory system (FSSS) put gas in the boiler

Tolk unit No.1 turbine ran back for about 29 seconds before the boiler was removed from service resulting in the loss of about 100 MW. At 10:21:12.8 EDT the west forced draft fan was removed from service setting off the following sequence:

a.) The FSSS removed the boiler from service due to loss of both forced draft fans
b.) The turbine shifted to “follow mode” - closing valves to hold pressure
c.) Removal from service of about 300 MWs of generation during the next minute and 51 seconds

During this time, the flow on the ties to the Southwest Power Pool was increasing and voltages across the system were decreasing. Just before the ties to the Southwest Power Pool opened, SPS was importing about 765 MWs.

The 345 kV Tuco –Oklaunion tie was opened by system protection at 10:23:04.91 at the Oklaunion end. At 10:23:05.82 the 230 kV Tuco – Swisher County line was removed from service. This line was the last north-south 230 kV tie. About 9 cycles later the 230 kV Nichols – Elk City tie to PSO opened on out-of-step. At 10:23:06.62 the 115 kV Nichols – Shamrock tie to WTU opened at Shamrock leaving SPS separated from the Southwest Power Pool. The Tuco bus voltage was 197 kV just before separation and 214 kV immediately after.

After separation from the Pool, frequency dropped very rapidly. All three steps of under frequency relays operated throughout the SPS system shedding about 700 MW of demand. The remaining 115 kV ties opened south of the Plant X 115 kV bus leaving the Plant X unit No.2 and 126 MW of demand tied to the north end of the system. The frequency on the north end went high and the south end continued to decay.

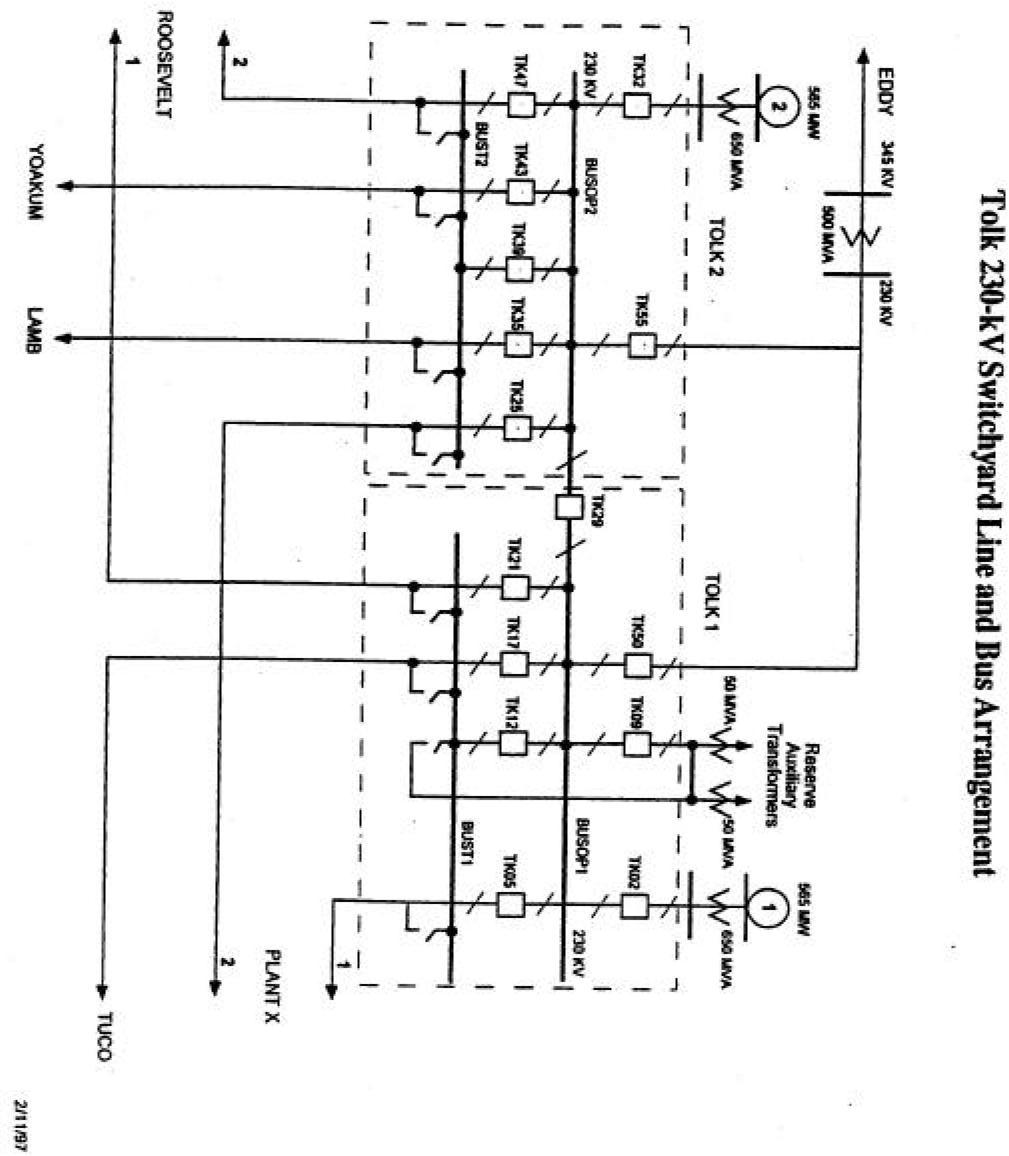

Tolk 230-kV Switchyard Line and Bus Arrangement
EDDY
345 KV
500 MVA
230 KV
565 MW
650 MVA
TOLK 2
TOLK 1
TK32
TK47
230 KV
BUSOP2
BUST2
TK43
TK39
TK55
TK35
TK25
TK29
TK21
TK50
TK17
TK09
TK12
50 MVA
Reserve
Auxiliary
Transformers
50 MVA
BUSOP1
BUST1
TK02
TK05
565 MW
650 MVA
230 KV
ROOSEVELT
YOAKUM
LAMB
PLANT X
TUCO
1
2
1
2
2/11/97

Figure 1

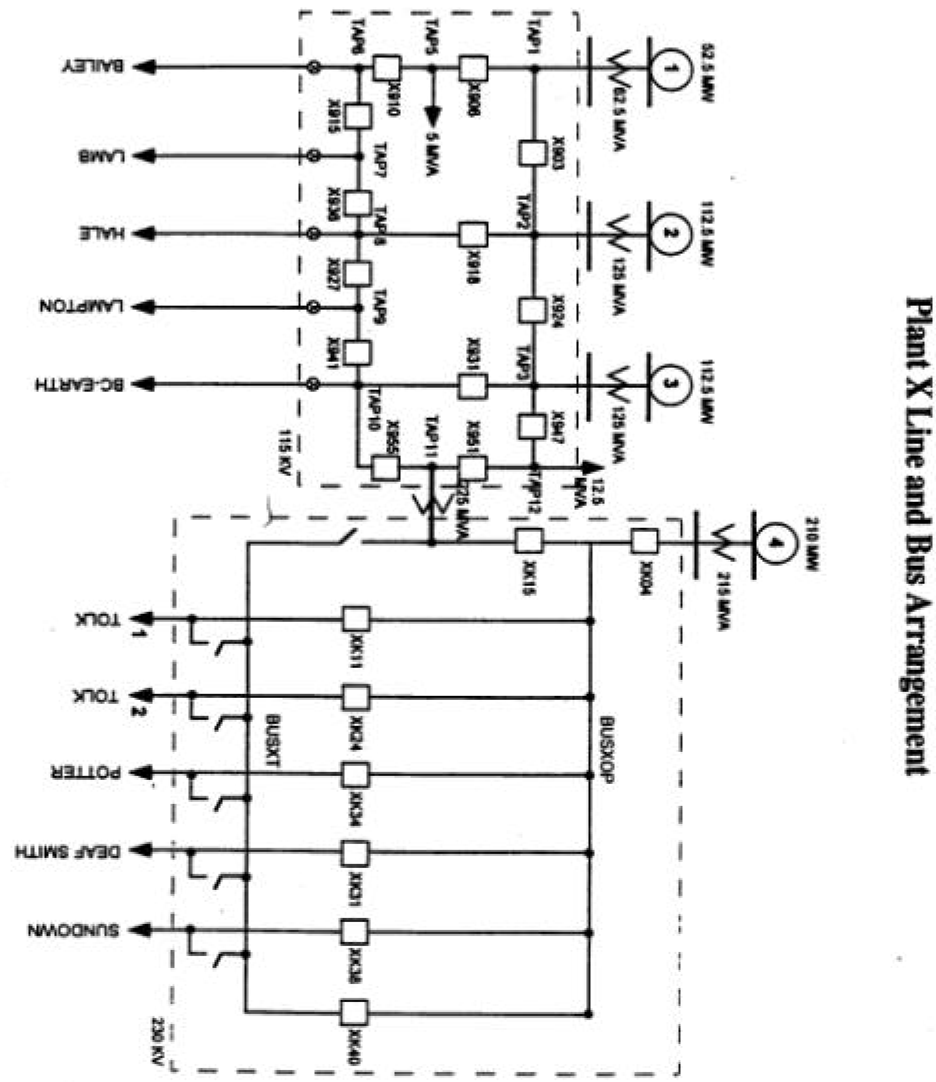

Plant X Line and Bus Arrangement
BAILEY
LAMB
HALE
LAMPTON
BC-EARTH
TOLK 1
TOLK 2
POTTER
DEAF SMITH
SUNDOWN
BUSXT
BUSXOP
115 KV
230 KV
52.5 MW
112.5 MW
112.5 MW
210 MW

Figure 2

System Status after Upset Stabilized (10:30 AM, EDT)

Four units remained online: the Harrington unit No.3 carrying 345 MW, the Nichols unit No.1 (23 MW), the Nichols unit No.3 (254 MW), and the Plant X unit No.2 (59 MW). The system demand was 681 MW (Panhandle Division – 555 MW, Southern Division – 126 MW, and New Mexico Division – 0 MW).

The approximate amount of load shed by under frequency relays was 701 MW. The removal from service of the Eddy County HVDC resulted in a gain of 120 MW to the SPS system, and the removal from service of the Blackwater HVDC resulted in a reduction of 161 MW.

Restoration

Restoration began after assessing the status of the power plants and the area control centers. The system operators had a good "picture" of the transmission system via the energy management system/supervisory control and data acquisition (EMS/SCADA) system. Only two remote terminal units (RTUs) failed during the disturbance. The south end of the system did not have a source of generation except for a pocket of demand around the Plant X 115 kV bus. This demand was served by Plant X unit No.2 and the single 115 kV tie to the north through Castro County Interchange.

Area control centers began dispatching personnel to all major interchanges and substations. Under frequency lockout relays were logged and reset by the SCADA system. Reclosers were turned "off." The process of logging and resetting relay targets was begun.

The first objective was to re-establish the 230 kV Nichols – Elk City tie and synchronize with the Southwest Power Pool. The line was energized from Nichols and synchronized at 10:48:09 AM. Maddox Station was asked to initiate "black start" procedures.

The next step was to get station electricity back to the plant buses and re-establish the north/south 230 kV ties. After verifying that all 230 kV breakers on the Plant X bus were open, the 230 kV Potter County – Plant X line was closed at 11:01 AM. The Plant X 230 kV bus voltage was 239.46 kV. The 230 kV and the 115 kV buses were tied back together by closing breaker XK15 (See Figure 2), the high-side breaker on the 225 MVA 230/115 kV auto-transformer, at 11:12. The 230 kV bus voltage was 246.8 kV and flow through the auto-transformer was 56 MVA. To get station electricity to Tolk unit No.1, the Plant X to Tolk No.1 line was closed at 11:19. The line picked up 172 MW and the Plant X 230 kV bus voltage dropped to 173.2 kV. Failure to open TK50, one of the 345/230 kV auto-transformer low-side breakers, allowed the 345 kV line to Eddy County Interchange to be energized (See Figure 1). This picked up something in excess of 220 MVA. Breaker TK50 at Tolk was opened at 11:20 and the Plant X 230 kV bus voltage came back up to 260.2 kV.

From this point, transmission interchanges and substations were energized and service was restored as generation or purchase power became available. By 6:00 p.m., essentially all customer service had been restored.

Conclusions

Several problem areas were identified as a result of the April 16th event. These problems included protection, prevention, and restoration.

The main protection problem was the mis-operation of the 230 kV bus backup relay at Plant X. This backup relay was set to "see" the end of the longest line from Plant X (set for 105 miles). Tolk Station is 10 miles from Plant X. The 230 kV bus backup relay at Plant X saw the fault at Tolk Station and activated the timer. This timer did not de-energize after the fault at Tolk Station was cleared. The timer did not de-energize because the ICS target unit was set on the 0.2 amp tap and was in series with the timer, which energized at about 180 ma. This 180 ma pickup was enough to keep the ICS unit on the 0.2 amp tap. The contacts on the ICS unit were wired in the timer and held it locked in until it timed out and opened the Plant X 230 kV bus 1.2 seconds later.

The prevention area identified includes keeping all generation units on-line and not letting demand exceed generation. Under heavy demand conditions, the total gross generation at Tolk Station is about 1,100 MW, and the total gross generation at the Harrington Station is about 1,080 MW. These are the largest plants on the SPS system. Due to SPS's limited import capability, a plan to react to system protection removing from service an entire plant was needed. The best method to achieve this while satisfying most all contingencies would be to add additional automatic load shedding capabilities.

Providing more isolation between units and the unit buses at major plants also minimizes the possibility of loosing an entire plant.

One of the main problems that occurred during the restoration process was extremely high voltages on the 230 kV transmission system. Procedures need to be developed to minimize the voltage rise during restoration. Procedures for energizing de-energized buses must be defined. Service points that can affect plant station electricity and fuel supply needed to be identified, along with communication facilities that may have no or a questionable source of backup electricity.

Recommendations

1.) Correct control circuit problem at Plant X

Revise the backup control circuit scheme to prevent the ICS unit from carrying any current until the timer has timed out. This change was made.

Refer to: NERC Operating Policy 4. — System Coordination, D. System Protection Coordination
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy

2.) Add additional automatic load shedding

SPS has three steps of under frequency relays that operate at 59.3 Hz, 59.0 Hz, and 58.7 Hz and shed about 10% of the demand in each step. On April 16, about 700 MW were shed by these relays. This amount was not enough to cover the loss of 1,000+ MW (two Tolk units). A fourth step of under frequency relays set at 58.4 Hz, removing an additional 10% to 15%, should be installed. This work was completed by June 1997.

About 150 MW of interruptible large industrial load was contracted to be interrupted via the EMS and a radio controlled paging system during emergencies. With minimal programming in the EMS it will be possible to monitor the area control error (ACE) and issue a command to shed these interruptible demands when the ACE exceeded a set value, i.e. 400 MW. In many instances, this should prevent separation from the Southwest Power Pool and under frequency operation.

Refer to: NERC Operating Policy 5 — Emergency Operations, D. Separation from the Interconnection
NERC Operating Policy 6 — Operations Planning, C. Automatic Load Shedding NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, II. Resources, Guides, B. Demand-Side Resources

3.) Implement high voltage limiting procedures and devices

Refer to: NERC Operating Policy 4 — System Coordination, A. Monitoring System Conditions
NERC Operating Policy 5 — Emergency Operations, E. System Restoration

a.) Minimize high-voltage problems by energizing interchanges at the same time the bus is energized.

b.) Remove all transmission capacitors before energizing the bus.

c.) Check transformer tap changer positions before energizing. During system collapse and voltage decay all tap changers with automatic controls will have run to the maximum or full boost position, these should be lowered.

d.) Selectively energize known reactive demands to help control voltage.

In addition, 230 kV line reactors should be added on 345 kV lines at the Tuco Interchange, Tolk Station, and Eddy County Interchange to facilitate energizing during high-voltage situations.

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

4.) Operational steps during restoration

In addition to controlling high-voltage conditions on the system during restoration, the operators also must reasonably match demands and generation.

a.) Open or "green flag" breaker control switches and turn off reclosers. These actions will prevent automatic line-bus condition reclosing of adjacent lines when the bus is energized.

b.) Energize demands that are on the under frequency load shedding steps to provide some measure of protection if demand exceeds available capacity.

c.) Identify gas company compressor stations and processing plants that can affect gas supply to generating stations and work towards restoring their service.

d.) Identify communication facilities that may have no or a questionable back up source of electricity.

Refer to: NERC Operating Policy 6 — Operations Planning, C. Automatic Load Shedding
NERC Operating Policy 6 — Operations Planning, D. System Restoration
NERC Operating Policy 7 — Telecommunications, A. Facilities
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, II. Resources, Guides, B. Demand-Side Resources
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, D. Protection Systems

5.) Provide more isolation between adjacent units

Investigate bus arrangements that would eliminate single contingencies that could trip both Tolk units, such as:

a.) Removing the existing 230 kV bus tie breaker TK29. This action would eliminate the single point of failure that would operate both Tolk unit No.1 and Tolk unit No.2 bus differentials. The 230 kV bus tie connection would be maintained through TK50 and TK55. This change was completed early in 1997.

b.) Converting the Tolk Buses to a breaker and a half scheme would eliminate any common point of failure and minimize exposure to differential relay operations.

c.) Establish a 345 kV bus at Tolk Station and move unit No.2 to this bus to provide additional isolation as well as a spare unit transformer for both Tolk units.

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

6.) Strengthen ties with the Southwest Power Pool

Investigate an additional 345 kV ac tie to a strong 345 kV bus in Kansas or Oklahoma to allow SPS to survive a disturbance of the magnitude that occurred on April 16, 1996. The 345 kV Potter – Holcomb line was energized in the fall of 2001.

Refer to: NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy

For more information on this event, please contact the Southwest Power Pool (SPP) office.

WESTERN INTERCONNECTION (WSCC) SYSTEM DISTURBANCES — July 2 & 3, 1996

Detailed Description

A disturbance occurred at 1424:37 MDT on July 2, 1996 that ultimately resulted in the Western Systems Coordinating Council (WSCC) system separating into five islands (Figure 1) and in electric service interruptions to over two million customers. Electric service was restored to most customers within 30 minutes, except on the Idaho Power Company (IPC) system, a portion of the Public Service Company of Colorado (PSC), and the Platte River Power Authority (PRPA) systems in Colorado, where some customers were out of service for up to six hours. On portions of the Sierra Pacific Power Company (SPP) system in northern Nevada, service restoration required up to three hours.

The first significant event was a single phase-to-ground fault at 1424:37.18 MDT on the 345 kV Jim Bridger – Kinport line (Figures 1 & 2). The fault occurred 97 miles east of Kinport and was caused by a flashover (arc) when the conductor sagged close to a tree. System protection removed the line from service clearing the fault in three cycles.

System protection opened the 345 kV Jim Bridger – Goshen line twenty milliseconds (ms) later due to misoperation of the ground element in a relay at Bridger. The relay was later was removed from service. The component that failed was a local delay timer in the ground element. Redundant primary protective devices are in service to provide adequate protection.

Loss of the two lines correctly initiated a remedial action scheme (RAS) that removed two generating units from service (Nos. 2 & 4) at Bridger (generating 1,040 MW total), bypassed the series capacitor at Burns and segment No.3 of the Borah series capacitor, and inserted the 175 MVAr Kinport shunt capacitor.

Normal generation response to the frequency deviation (59.9 Hz) resulted in replacing this Bridger generation with generation from throughout the entire Western Interconnection.

The next recorded event (1424:38.99) was system protection opening the 230 kV Round Up – LaGrande line due to misoperation of a zone 3 relay at Round Up. Voltage at the LaGrande 230 kV bus dropped from 220 kV, following the removal from service of the Bridger units, to 210 kV after the LaGrande line opened. Investigation by Bonneville Power Administration (BPA) personnel revealed a faulty phase-to-phase impedance element. Careful investigation discovered corrosion under the crimp-on lug to the phase-to-phase voltage restraint element. This corrosion effectively resulted in an open restraint circuit, which caused the phase-to-phase impedance element to close. The relay is supervised by a fault detector, so the failure was not apparent until a disturbance occurred that created enough current to operate the fault detector and lasted long enough for the relay to time out. The relay was replaced. This relay was last tested and calibrated on March 9, 1996. Corrosion of crimp-on lugs is not a common problem and is not one that would be detected by routine maintenance.

BPA began receiving low voltage alarms throughout its system. At 1424:42 the supervisory control and data acquisition (SCADA) system sounded alarms that the voltage at BPA's Anaconda Substation dropped to 219 kV and the Rattle Snake voltage was 224 kV. At 1424:47, 230 kV shunt capacitors at Anaconda were energized via a voltage control relay. In eastern Idaho, BPA's Lost River 69 kV sounded an alarm at 63 kV, Heyburn sounded an alarm nine seconds later at 134 kV, and three seconds later Spar Canyon sounded an alarm at 217 kV. In Eastern Oregon, McNary sounded an alarm at 238 kV, and at 1424:45 LaPine sounded an alarm at 114 kV and Harney at 109 kV. In southern Oregon, Warner reported high voltage (242 kV) at 1424:59.

The redistribution of flows that followed resulted in 300 MW of increased loading on the 230 kV lines from Oregon and Washington to Idaho. Correspondingly, flows on the four 230 kV Brownlee – Boise Bench lines into the Boise area increased to 1,320 MVA (900 amps at about 212 kV). Flows on the 230 kV Antelope – Mill Creek line between Montana and Idaho measured at the Mill Creek end, increased to 377 MVA (990 amps at about 220 kV). In addition, the flow on the 500 kV Midpoint – Summer Lake line increased by 400 MW into Idaho.

The 345 kV Humboldt – Midpoint line between northern Nevada and southern Idaho picked up 72 MW of the dropped Bridger generation (import into SPP on the tie went from 304 MW to 232 MW). Of the 72 MW, 52 MW flowed into northern Nevada via the west SPP – PG&E (Pacific Gas & Electric Company) ties, 4 MW via the east SPP – PACE (PacifiCorp East) tie and 4 MW via the south SPP – SCE (Southern California Edison Company) ties. The remaining 12 MW came from Sierra Pacific's frequency response characteristic.

At about 1424:51, system protection removed a C.J. Strike unit (26 MW) from service due to field excitation over current. At about 1425:01 a second 26 MW unit was removed from service at C.J. Strike for the same reason.

The 230 kV Mill Creek – Antelope line opened at 1425:01.052. The line was removed from service by a zone 3 impedance relay (timed out) at Mill Creek due to a high load condition input to the three-phase distance characteristic of the relay.

During the period following the Mill Creek – Antelope line opening, the flow from Oregon to Idaho on the Midpoint – Summer Lake line increased an additional l00 MW (500 total increase). About 70% of the additional flow came from northern Oregon on the John Day – Summer Lake section of the California–Oregon Intertie (COI) and 30% came because of decreased flows to California on the Summer Lake–Malin section of the COI.

Following the opening of the Mill Creek – Antelope line, about 23 seconds after the Bridger units were removed from service, the voltage began to collapse rapidly in the Boise, Idaho area and on the Oregon section of the California–Oregon Intertie. See Malin and Boise area voltage plots (Figure 3).

Also, following the Mill Creek – Antelope line opening, reactive power flow on the 345 kV Valmy – Midpoint line showed a shift of 171 MVAr from Valmy in northern Nevada toward Midpoint, Idaho. This shift coincides with the beginning of the voltage collapse in the Boise area. The reactive power was primarily generated at Valmy units Nos.1 & 2. Voltage at the 345 kV Humboldt station dropped 9% prior to 1425:06 (as captured by SCADA).

The low voltage enable the Celilo HVDC RAS shunt capacitor bank insertion at Malin armed within 0.5 seconds from the Mill Creek – Antelope line opening.

At about 1425:02, the third unit at C.J. Strike (26 MW) also was removed from service due to field excitation over current. In addition, two McNary units were removed from service (130 MW) at 1425:03.2 due to suspected loss of excitation. At 1425:05.5, another 60 MW unit at McNary was removed for the same reasons. At the same time as, or immediately after system separation, two more McNary units were removed (120 MW).

The four 230 kV Brownlee – Boise Bench lines were opened by impedance relays over the period from 1425:04.404 to 1425:05.237. The first two lines (Nos.3 & 1) were removed from service by reverse zone 3 impedance relays at Boise Bench. The third line (No.2) was opened by a zone 2 relay at Brownlee, and the last line (No.4) was opened by a permissive over-reach scheme at both ends. The 230 kV Oxbow – Lolo and Hells Canyon – Walla Walla lines were removed from service by zone 2 distance relays at 1425:05.504 and 1425:05.620, which separated the 230 kV path between the Northwest and Idaho.

At 1425:05.250, the 500 kV Malin shunt capacitor group 3 was switched into service via automatic voltage control. At 1425:05.700, the 115 kV Harney – Redmond terminal was removed from service and the Fort Rock Series Capacitors inserted on all three lines south of Grizzly one to three cycles later.

At Celilo, collapsing voltages affected the Pacific DC Intertie (PDCI) . In an attempt to maintain electricity flows, the dc line controls automatically raised the line current. Once the maximum limit of 3,100 amps was reached, the dc line was unable to maintain transfer levels and transfers reduced in conjunction with decreasing voltages. The effect of this action was to place further burden on the ac system.

At 1425:06.57, the Celilo DC RAS controller armed for a 10-second sliding-window algorithm. At 1425:06.72, Celilo detected an ac overload condition and the 20-minute electricity loss integrated algorithm initiated just prior to the Malin – Round Mountain line openings.

In the five-second period prior to the California – Oregon Intertie separation, reactive flows increased from 400 to 2,400 MVAr from California into Oregon as a result of collapsing voltages in southern Oregon. During this same period, Midpoint – Summer Lake reactive flows increased from 170 to 300 MVAr into Midpoint.

The separation of the California – Oregon Intertie began when the 500 kV Malin – Round Mountain No.2 line opened at Malin at 1425:06.787. opening was followed six milliseconds later by the opening of the Malin – Round Mountain No.1 line at Malin. These lines were opened by an under-impedance switch into fault logic. The 500 kV Captain Jack –Olinda line was opened 87 ms later, by positive sequence relay action at 1425:06.880.

Loss of the COI activated a RAS, which tripped 2,447 MW of Northwest generation and inserted the Chief Joseph Dynamic Brake. In addition, a signal was sent to the out-of-service Four Corners NE/SE separation scheme.

At this point, flows on the Summer Lake – Malin line reversed to feed Summer Lake. At 1425:06.901, the Malin shunt capacitor group 4 inserted in response to the DC-RAS signal. In addition, the Fort Rock series capacitors inserted on all three lines south of Grizzly one to three cycles later.

At 1425:06.900, the Dillon – Big Grassy 161 kV line was opened by an impedance relay, thus separating Montana from eastern Idaho.

The Midpoint – Summer Lake 500 kV line opened at 1425:07.020 by a zone 1 positive sequence distance relay. This action disconnected the 500 kV tie between southern Oregon and Idaho.

Following the Captain Jack – Olinda line opening by system protection, the low voltage problem on the COI became a high voltage problem at Malin, and the disturbance changed to transient stability except in Idaho, where the voltage collapsed. The ensuing high voltage resulted in an arrester failure at Malin on the PacifiCorp West Summer Lake line reactor, and at 1425:07.217, system protection opened the 500 kV Summer Lake – Malin line. This action was followed by the opening of 500 kV Captain Jack – Meridian line at 1425:07.330 and the 500 kV Grizzly – Summer Lake line at 1425:07.344. The Captain Jack 500 kV circuit breaker (Olinda line) cleared the adjoining positions due to breaker failure in the open position. The Malin 500 kV shunt capacitors opened on over current after four seconds. Malin circuit breaker (for shunt capacitor group four) began arcing around the breaker housing, causing the breaker to fail clearing the Malin north bus. Also, on shunt capacitor group 3, six capacitor cells, 37 fuses, and six fuse holders failed.

As an electricity surge started through northern Nevada toward southern Idaho, the voltage dropped rapidly on the north 345 kV tie. About 168 MW of northern Nevada demand was shed during the transient low voltage (believed to be the result of motor contactors dropping out, etc.).

In northern Wyoming, the 161 kV Yellowtail – Rimrock and the 230 kV Yellowtail – Billings and Yellowtail – Crossover lines were opened by out-of-step relay action between 1425:07.207 to about 1425:07.395, separating Wyoming from Montana.

The above line openings caused the formation of two islands. One island contained Montana, Washington, Oregon, northern Idaho, British Columbia, and Alberta (Island 2). The other island contained the rest of WSCC.

The 345 kV Borah – Bridger line opened at 1425:07.329 separating the remaining Bridger generation from Idaho. At 1425:07.67, when frequency dropped below 59.3 Hz for 0.1 second, Sierra Pacific's first step of under frequency load shedding operated, dropping 160 MW of firm demand.

The first line opening between the Idaho – Utah regions occurred at 1425:07.760 when the 345 kV Borah – Ben Lomond line opened at Borah. Although this line normally would be transfer opened by the Treasureton out-of-step scheme, it actually opned 70 ms before that scheme activated at 1425:07.790. The Treasureton scheme opened the 230 kV Treasureton – Brady line, the 138 kV Wheelon – American Falls line, the three 138 kV Treasureton – Grace lines, separated the 345 and 230 kV Jim Bridger switchyards (the generators are tied to the 345 kV bus) and shed PacifiCorp's Monsanto demand in southeastern Idaho. These actions separated the PacifiCorp system in southeastern Idaho, leaving its demands on the north side of the split tied to the Idaho Power Company system. On the south side of the split, the PacifiCorp system in southeastern Idaho, Wyoming, and Utah remained tied together. At 1425:07.850, the Jim Bridger unit No.3, now isolated from any significant demand, was removed from service.

The frequency in northern Nevada (still part of the southern island) dropped an additional 0.1 Hz to just below 59.1 Hz. This drop resulted in activation of Sierra Pacific's second step of under frequency load shedding, and dropping 90 MW of additional firm demand. At this time, southern Idaho and Utah were still tied via the northern Nevada transmission grid.

Isolated from most of its generation, the remaining southern Idaho demand was now being supplied via northern Nevada. The flow on the Humboldt – Midpoint 345 kV line went from 304 MW into Nevada (pre-disturbance) to 364 MW into Idaho just prior to Valmy – Coyote Creek opening (a shift of 670 MW). This shift in load flow was supplied by Sierra Pacific's other ties. These ties supplied 165 MW of generation, 250 MW of under frequency load shedding, 168 MW of load shed due to transient low voltage, and 87 MW in SPP's frequency and electricity surge response (of which 80 MW was an increase in generator output).

At 1425:08.138, the 345 kV Valmy – Coyote Creek line in northern Nevada opened. In northern Nevada, the 230 kV Ft. Churchill – Austin line was removed from service at 1425:08.150. This line opening made the final separation between southern Idaho and Utah and separated northern Nevada's bulk electric system from the Utah system.

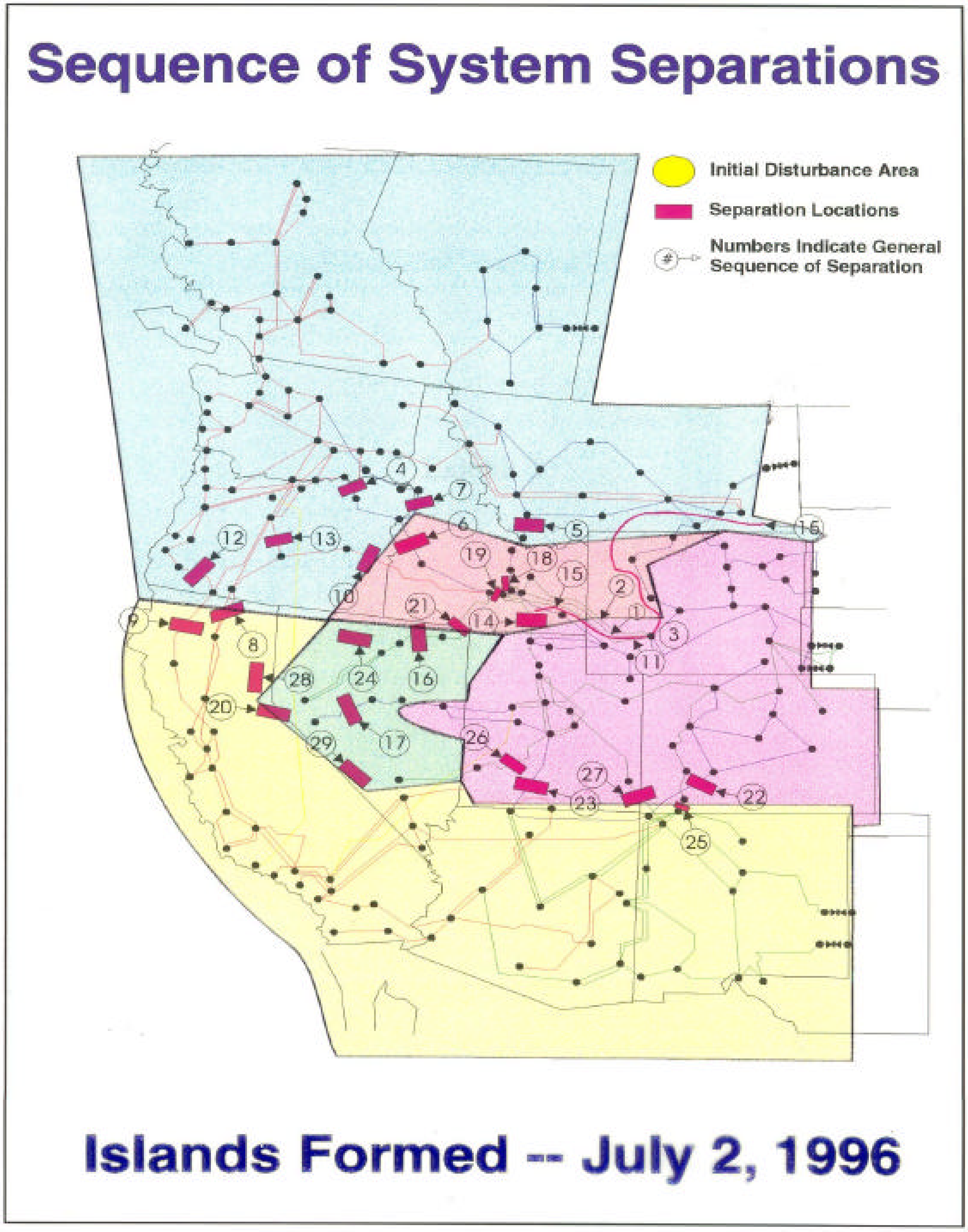

Sequence of System Separations
Initial Disturbance Area
Separation Locations
Numbers Indicate General Sequence of Separation
Islands Formed -- July 2, 1996

Figure 1

In southern Idaho, the Idaho Power Company system continued to break up and shed demand due to low voltage. The 345 kV Kinport – Midpoint line opened at 1425:08.156. At 1425:08.167, the Borah – Adelaide-Midpoint No.1 line opened, followed by the No.2 line at 1425:08.182. These actions effectively separated the backbone transmission system between eastern and western Idaho. About 300 to 400 MW of generation in southern Idaho was still on line at this time. Idaho and Nevada continued to be tied together through the 120 kV system in series with the 345 kV line from Coyote Creek to Midpoint.

Both Idaho and Nevada were still tied to the southern island through SPP's ties to California via the weak 120 kV California – Summit, 120 kV North Truckee – Summit, and 60 kV Truckee – Summit ties. At about 1425:08.300, the 120 kV ties were opened by out-of-step relays. The 60 kV tie also opened. At 1425:09.255, the 345 kV Humboldt – Midpoint line was removed from service at Midpoint due to instability. An additional 55 MW of transmission dependent demand was shed as part of SPP's remedial action scheme for loss of the Humboldt – Midpoint line.

When the Humboldt – Midpoint line opened, the Idaho (Island 4) and northern Nevada (Island 5) islands were formed, leaving the Western Interconnection separated into four islands. At this point, the northern Nevada island was in an "high frequency" condition.

The Rocky Mountain area was still connected with Arizona/California. The entire southern island was about 5,000 MW deficient in generating resources. The frequency in this island declined to 59.2 Hz at 1425:100. Under frequency load shedding of about 3,000 MW occurred in Utah and Colorado. The resultant excess generation in the Rocky Mountain area tried to flow to the Arizona/California area, which was still deficient in generation. This surge in generation flow caused an out-of-step line separation across the TOT 2 Path, (Utah/Colorado, Arizona/New Mexico/Nevada interface). This out-of-step electricity surge (at 1425:11) opened the 345 kV Waterflow – Hesperus, Pinto – Four Corners, and Red Butte – Harry Allen lines, the 230 kV Lost Canyon – Curecanti and Sigurd – Glen Canyon lines, and the 115 kV Durango – Glade Tap line. Sierra Pacific's 55 kV ties to Southern California Edison Company opened on low voltage due to the out-of-step swing.

The foregoing actions completed the formation of two more islands — the Utah, Colorado, Wyoming, western South Dakota, western Nebraska island (Island 3), and the California, Baja California, southern Nevada, Arizona, New Mexico, El Paso island (Island 1). Formation of all five islands now was complete.

Summary of Demand Shed Within Islands

Island 1

Within Island 1, frequency dropped to 59.1 Hz and under frequency load shedding occurred with Pacific Gas & Electric Company shedding 2,400 MW and Southern California Edison Company shedding 505 MW. A total of about 4,484 MW were shed affecting about 1,183,000 customers. Over 90% of the demand was restored within 30 minutes and all demand was restored within 21/2 hours.

Island 2

Another major island consisted of Washington, Oregon, Montana, British Columbia, and Alberta. About 3,900 MW of generation was automatically removed from service in this island by over frequency relays and by the remedial action scheme that monitors the California-Oregon Intertie. Impact on customers was minimal. An estimated 7,452 customers (100 MW) were interrupted over a period ranging from minutes to about one hour. About 7 MW of firm BPA demand and 3 MW of an industrial customers demand at the Cowlitz County PUD No.1 was shed due to low voltage.

SEQUENCE OF SYSTEM SEPARATIONS FOR JULY 2, 1996, DISTURBANCE ON THE WESTERN INTERCONNECTION			
Sequence Number	Time	Unit/Line	Difference from Time = 0
1	1424:37.185	Kinport-Jim Bridger 345 kV line tripped for B-ph fault	0000:00.000
2	1424:37.200	Jim Bridger-Goshen 345 kV line tripped	0000:00.015
3	1424:37.206	Jim Bridger units 2 & 4 tripped by remedial action scheme	0000.00.021
4	1424:38.995	LaGrande-Roundup 230 kV line tripped	0000:01.810
5	1425:01.052	Anaconda-Amps 230 kV line tripped Dillon-Big Grassy line tripped	0000:23.867
6	1425:04.404 1425:04.521 1425:05.053 1425:05.237	Boise Bench-Brownlee 230 kV line No. 3 tripped Boise Bench-Brownlee 230 kV line No. 1 tripped Boise Bench-Brownlee 230 kV line No. 2 tripped Boise Bench-Brownlee 230 kV line No. 4 tripped	0000:27.219 0000:27.336 0000:27.868 0000:28.052
7	1425:05.504	Hells Canyon-Walla Walla 230 kV line trip	0000:28.319
8	1425:06.787 1425:06.793	Malin-Round Mountain 500 kV line No. 2 tripped Malin-Round Mountain 500 kV line No. 1 tripped	0000:29.602 0000:29.608
9	1425:06.880	Captain Jack-Olinda 500 kV line tripped	0000:29.695
10	1425:07.020	Midpoint-Summer Lake 500 kV line tripped	0000:29.835
11	1425:07.329	Borah-Bridger 345 kV line tripped	0000:30.144
12	1425:07.330	Captain Jack-Meridian 500 kV line tripped	0000:30.145
13	1425:07.344	Grizzley-Summer Lake 500 kV line tripped	0000:30.159
14	1425:07.789	Borah-Ben Lomond 345 kV line tripped	0000:30.604
15	1425:07.792	Brady-Treasureton remedial action scheme takes affect	0000:30.607
16	1425:08.138	Coyote Creek-Valmy 345 kV line tripped	0000:30.953
17	1425:08.150	Ft. Churchill-Austin 230 kV line tripped	0000:30.965
18	1425:08.156	Midpoint-Kinport 345 kV line tripped	0000:30.971
19	1425:08.230 1425:08.279	Midpoint-Borah-Adelaide No. 2 345 kV line tripped Midpoint-Borah-Adelaide No. 1 345 kV line tripped	0000:31.045 0000:31.094
20	1425:09.000	North Truckee-Summit line tripped	0000:31.815
21	1425:09.255	Midpoint-Humboldt 345 kV line tripped	0000:32.070
22	1425:10.837	Lost Canyon-Curecanti 230 kV line tripped	0000:33.652
23	1425:10.980	Sigurd-Glen Canyon 230 kV line tripped	0000:33.795
24	1425:11.005	Winnemuca 120 kV line tripped	0000:33.820
25	1425:11.101	Hesperus-Water Flow 345 kV line tripped	0000:33.916
26	1425:11.230	Harry Allen-Red Butte 345 kV line tripped	0000:34.045
27	1425:11.300	Pinto-Four Corners 345 kV line tripped	0000:34.115
28	1425:13.000	California-Summit 120 kV line tripped	0000:35.815
29	1425:37.185	Silver Peak-Control line tripped	0001:00.000

Figure 2

Batch Plotter (1-10)
Last modified on 7/11/96 at 14:52

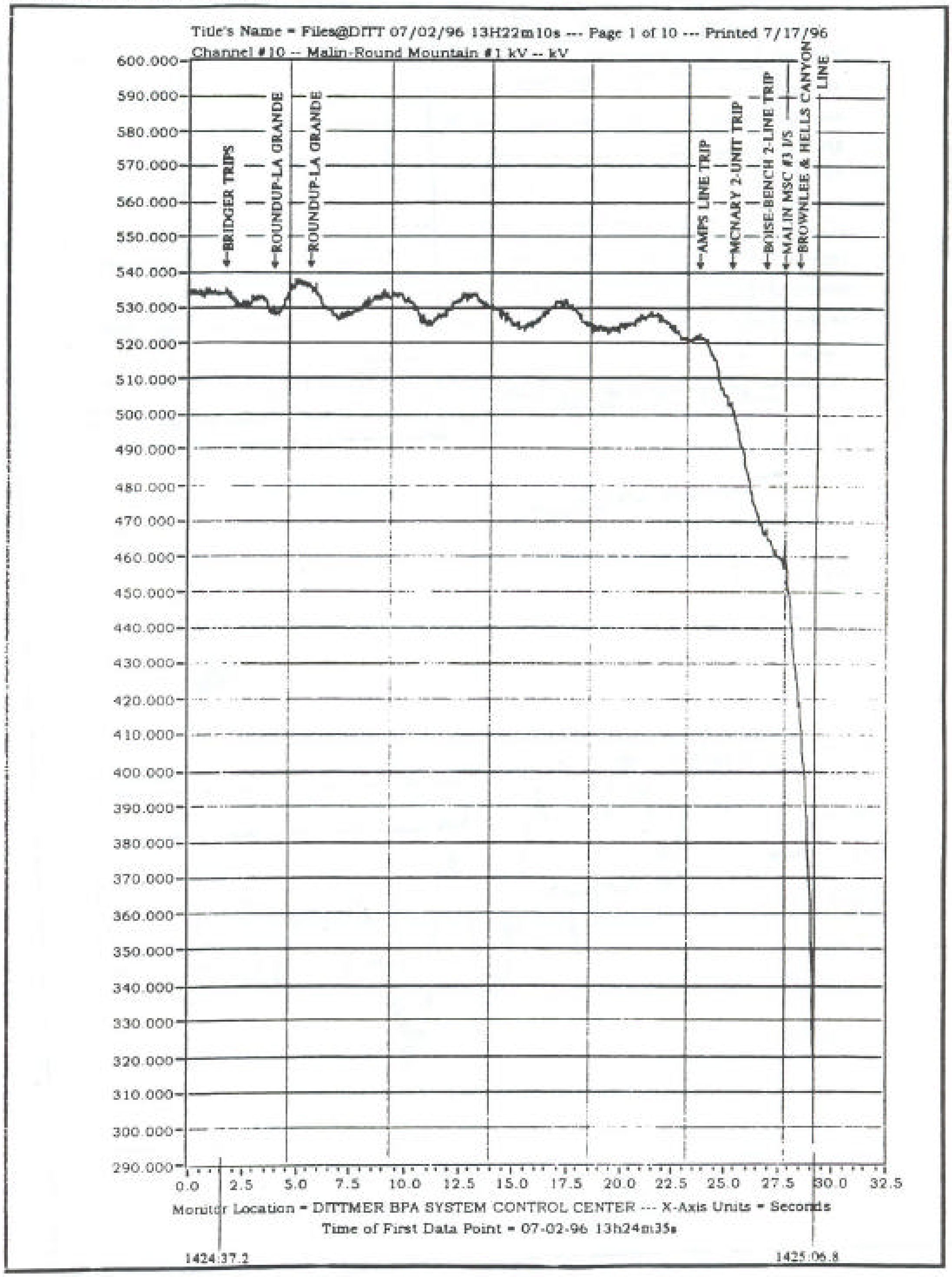


Figure 3

Island 3

Island 3 included Utah, Colorado, Wyoming, western Nebraska, and western South Dakota. While islanded with Arizona/California, the frequency dropped to 59.2 Hz and as much as 3,348 MW of demand was shed, mostly due to under frequency, along with over voltage and manual load shedding. After separating from Arizona/California, the frequency went as high as 61.1 Hz and 2,000 MW of generation was removed from service in the island for various reasons. The frequency remained high for about six minutes. With demand restoration, generation ramping down, and 2,000 MW of generation removed from service, the frequency again fell as low as 59.3 Hz. This drop resulted in under frequency load shedding followed by additional demand being manually shed in the island in an effort to restore proper frequency. The under frequency load shedding operated as designed and frequency recovered to 59.35. At this time, various generator under frequency protection schemes began timing (59.4 Hz for 180 seconds). The frequency remained at 59.35 Hz for 120 seconds and leveled off at 59.5 Hz. After islanding occurred, ramping the Stegall (11 minutes after islanding) and Virginia Smith HVDC (22 minutes after standing islanding) ties in the wrong direction for one to three minutes exacerbated the island frequency condition . About 100 MW was being exported to rather than being imported from MAPP.

Island 4

The fourth island was formed in southern Idaho and a small part of eastern Oregon where virtually all customer demand and generation was interrupted. A small portion of BPA customer demand at LaGrande remained connected to six western Idaho generators that remained on line at Hells Canyon, Oxbow, and Brownlee. A portion of PacifiCorp's demand in southeastern Idaho remained in this island, but did not have electric service. About 3,368 MW of demand (425,000 customers) was interrupted. Idaho Power Company lost all customer demand in Idaho and radially served demand located in northern Nevada as well as a small part of eastern Oregon.

BPA customer demand in the LaGrande, Baker, John Day, and Bums was in a sub-island carried by IPC's Hells Canyon complex generation. Following the Roundup – LaGrande and Mill Creek – Antelope line openings, 40 MW of demand was dropped due to extremely low voltage at LaGrande. One customer lost 14 distribution arresters in the LaGrande and Baker areas due to high voltage. This same customer removed from service its West John Day and Bums (Hines) demands via over voltage protection. The Baker demand was shed at 1455 and stayed out till 1647.

Island 5

A fifth island was formed in northern Nevada at 1425:09.255. Before electric service restoration could be completed, SPP demand dropped 550 MW. Of this amount, about 418 MW was shed during the transient frequency and voltage dips, which coincided with an electricity surge going through northern Nevada toward southern Idaho. The 418 MW loss occurred as the first island began to separate from the rest of the WSCC at 1425:07.395. Of the 418 MW, 250 MW was comprised of under frequency load shedding; the remaining 168 MW was uncontrolled loss of voltage sensitive demands. Voltage sensitive demands consist primarily of motor load, which is shed when motor contactors open during severe low voltage. Although the loss of 168 MW of customer demand was scattered throughout northern Nevada, 103 MW was shed in the system north of Valmy. At 1425:09.255, the 345 kV Humboldt – Midpoint tie opened when transmission between southern Idaho and northern Nevada became unstable. This instability initiated a RAS that successfully shed 55 MW of transmission dependent demand. Frequency jumped to 60.75 Hz in northern Nevada once the island formed. At 1427:11, 17 MW were shed on the 120 kV system south of Anaconda Moly due to over voltage. At 1430:26, the 230 kV Austin-Frontier line opened at the Austin end due to over voltage and sent a signal to Gonder to open the Gonder end of the 230 kV Gonder – Machecek line. This action removed from service 20 MW of demand from the 230 kV system between Fort Churchill and Gonder. Gonder demands were still being served via Utah. An additional 40 MW was shed on under frequency load shedding during the restoration sequence.

July 3 Disturbance

The following day, July 3, 1996, at 2:03 p.m., a similar chain of events began. The 345 kV Jim Bridger – Kinport line again flashed (arced) to a tree and was automatically disconnected by protective devices, clearing the short circuit. At nearly the same time, the 345 kV Jim Bridger – Goshen line was automatically disconnected due to misoperation of the same protective device that misoperated on July 2. The outage of two of the three 345 kV lines west of the Jim Bridger power plant activated the Bridger remedial action scheme, automatically disconnecting two of the four Jim Bridger units.

Operating conditions on July 3 were different from those on July 2. Schedule limits on the California-Oregon Intertie were reduced to 4,000 MW north to south pending the results of technical studies conducted to analyze the prevailing operating conditions. Interchange schedules through Idaho from the Northwest were reduced and generation patterns in the Northwest were changed. Brownlee generating unit No.5 in western Idaho was returned to service following a forced outage and provided additional voltage support.

Following the loss of the Bridger lines and generation, the Brownlee generating plant in western Idaho increased to maximum reactive output limits and was providing critical voltage support for the Boise area. Voltage in the Boise area stabilized at 224 kV. The Brownlee plant operators received maximum excitation limit alarms and became concerned about the amount of reactive power supplied by their units. As a precautionary measure to avoid possible unit shedding of critical generation, the operators placed the voltage regulators in “manual” operation, and reduced the voltage set point. Although this action did relieve stress on the generating units, it was undesirable from an interconnected system standpoint in that it reduced reactive support to the Boise area, which contributed to the need for manual load shedding to arrest declining voltage. This action induced a steady voltage decline to 205 kV over a three-minute period.

At this time, system dispatcher action at the control center shed 600 MW over the next two minutes to arrest voltage decline in Boise. Voltages immediately recovered to 230 kV upon the completion of the load shed. It is not clear whether the IPC system operators would have had to resort to shedding firm demand had the Brownlee plant continued to contribute full reactive support.

All customer demand was restored within 60 minutes, except an interruptible industrial customer that was restricted to half demand until the Jim Bridger generation was restored at about 5:30 p.m.

Conclusions and Recommendations

Due to the significant nature of this system-wide disturbance, 24 conclusions and 44 recommendations were made. They are all in the final WSCC report dated September 19, 1996. The Disturbance Analysis Working Group selected four key conclusions and associated recommendations to give the reader a sample of the problems identified.

Conclusion:

1. The simultaneous combination of operating conditions on July 2, characterized by record peak summer demands in Idaho and Utah, maximum water flow conditions in the Pacific Northwest, high north-to-south electricity transfers on the California-Oregon ac and dc interties, transfers from the Northwest to Idaho and Utah, high volumes of electricity transfers from Canada to the Northwest, and high amounts of thermal generation in Wyoming and Utah were not anticipated or studied. The speed of the collapse seen July 2 was not observed in this region and was not anticipated in studies.

Insufficient voltage support in the Northwest and Idaho for the operating conditions of July 2 was a primary factor that contributed to the widespread impact of this disturbance. The initiating event, the near simultaneous outage of two 345 kV Jim Bridger lines, should not have resulted in the system separations and loss of demand experienced on July 2, 1996.

Recommendation:

Idaho Power Company, PacifiCorp, Bonneville Power Administration, and other Northwest area entities shall reduce scheduled electricity transfers at a safe and prudent level until studies have been conducted to determine the maximum simultaneous transfer capability limits and to thoroughly evaluate operating conditions actually observed on July 2.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy

Conclusion:

2. WSCC and its member systems conduct hundreds of studies each year to access system reliability and prepare for varying seasonal operating conditions. However, the unusual combination of operating conditions and disturbance conditions encountered on July 2 were not anticipated in studies conducted prior to the disturbance.

Recommendation:

The WSCC Planning Coordination Committee/Joint Guidance Committee shall thoroughly review WSCC's and its members' processes for studying upcoming system operating conditions. Any changes will be implemented as needed to ensure that these processes for identifying unusual operating conditions are appropriate, and that credible disturbances are adequately studied prior to encountering them in real-time operating conditions.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 2 — Transmission, B. Voltage and Reactive Control
NERC Operating Policy 4 — System Coordination, D. System Protection Coordination
NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy

Conclusion:

12. The voltage collapse in the Idaho Power Company system on July 2 resulted in a black out of the IPC system. On July 3, IPC dispatchers demonstrated the viability of load shedding in preventing voltage collapse.

Recommendation:

IPC shall consider implementing automatic under voltage load shedding programs to prevent the spread of voltage collapse. Other WSCC members shall learn from IPC's experience and also give consideration to implementing under voltage load shedding programs, as appropriate. WSCC members shall report to WSCC staff the measures implemented.

Refer to: NERC Operating Policy 5 — Emergency Operations, D. Separation from the Interconnection
NERC Operating Policy 6 — Operations Planning, C. Automatic Load Shedding
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, II. Resources, Guides, B. Demand-Side Resources

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

Conclusion:

21. This disturbance affected a wide geographic area and highlights the need for an improved security monitoring process within the Western Interconnection to monitor real-time operating conditions on a broader scale than is currently accomplished by individual control areas.

Recommendation:

WSCC's Security Process Task Force shall review what is required to implement a security monitoring process in the Western Interconnection, to monitor operating conditions on a regional scale and promote interconnected system reliability. The Task Force shall recommend appropriate actions.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 2 — Transmission, B. Voltage and Reactive Control
NERC Operating Policy 4 — System Coordination, A. Monitoring System Conditions
NERC Operating Policy 4 — System Coordination, B. Coordination With Other Systems — Normal Operations
NERC Operating Policy 5 — Emergency Operations, A. Coordination With Other Systems
NERC Operating Policy 6 — Operations Planning, C. Automatic Load Shedding
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, B. Security
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, C. Coordination

Anyone interested in obtaining a hard copy of the WSCC disturbance report is asked to submit in writing a request to the WECC Technical Staff at the Western Electricity Coordinating Council (formerly the Western Systems Coordinating Council) office.

BIG RIVERS ELECTRIC CORPORATION DISTURBANCE — AUGUST 7, 1996

Summary

Big Rivers Electric Corporation (BREC) experienced a system disturbance that islanded part of its system on Wednesday, August 7, 1996. This disturbance resulted in the loss of a total of 347 MW of demand, consisting of 259 MW of BREC demand and 88 MW of load of Henderson Municipal Power & Light (HMPL) demand, which is within the BREC control area. System protection removed some 1,180 MW of generation within the BREC control area within the island. The outage occurred during switching to alleviate overloads on BREC ties to Southern Indiana Gas & Electric Company (SIGE) and Hoosier Energy Rural Electric Cooperative, Inc. (HE).

As a result of this outage, BREC has taken a number of internal corrective actions, and is pursuing improvements to system security in the future through the participation in the development of the Midwest Independent System Operator (ISO).

ECAR also will pursue improvements in communicating study results to system operation personnel, reemphasis on the importance of proper right-of-way and protection equipment maintenance, and improvements in the MAIN-ECAR-TVA (MET) line loading relief procedure.

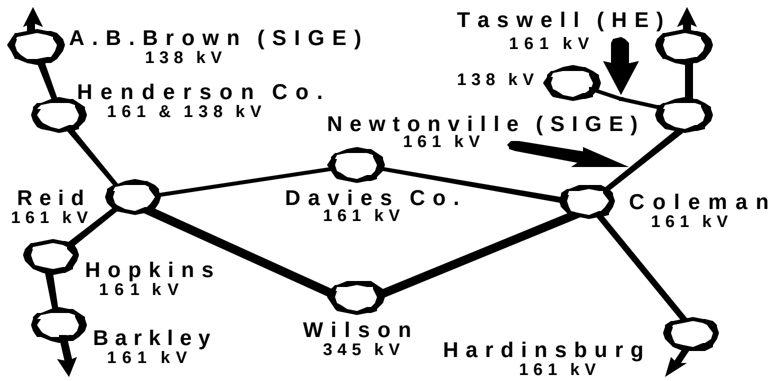
Pre-Event Conditions

Network electricity flows through the BREC system were unusual on August 7 in that they exhibited a south-to-north bias, with the BREC southern ties having lower than normal flows and the northern ties higher than normal. Typical flow bias is north-to-south during the summer.

Key Events

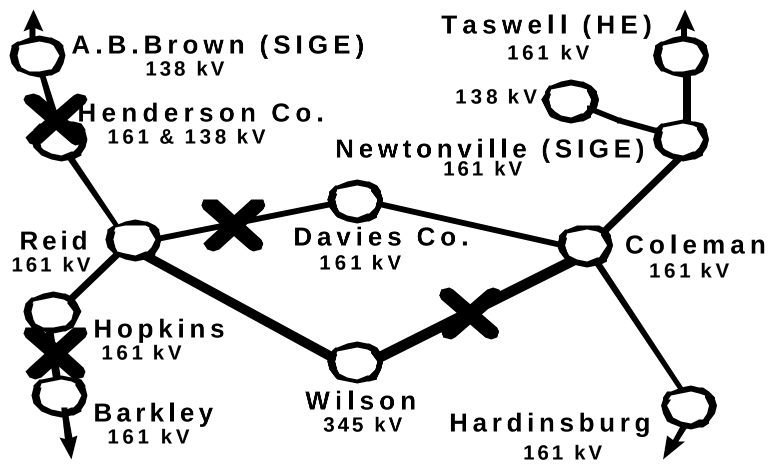
On the morning of August 7, the BREC 161 kV transmission interconnection between its Coleman station and Hoosier Energy at SIGE's Newtonville station, and the SIGE 161/138 kV tie transformer at Newtonville were heavily loaded.

Over the course of the morning, loadings on those system elements drifted upward, eventually exceeding their normal thermal ratings. At 1030 CDT, BREC redispatched internal generation to alleviate the loadings, achieving a 4% reduction on the 161 kV Coleman – Newtonville tie flow. However, across the next hourly ramping period (1050 to 1110 hours), network south-to-north flows increased by about 40 MW, eradicating the line loading relief previously achieved by the redispatch of generation. This change in flows was later attributed to an electricity transaction accepted by the BREC system operator of a 50 MW purchase from the south, coupled with a 50 MW sale to the north. This transaction resulted in a 30 MW increase in loading on the already-overloaded 161 kV Coleman – Newtonville tie to HE.



At 1105 CDT, SIGE advised BREC of its intent to open the low-side breaker on the 161/138 kV Newtonville tie transformer to protect it from damage. The BREC system operator requested five minutes to alleviate the loadings and began an immediate significant reduction in generation. Before the effects of the generation reduction could be realized, the BREC system operator opened the 345 kV Wilson – Coleman line (1109) to divert flows from the Coleman area. This operator action was premature, but the operator believed that it would alleviate the overload problem. The opening of the 345 kV Wilson – Coleman line resulted in an overload of the Reid – Davies County 161 kV line, causing it to sag into a tree about four (4) minutes after the 345 kV line was opened. The Reid – Davies County line outage caused subsequent overloads on two additional circuits, the 161 kV Hopkins County – Barkley tie line to TVA and the 161/138 kV tie transformer to SIGE at BREC's Henderson County station. System protection opened both circuits, effectively isolating or islanding a major segment of the BREC system.

The islanded section of the system suffered severe voltage and frequency swings and system protection removed all but one generator serving 12 MW of local demand in the HMPL system, resulting in loss of all 347 MW of other demand in the islanded system.



System Restoration

All BREC customers had electric service restored (47 MW) in about five minutes except for an aluminum smelter. Voltage and reactive support concerns for this industrial customer (212 MW) delayed its restoration until adequate local generation could be returned to service. The HMPL customers were returned to service in 10 to 12 minutes. All circuits opened or removed from service during the outage were returned to service by 1131, and an additional 69 kV tie that had been operated open prior to the incident was closed for additional voltage support. Throughout the incident, all protective relays operated as expected.

Generation Outages

The total amount of generation removed from service during the disturbance was 1,180 M. It comprised: Green units Nos.1 & 2 (445 MW), HMPL Station 2, units Nos.1 & 2 (Operated by BREC, 308 MW), Reid unit No.1 (52 MW), and Wilson unit No.1 (375 MW)

BREC's Coleman units 1, 2, & 3 (440 MW) was not part of the island and remained on-line through the event. Also, HMPL Station 1 unit No.6, which is connected to the HMPL 69 kV system within the islanded area, remained on line through the incident carrying about 12 MW of local HMPL demand. BREC's Reid Combustion Turbine was off-line during the outage.

Big Rivers Corrective Actions

BREC cited that following corrective actions in their internal outage report to prevent similar future occurrences:

1. BREC will participate in the organization and operation of the Midwest ISO, which will be empowered to oversee flows of neighboring utilities and take an area approach to dealing with overloads.

Refer to: NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy

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

2. BREC will be completing a new 161 kV interconnection with Kentucky Utilities by the end of 1996. This tie line offers significant benefits in strengthening BREC's interconnection capacity.

Refer to: NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy

3. BREC's management issued operational orders prohibiting the opening of its internal transmission lines and the jeopardizing customer service reliability in support of electricity exports.

Refer to: NERC Operating Policy 3 — Interchange, A. Interchange

4. BREC will increase its right-of-way clearing maintenance efforts in areas near creeks and streams where its current four-year maintenance cycle is insufficient to keep fast growing trees from endangering line operation.

ECAR MSDTF Findings and Recommendations

The ECAR Major System Disturbance Task Force determined:

1. Finding: The main cause of the outage was operator error.
    - Failure to follow established operating procedure, i.e., reduction of generation output to alleviate overloads
    - Failure to analyze system impacts of buy/sell (south-to-north) transactions
    - Failure to use all tools at the system operator's disposal to analyze situation

Recommendation: Improve operator training in these areas.

Refer to: NERC Operating Policy 8 — Operating Personnel and Training, C. Training

2. Finding: All relay operations were correct and appropriate.

Recommendation: ECAR should emphasize among its members the importance of good relay coordination and maintenance.

Refer to: NERC Operating Policy 4 — System Coordination, B. Coordination With Other Systems — Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, D. Protection Systems

3. Finding: Inadequate tree trimming was a factor in precipitating this outage.

Recommendation: ECAR should emphasize among its members the importance of good relay coordination and maintenance.

Refer to: NERC Operating Policy 4 — System Coordination, B. Coordination With Other Systems — Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, D. Protection Systems

4. Finding: The MAIN-ECAR-TVA (MET) Line Loading Relief Procedure may have been helpful in managing these overloads.

   Heavy line loading problems caused by north-to-south electricity transfers in the BREC area during the summer of 1993 resulted in the establishment of the MET Line Loading Relief Procedure. That procedure specifically addresses north-to-south overload problems in MAIN and southern ECAR, and was incorporated in the ECAR Security Process, administered by American Electric Power (AEP) as the Security Coordinator.

Recommendations:

- Review training of ECAR system operations personnel on use of the MET procedure
- Improve the MET procedure to make it more readily usable with the Interregional Security Network and security process

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 6 — Operations Planning, B. Emergency Operations
NERC Operating Policy 8 — Operating Personnel and Training, C. Training
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, C. Coordination

5. Finding: Outage resembles a scenario analyzed in the January 1996 *Assessment of ECAR Transmission Systems Conformance to ECAR Document No. 1*: System Collapse in the BREC Area for Loss of the Wilson-Coleman 345 kV Circuit, followed by a loss of the Reid-Davies County 161 kV circuit during heavy BREC exports to Indiana. The BREC System Operator was not aware of those ECAR study results.

Recommendation: ECAR should improve dissemination of Regional and Interregional study result to system operations personnel.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 5 — Emergency Operations, A. Coordination With Other Systems
NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Operating Policy 8 — Operating Personnel and Training, C. Training
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, C. Coordination

For additional information on this event, please contact the East Central Area Reliability Agreement (ECAR) office.

WESTERN INTERCONNECTION (WSCC) SYSTEM DISTURBANCE — AUGUST 10, 1996

Summary

A major disturbance occurred in the Western Interconnection (Western Systems Coordinating Council, WSCC) at 1548 PDT, August 10, 1996 resulting in the Interconnection separating into four electrical islands (Figure 1). Conditions prior to the disturbance were marked by high summer temperatures (near or above 100 degrees Fahrenheit) in most of the Region, by heavy exports (well within known limits) from the Pacific Northwest into California and from Canada into the Pacific Northwest, and by the loss of several 500 kV lines in Oregon.

The California–Oregon Intertie (COI) North to South electricity flow was within parameters established by recent studies initiated as a result of the July 2-3, 1996 disturbance (see disturbance No.3, Page 22). The flow on the COI was about 4,350 MW and the flow on the Pacific DC Intertie (PDCI) was 2,848 MW.

Operations Prior to Disturbance

At 1401 PDT, system protection opened the 500 kV Big Eddy – Ostrander line when it flashed (arced) and grounded to a tree. The Portland General Electric Company (PGE) McLoughlin terminal of the 230 kV Big Eddy – McLoughlin line opened and reclosed for this fault, which was close to the Ostrander terminal. The Big Eddy – Ostrander line was tested and returned to service at 1403. At 1406 (Figure 2), "A" phase opened on the Big Eddy – Ostrander line, reclosed, then all three phases opened and remained out of service. PGE's Big Eddy – McLoughlin again opened and reclosed. Bonneville Power Administration (BPA) dispatcher's began to receive low voltage alarms, which were corrected by switching out of service shunt reactors and switching into service shunt capacitors.

At 1452:37, the 500 kV John Day – Marion line opened and locked out when the line flashed and grounded to a tree near Marion. Because a Marion 500 kV circuit breaker was out of service, the 500 kV Marion – Lane line was forced out of service. At 1456 the John Day – Marion line opened when it was tested.

At 1542:37, 50 minutes after the John Day – Marion line faulted, the 500 kV Keeler – Allston line opened after flashing to a tree near Keeler. At this point, five 500 kV line segments were out of service, removing several hundred MVAr of reactive support from the system while simultaneously increasing the reactive requirement as other lines picked up the electricity flow previously carried by the out of service lines. BPA dispatchers requested maximum reactive power boost from John Day and The Dalles (both hydro plants) within one minute of the Keeler – Allston opening. Prior to the Keeler – Allston trip, the 13 McNary hydro generating units were producing 860 MW and 260 MVAr.

While the BPA system voltage situation was being assessed, (BPA dispatchers were considering the possibility of COI schedule reductions), the Keeler – Allston line was tested from Allston and opened on test at 1544. The John Day substation was receiving 408 MVAr from the John Day powerhouse and Big Eddy was receiving 77 MVAr from The Dalles. The reactive output of the McNary generating units was boosted from 260 to 475 MVAr (which was over their maximum sustained MVAr output at that power level) immediately following the Keeler – Allston line opening.

At 1547:36, the 230 kV Ross – Lexington line opened when it flashed to a tree. This relay operation resulted in system protection also removing PacifiCorp's Swift generating unit (207 MW). The reactive output of the McNary units was boosted to 480 MVAr, then to 494 MVAr. The units held at this level for a short time, then system protection began removing them from service. Between 1547:40 and 1549 all 13 units were removed from service as a result of erroneous operations of a phase unbalance relay in the generator exciters. Following the loss of the McNary units, the Boardman Plant was supplying 275 MVAr in response to collapsing voltage while in constant excitation mode.

Power Oscillations

Following the removal from service of the McNary units, a mild oscillation began on the transmission system. Grand Coulee, Chief Joseph, and John Day hydro generation began to increase generation to make up the difference. When McNary generation dropped to about 350 MW, the oscillation became negatively damped. The Malin 500 kV shunt capacitor Group 3 was automatically switched in 45 seconds after the Ross – Lexington line opened. This operation raised the voltage, but the 0.224 Hz system oscillations continued to increase. Five seconds later BPA switched in a 115 kV shunt capacitor group at Walla Walla.

The PDCI also began to fluctuate in response to the ac voltage. The PDCI response during the oscillation indicated that system inertia synchronizing power was decreasing (decreasing dc power while ac power was increasing). At 1548:51, when the ac system oscillations had increased to about 1,000 MW and 60 kV peak-to-peak at Malin, the voltage collapsed. At that time, the 500 kV Buckley – Grizzly line opened via a zone one relay. Within the next two to three seconds, the ties between northern California and neighboring systems, and between Arizona/New Mexico/Nevada and Utah/Colorado opened due to out-of-step and low voltage conditions.

The opening of the 500 kV Keeler – Allston line at 1542:37 overloaded the 230 kV lines into the Portland, Oregon area and led to the opening of the 230 kV Ross – Lexington line at 1548:36. Electricity flows shifting east of the Cascades led to additional reactive demands in the McNary area and consequent removal from service of service of all 13 units at McNary. Finally, growing oscillations reached a level that opened all three lines of the COI in just over one minute.

California-Oregon Intertie Separation

One-and-a-half cycles after the Buckley – Grizzly line opened, the Malin 500 kV voltage dropped to 315 kV, and the 500 kV Malin – Round Mountain No.1 and No.2 lines opened by the traveling wave relay switch-into-fault logic at 1548:52:632. These operations were followed shortly by the opening of the 500 kV Captain Jack – Olinda line, which completed separation of the California–Oregon Intertie. The North island frequency rose to 60.9 Hz dropping to 60.4 Hz within two seconds where it remained for about 14 minutes. The frequency crossed 60 Hz three minutes later. During the disturbance, the PDCI experienced several power reductions, and at 1605:12.4, the Sylmar AC Filter Bank 4 opened due to blown fuses, which was probably caused by high harmonic current resulting from reduced voltage operation after the loss of the other valve groups. The PDCI ramp began at 1606:19 and was blocked at 1612.

Island Details

North Island

This island (Figure 1) consisted of Oregon, Washington, Idaho, Montana, Wyoming, British Columbia, Utah, Colorado, Western South Dakota, Western Nebraska, and Northern Nevada. This island was formed following the separation of the COI and out-of-step line openings on the Northeast/Southeast boundary. Shortly after the Captain Jack – Olinda line opened, the Malin south bus differential relays operated to deenergize the 500/230 kV PacifiCorp transformer, and the 500 kV Grizzly – Summer Lake line opened. All remaining lines on the Oregon section of the COI were opened between John Day and Malin. PacifiCorp lost about 450 MW of customer demand, interrupting service to 154,000 customers in portions of southern and central Oregon, and northern California. Electricity was restored to these customers between 1620 and 1701.

Northern California Island

This island was formed following out-of-step conditions and low voltages between Midway and Vincent substations two seconds after the COI separation and following separation from Sierra Pacific Power Company. At 1548:54.7, the 500 kV Midway – Vincent No.1 and No.2 lines opened when the 500 kV bus voltage at Vincent dropped to 40% of normal. The Midway – Vincent No.3 line opened 65 milliseconds later separating northern and southern California. Frequency within the Northern California Island dropped to 58.3 Hz eight minutes into the disturbance. The under frequency load shedding program within this island removed all ten blocks of customer demand, representing about 50% of the Northern California demand. The Northern California Island lost 7,937 MW of generation and 11,602 MW of demand (about 2.9 million customers).

After the initial swing, when the frequency dropped to 58.5 Hz, frequency rapidly overshot to 60.7 Hz and fluctuated slightly above 60 Hz for more than three minutes (Figure 3). Some of Pacific Gas & Electric's (PG&E) demand that was automatically shed was automatically restored after three minutes. (The PG&E load shedding program is designed to restore customer demand in three to six minutes after frequency returns to near 60 Hz.) Over the next five minutes, as demand was automatically restored and additional generation was removed from service, frequency further declined to 58.3 Hz so that the demand that had been automatically restored was removed from service again. Frequency then returned to slightly above 59.0 Hz where it began to stabilize. At 1607, frequency returned to 59.5 Hz where it stayed for about 75 minutes. At 1722, PG&E dispatchers manually shed load to bring the frequency back to normal. The low frequency in the Northern California Island prevented its reconnection with the Northern Island. From 1722 to 1732, PG&E manually shed 2,524 MW of additional customer demand. This demand was restored by 2037.

Connections to southern California were restored at 1847 when the Midway – Vincent No.1 and No.3 lines were returned to service. The Midway – Vincent No.2 line was returned to service at 1848. By 2154, 91% of the PG&E customers had electric service restored; all customers had electric service restored by 0100 on August 11.

Southern Island

This island consisted of Southern California, Arizona, New Mexico, Southern Nevada, Northern Baja, California Mexico, and El Paso, Texas. This island was formed due to out-of-step conditions and low voltage between Midway and Vincent and out-of-step conditions on the Northeast/Southeast boundary. Generation totaling 13,497 MW was removed from service, along with 15,820 MW of customer demand (about 4.2 million customers).

The frequency in the Southern Island remained below 60 Hz for over an hour (Figure 4). Salt River Project (SRP) manually shed 216 MW of demand (after removing from service 1,444 MW by under frequency relays). As the frequency in the island began to recover and several key units in the island returned to service, system demand restoration began at 1657. The frequency returned to normal at 1655. By 2142, all the demand shed in the Southern Island was restored.

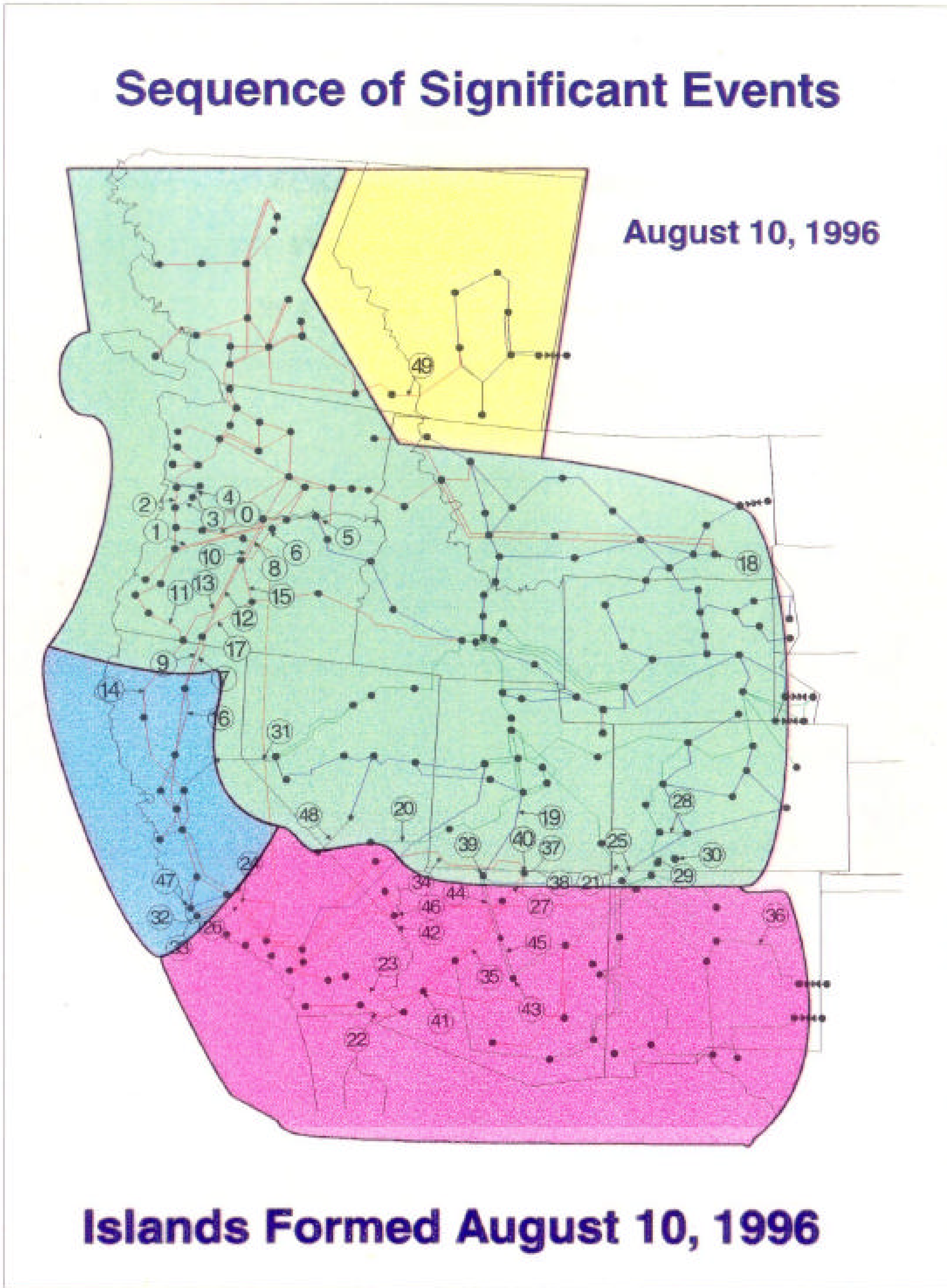

Sequence of Significant Events
August 10, 1996
Islands Formed August 10, 1996

Figure 1

SEQUENCE OF SIGNIFICANT EVENTS — AUGUST 10, 1996

EVENT NUMBER	TIME	EVENT	DIFFERENCE FROM TIME = 0 HH:MM:SS.000
0	14:06:39.769	500 kV Big Eddy-Ostrander single phase-to-ground fault, relay tripped three phases. Flashed to tree.	00:00:00.000
1	14:52:37.156	500 kV John Day-Marion single phase-to-ground fault. Flashed to tree.	00:45:57.387
2	15:42:03.139	500 kV Keeler-Allston single phase-to-ground fault; opened single pole with unsuccessful reclose. Flashed to tree.	01:35:23.370
3	15:47:29	115 kV Merwin-St. Johns line opened due to relay misoperation (Note: time is approximate)	01:40:49:231
4	15:47:36	230 kV Fault on Ross-Lexington line. Flashed to tree. Fault started small fire. **(BEGINNING OF DISTURBANCE)**	01:40:56.231
5	15:47:36 15:47:40 15:47:44 15:47:52 15:48:09	McNary trips 117 MW (2 units) - (Timing is from Event 4 for rest of table) McNary trips 215 MW (3 units) McNary trips 75 MW (1 unit) McNary trip (1 unit) McNary trip (1 unit)	00:00:00.000 00:00:04.000 00:00:08.000 00:00:16.000 00:00:33:000
6	15:48:52.588	500 kV Buckley-Grizzly line open at Buckley.	00:01:16.588
7	15:48:52.613	500 kV Malin-Round Mountain No. 2 line open at Malin.	00:01:16.613
8	15:48:52.618	500 kV John Day-Grizzly No. 1 line open at John Day; open at Grizzly at 52.633.	00:01:16.618
9	15:48:52.632	500 kV Malin-Round Mountain No. 1 line open at Malin.	00:01:16.632
10	15:48:52.641	500 kV John Day-Grizzly No. 2 line open at Grizzly; open at John Day at 52.654.	00:01:16.641
11	15:48:52.682	500 kV Captain Jack-Meridian line open at Captain Jack power circuit breaker (PCB Nos. 4983, 4986), reclose blocked.	00:01:16.682
12	15:48:52.740	500 kV Grizzly-Malin No. 2 line open at Grizzly (PCB No. 4048); open at Malin at 52.750.	00:01:16.740
13	15:48:52.778	500 kV Captain Jack-Grizzly line open at Captain Jack (PCB Nos. 4993, 4990); Grizzly open at 52.794.	00:01:16.778
14	15:48:52.782	500 kV Captain Jack-Olinda line open at Captain Jack (PCB Nos. 4977, 4980). **(COI NOW OPEN BETWEEN OREGON AND CALIFORNIA)**	00:01:16.782
15	15:48:52.878	500 kV Grizzly-Summer Lake line open at Grizzly; open at Summer Lake at 52.907.	00:01:16.878
16	15:48:53.000	500 kV Round Mountain-Table Mountain No. 2 line open ended at Round Mountain.	00:01:17.000
17	15:48:53.255	500 kV Malin-Summer Lake line opens at Summer Lake; Malin terminal opens at 53.258.	00:01:17.255
18	15:48:53.622 15:48:53.649	Colstrip Unit Nos. 3 and 4 trip off line. Colstrip Unit No. 1 trips off line.	00:01:17.622 00:01:17.649
19	15:48:53.708	Sigurd terminal of the 230 kV Glen Canyon-Sigurd line opened by out-of-step relay.	00:01:17.708
20	15:48:53.930	345 kV Red Butte-Harry Allen line opened by out-of-step relay.	00:01:17.930
21	15:48:54.415	345 kV Four Corners-Pinto line opens (at Four Corners).	00:01:18.415
22	15:48:54.576	500 kV North Gila-Imperial Valley line opens.	00:01:18.576
23	15:48:54.622	500 kV Palo Verde-Devers opens at Palo Verde; at Devers it opens at 54.625.	00:01:18.622
24	15:48:54.700	500 kV Midway-Vincent Nos. 1 and 2 lines opened by out-of-step relay.	00:01:18.700
25	15:48:54.703	230 kV Shiprock-Lost Canyon line opened by out-of-step relay.	00:01:18.703
26	15:48:54.765	500 kV Midway-Vincent No. 3 line opens due to voltage collapse. **(NORTHERN CALIFORNIA NOW SEPARATED FROM SOUTHERN CALIFORNIA)**	00:01:18.765
27	15:48:54.825	500 kV Navajo-Moenkopi line opens at Navajo.	00:01:18.825
28	15:48:54.846	Curecanti terminal of the 115 kV Curecanti-Montrose line opens (Zone 1).	00:01:18.846
29	15:48:54.936	Hesperus terminal of the 345 kV Waterflow-Hesperus line and both terminals of 345 kV Montrose-Hesperus line opened by out-of-step relays.	00:01:18.936
30	15:48:54.938	City of Farmington, NM, Glade Tap-Durango 115 kV tie opened at Glade Tap by out-of-step relays (two paths now open).	00:01:18.938
31	15:48:55	120 kV North Truckee-Summit line, 120 kV California-Summit line, and 60 kV Truckee-Tahoe Donner line open.	00:01:19:000
32	15:48:55.141	Diablo Canyon Unit No. 2 trips off line.	00:01:19.141
33	15:48:55.405	Diablo Canyon Unit No. 1 trips off line.	00:01:19.405
34	15:48:58.496	500 kV Navajo-McCullough line opens at Navajo.	00:01:22.496
35	15:48:58.803	500 kV Navajo-Westwing line opens at Navajo.	00:01:22.803
36	15:48:59.000	345 kV BB line and Blackwater dc Converter trip out of service.	00:01:23.000
37	15:48:59.341	Navajo Unit No. 1 trips off line.	00:01:23.341
38	15:48:59.492	Navajo Unit No. 2 trips off line.	00:01:23.492
39	15:49:00.000	Glen Canyon Unit Nos. 2, 5, 7, and 8 are removed from service by a remedial action scheme while carrying about 430 MW. These trips were caused by loss of both 345 kV Glen Canyon-Flagstaff lines.	00:01:24.000
40	15:49:07.140	Navajo Unit No. 3 trips off line.	00:01:31.140
41	15:49:13.315 15:49:13.405	Palo Verde Unit No. 1 trips off line. Palo Verde Unit No. 3 trips off line.	00:01:37.315 00:01:37.405
42	15:49:14.000	Hoover Dam: Units 2, 3, and 8 trip off line.	00:01:38.000
43	15:49:20.830	Pinnacle Peak-Pinnacle Peak (WAPA).	00:01:44.830
44	15:49:45.271	Glen Canyon terminals of the 345 kV Glen Canyon-Flagstaff Nos. 1 and 2 lines open.	00:02:09.271
45	15:49:48.000	Pinnacle Peak: Flagstaff-Pinnacle Peak No. 1 Line PCB Nos. 1092, 1196 opened. Flagstaff-Pinnacle Peak No. 2 Line PCB Nos. 1492, 1596 opened.	00:02:12.000
46	15:49:59.723	Mohave Unit No. 2 trips off line.	00:02:23.723
47	15:50:00.000	Hunters Point Unit No. 2 and Morro Bay Unit Nos. 1–4 trip off line.	00:02:24.000
48	15:50:00.000	55 kV Silver Peak tie opens at Silver Peak.	00:02:24.000
49	15:54	500 kV Cranbrook-Langdon line opens. **(FINAL SYSTEM SEPARATION)**	00:06:24:000

Figure 2

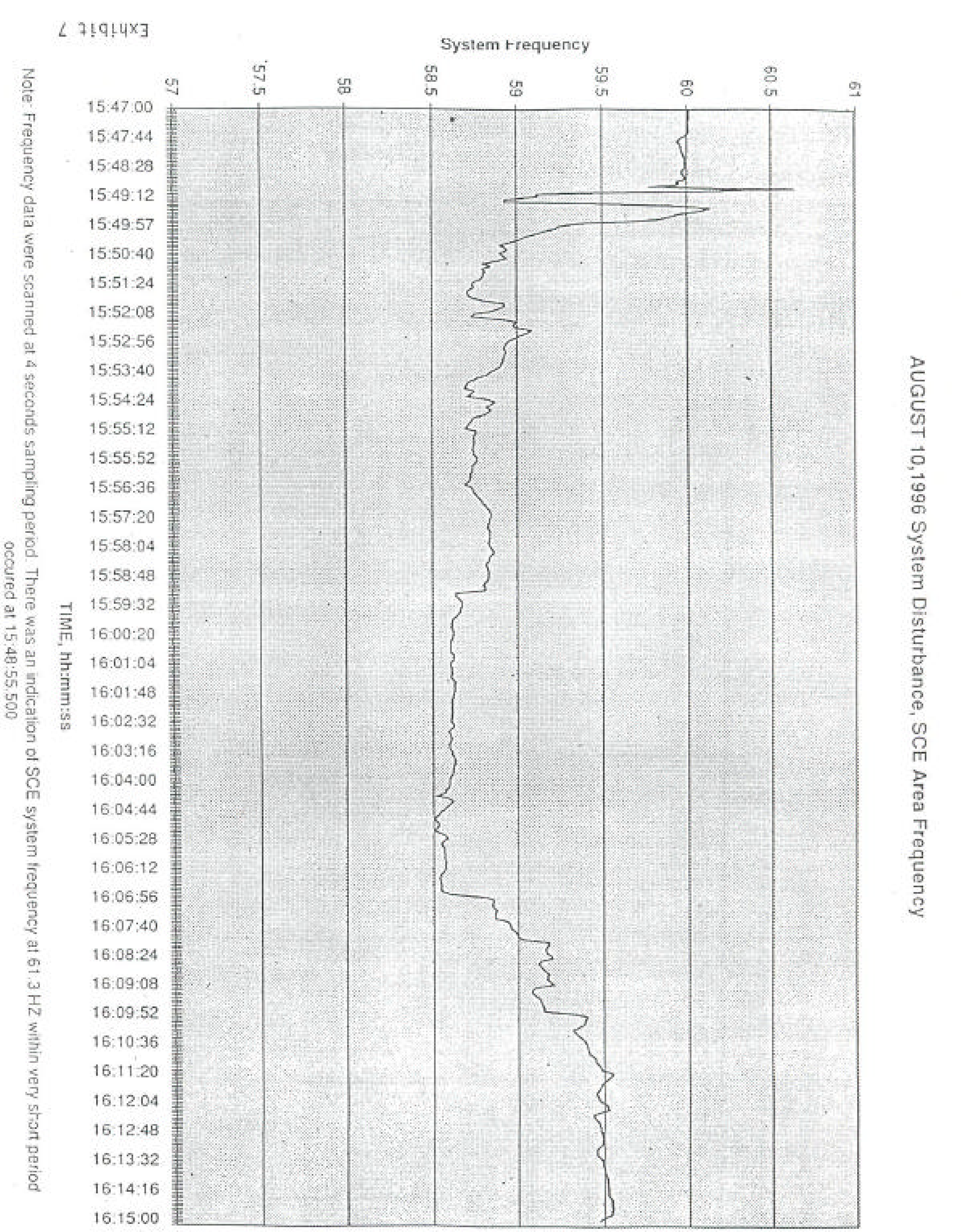


Exhibit 7
AUGUST 10,1996 System Disturbance, SCE Area Frequency
System Frequency
57
57.5
58
58.5
59
59.5
60
60.5
61
15:47:00
15:47:44
15:48:28
15:49:12
15:49:57
15:50:40
15:51:24
15:52:08
15:52:56
15:53:40
15:54:24
15:55:12
15:55:52
15:56:36
15:57:20
15:58:04
15:58:48
15:59:32
16:00:20
16:01:04
16:01:48
16:02:32
16:03:16
16:04:00
16:04:44
16:05:28
16:06:12
16:06:56
16:07:40
16:08:24
16:09:08
16:09:52
16:10:36
16:11:20
16:12:04
16:12:48
16:13:32
16:14:16
16:15:00
TIME, hh:mm:ss
Note: Frequency data were scanned at 4 seconds sampling period. There was an indication of SCE system frequency at 61.3 HZ within very short period occured at 15:48:55.500

Figure 3

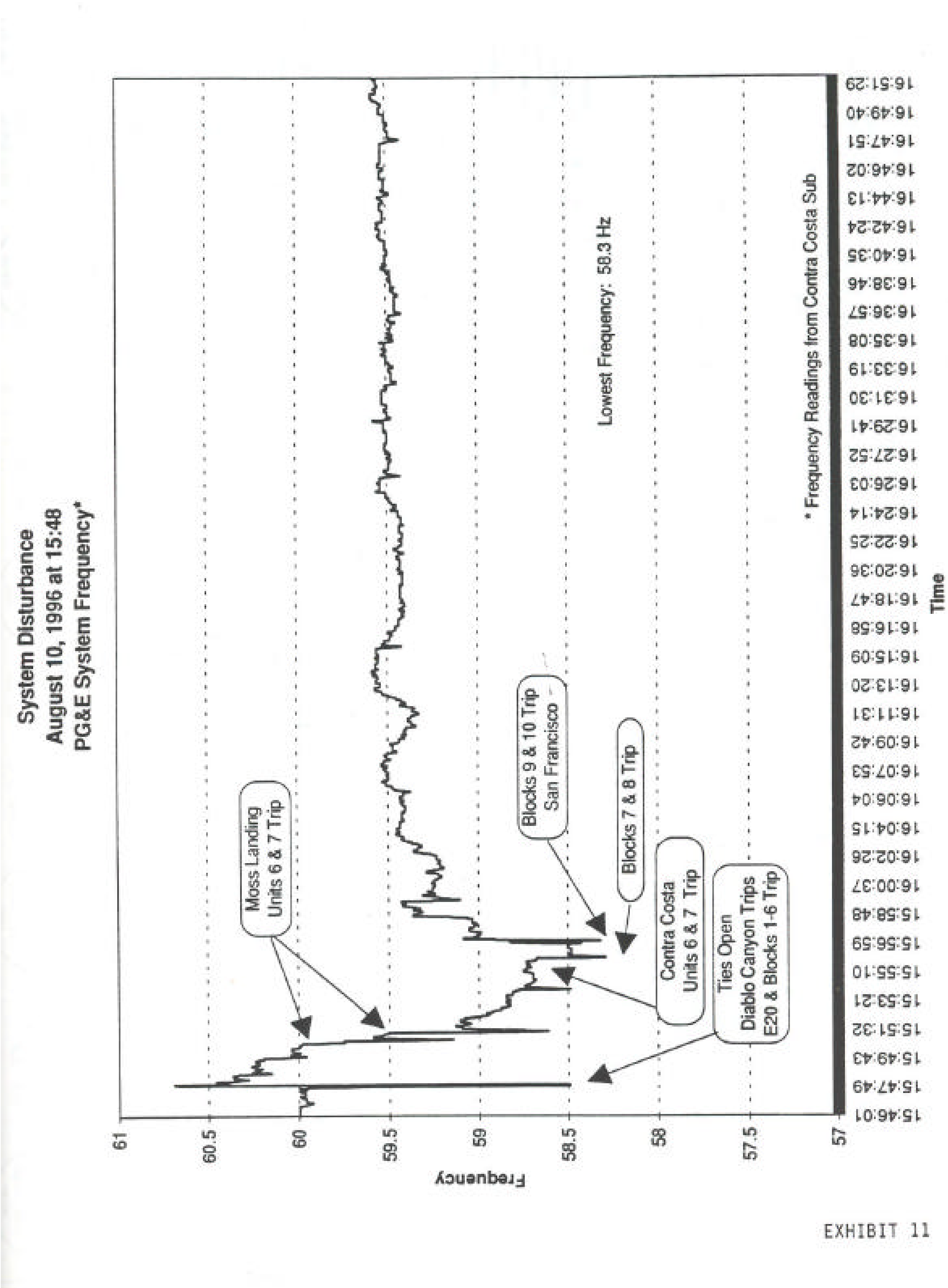

System Disturbance
August 10, 1996 at 15:48
PG&E System Frequency*
Moss Landing
Units 6 & 7 Trip
Blocks 9 & 10 Trip
San Francisco
Blocks 7 & 8 Trip
Contra Costa
Units 6 & 7 Trip
Ties Open
Diablo Canyon Trips
E20 & Blocks 1-6 Trip
Lowest Frequency: 58.3 Hz
* Frequency Readings from Contra Costa Sub
Frequency
Time
61
60.5
60
59.5
59
58.5
58
57.5
57
15:46:01
15:47:49
15:49:43
15:51:32
15:53:21
15:55:10
15:56:59
15:58:48
16:00:37
16:02:26
16:04:15
16:06:04
16:07:53
16:09:42
16:11:31
16:13:20
16:15:09
16:16:58
16:18:47
16:20:36
16:22:25
16:24:14
16:26:03
16:27:52
16:29:41
16:31:30
16:33:19
16:35:08
16:36:57
16:38:46
16:40:35
16:42:24
16:44:13
16:46:02
16:47:51
16:49:40
16:51:29
EXHIBIT 11

Figure 4

Alberta Island

At 1544, about five minutes after the Northern Island separated from the rest of WSCC, the British Columbia Hydro and Power Authority (BCHA) to Alberta interconnections (138 kV and 500 kV) opened, separating the Alberta system from the North Island. At the time of the separation, the Interconnection was supplying 1,230 MW to Alberta. Frequency in the Alberta Island dipped to 59.0 Hz. In this island, 146 MW of generation was removed from service and 968 MW of demand was shed by under frequency load shedding, affecting 192,000 customers. Alberta resynchronized with British Columbia at 1629. Electric service was restored to all customers by 1739.

Contributing Factors

Several factors contributed to the occurrence and severity of this disturbance.

1. High Northwest Transmission Loading

   - The 500 kV and underlying interconnected transmission system from Canada south through Washington and Oregon to California was heavily loaded due to:

   - Relatively high demands, caused by hot weather throughout much of the WSCC Region.

   - Excellent hydroelectric conditions in Canada and the Northwest, leading to high electricity transfers (including large economy transfers) from Canada into the Northwest, and from the Northwest to California. System conditions in the Northwest were similar to the conditions prior to the July 2, 1996 disturbance, except electricity was flowing into the Northwest from Idaho. The excellent hydro conditions allowed exports to California on the COI of up to 4,750 MW, as determined by operating nomogram limits developed by BPA, PG&E, Idaho Power Company, and PacifiCorp following the July 2, 1996 disturbance.

   During these periods of high transmission loading, BPA operators had previously noticed small changes in electricity flows causing large changes in voltage, indicating voltage support problems in the Northwest during stressed operating conditions.

2. Equipment Out of Service

   - In the hours before the disturbance, three lightly loaded 500 kV lines (Big Eddy – Ostrander, John Day – Marion, and Marion – Lane) in the Portland area were forced out of service. These 500 kV lines were providing reactive support for the transmission system. Two of the outages were caused by flashovers (arcs) to trees resulting from inadequate right-of-way maintenance, and one outage resulted from a circuit breaker being out of service.

   - The 115 kV Allston – Rainier line was out of service due to degraded capability of line hardware. The 115 kV Longview – Lexington line was out of service for fiber-optic cable installation. These outages contributed to system stress following the loss of the Keeler – Allston line.

   - A 500 kV circuit breaker at Marion, a 500 kV circuit breaker at Keeler, and the 500/230 kV transformer at Keeler were out of service for modification. The static var compensator (SVC) at Keeler was reduced in its ability to support the 500 kV system voltage due to the transformer outage (the SVC is tied to the 230 kV side). Because Northwest demands are historically lower in the summer than in the winter, BPA performs most system maintenance during the summer.

3. Triggering Events

- The Keeler – Allston line sagged too close to a tree and arced to ground, forcing the 500 kV Pearl – Keeler line out of service. These outages overloaded parallel 230 kV and 115 kV lines in the Portland area, and depressed the 500 kV voltage.

- Five minutes after the above mentioned lines opened, the 115 kV St. Johns – Merwin line opened due to a zone 1 relay malfunction, contributing to the loading of other parallel lines.

- The overloaded 230 kV Ross – Lexington line sagged too close to a tree and arced to ground, resulting in the removal from service of Swift generation, further depressing the system voltage.

- System protection began removing units from service at McNary and increasing power and voltage oscillations began. These oscillations increased until the three 500 kV COI lines opened due to low voltage.

- Some of the electricity that had been flowing on the COI lines surged east and south through other parts of WSCC causing numerous transmission lines to open due to out-of-step conditions and low voltage, creating islands.

4. Key Factors

- BPA's right-of-way maintenance was inadequate. Consequently, BPA's failure to trim trees and remove others identified as a danger to the system caused flashovers from and the opening of several 500 kV transmission lines, the last of which led to overloads and cascading outages throughout the Western Interconnection.

- BPA operators were operating the system such that a single-contingency outage (the Keeler – Allston line) would overload parallel transmission lines. BPA operators were aware that on July 13, the 500 kV Pearl – Keeler line sagged too close to a tree, flashed to ground and opened. The July 13 line opening forced open the Keeler – Allston line at Keeler due to a breaker outage. The outage loaded the parallel 115 kV Longview – Allston No.4 line to 109% of capacity. Additionally, a jumper burned open within two minutes due to failure of conductor hardware that had degraded. The jumper was not loaded above its thermal rating. The two 230 kV Allston – Trojan lines and the 230 kV Ross – Lexington line were loaded to their thermal limits. Loading on other lines also increased substantially. Although the July 13 incident did not lead to cascading outages, it should have served as a warning prior to the August 10 outage and led to further technical analysis.

  BPA operators were unknowingly operating the system in a condition in which the Keeler – Allston line outage would trigger subsequent cascading outages because adequate operating studies had not been conducted. Operating in a condition where cascading outages could occur is a violation of the WSCC Minimum Operating Reliability Criteria.

  In the hour and a half prior to the disturbance, BPA's 500 kV Big Eddy – Ostrander, John Day – Marion and Marion – Lane lines were forced out of service. Although the opening of none of these lines was individually judged crucial by BPA dispatchers, the cumulative impact resulted in a weaker system. BPA dispatchers did not widely communicate these outages to other WSCC members nor did they reduce loadings on lines or adjust local generation as precautionary measures to protect against the weakened state of the system.

BPA notified PGE of maintenance outages in effect, but did not notify other WSCC members. Nor did BPA widely communicate the forced line outages to other WSCC members, precluding them from making system adjustments had they perceived a need to take such action. BPA did not consider these events to be key facility outages for reporting purposes.

- All the units at McNary were removed from service due to exciter protection as units responded to reduced voltage after the Keeler – Allston and subsequent line trips. Even though the loss of McNary units during the July 2 disturbance had demonstrated problems with the excitation systems on these units, this information had not yet been analyzed and factored into studies performed to develop COI/Midpoint – Summer Lake and other operating limits after July 2. Additionally, some other area generators did not respond to support voltage to the extent modeled in studies used by WSCC utilities.

- The Dalles had only five of 22 generating units operating, generating a total of 320 MW, due to spill requirements imposed to protect salmon smolts migrating downstream, significantly diminishing the voltage support available for the transmission system. The effect of this known operating constraint had not been factored into system studies.

- Growing system oscillations resulted in increasing voltage and power swings on the COI, leading to COI instability and separations. The growing oscillations may be attributed to an increased electrical angle between northwest generation and the COI due to:

  - weakening of the transmission system (opening of the 500 kV Keeler – Allston, 230 kV Ross – Lexington, and other lower voltage lines),

  - a shift of generation to Grand Coulee and Chief Joseph following removal from service of the McNary units, and

  - reduced reactive support to the COI resulting from removal from service of the McNary units and nonparticipation of Coyote Springs, and Hermiston, which were operating on constant power factor control rather than voltage control.

  In addition, the response of the PDCI to system voltage swings may have contributed to growing oscillations.

5. Widespread Loss of Generation and Demand

   - The opening of the COI (which also occurred on July 2) resulted in about 28,000 MW of under frequency load shedding and about 20,000 MW of unanticipated generation removed from service in the northern California and southern islands in this disturbance.

In summary, the disturbance could have been avoided in all likelihood, if contingency plans had been adopted to mitigate the effects of the 500 kV Keeler – Allston line outage. Inadequate tree trimming practices, operating studies, and instructions to dispatchers also played a significant role in the disturbance.

Due to the significant nature of this system-wide disturbance, there were 32 conclusions and 100 recommendations, which are included in the final report. DAWG selected four key conclusions and associated recommendations to give the reader a sample of the problems identified.

Conclusions & Recommendations

Conclusions:

1. System operation was not in compliance with the WSCC Minimum Operating Reliability Criteria (MORC) prior to the outage of the 500 kV Keeler – Allston line. Outage of this line precipitated the overloading and opening of parallel lines, voltage drops, the undesirable removal from service of key hydro units, and subsequent increasing oscillations, all of which led to opening the California–Oregon Intertie (COI) and other major lines, and the formation of four islands, causing the widespread uncontrolled outage of generation and interrupting electric service to about 7.5 million customers.

Recommendation:

BPA shall assess why it failed to identify that a 500 kV Keeler – Allston line outage would overload parallel lines, and potentially violate the WSCC MORC. BPA shall immediately implement corrective action as appropriate. BPA's assessment and mitigating actions (e.g., operating procedures, training, studies, etc.) that were or are being taken shall be submitted to WSCC's Compliance Monitoring and Operating Practices Subcommittee (CMOPS).

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 2 — Transmission, B. Voltage and Reactive Control
NERC Operating Policy 4 — System Coordination, A. Monitoring System Conditions
NERC Operating Policy 4 — System Coordination, B. Coordination With Other Systems — Normal Operations
NERC Operating Policy 4 — System Coordination, D. System Protection Coordination
NERC Operating Policy 5 — Emergency Operations, D. Separation from the Interconnection
NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Operating Policy 8 — Operating Personnel and Training, C. Training
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, B. Security
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, C. Coordination
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, D. Protection Systems

Conclusion:

10. The system oscillations increased until voltage finally collapsed on the COI, leading to the COI opening and the subsequent formation of four islands in WSCC. Generating units in the Northwest (such as Hermiston, and Coyote springs) did not respond dynamically or in the steady state with reactive support as predicted in studies. The level of dynamic reactive support from generation at the northern terminus of the COI and PDCI was greatly reduced by fish operation constraints, particularly at The Dalles.

Recommendation:

By November 1997, the WSCC Compliance Work Group (CWG) shall determine what tests should be applied to generating units to determine their steady-state and dynamic-reactive capabilities and provide appropriate guidelines. They shall also determine what unit MVA level must be tested and develop a procedure to ensure uniform testing, including the frequency of testing, and a recommended priority list of units to be tested first. (The CWG work must be completed by November 1, 1996) Generation-owing and operating entities in WSCC shall test, or provide proof of tests on their generating units with capacity of ten MW or greater to determine their steady-state and dynamic-reactive capabilities, adjust study assumptions to match the test results, and report to CMOPS.

Refer to: NERC Operating Policy 1 — Generation Control and Performance, A. Operating Reserve
NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, II. Resources, Guides, A. General

Conclusion:

12. Special operations to protect fish, such as reducing generation and increasing spill at The Dalles, reduced the amount of real power, reactive power, and inertial support provided to the system, and, therefore, adversely impacted system reliability.

Recommendation:

The WSCC Intertie Studies Group (ISG) shall model these special fish-protecting operations in the studies they are conducting to determine the impact on COI transfer capability, paying particular attention to the loss of reactive support due to these operations. The WSCC ISG shall report its findings and recommendations to CMOPS.

Refer to: NERC Operating Policy 2 — Transmission, B. Voltage and Reactive Control
NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Operating Policy 6 — Operations Planning, B. Emergency Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, II. Resources, Guides, A. General

Conclusion:

31. In response to this disturbance, utilities' energy traders, generation operators, and transmission operators found it necessary to coordinate closely to restore the system. As members restructure to comply with FERC Order 889, Standards of Conduct, such close coordination may be limited.

Recommendation:

The WSCC Operating Committee shall assess the potential impact of FERC Order 889 on coordination between generation marketers/owners and transmission operators during disturbances and make appropriate recommendations to improve the coordination of system restoration.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 3 — Interchange, A. Interchange
NERC Operating Policy 5 — Emergency Operations, A. Coordination With Other Systems
NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, C. Coordination

Anyone interested in obtaining a hard copy of this disturbance report is asked to submit in writing a request to the WECC Technical Staff at the Western Electricity Coordinating Council (formerly the Western Systems Coordinating Council) office.

NEW YORK POWER POOL DISTURBANCES — AUGUST 26 AND OCTOBER 30, 1996

Overview

The transmission system in New York State consists of a 345 kV backbone that connects the system from west to east, starting at the 345 kV Niagara station, and the ending in southeastern New York, in the Consolidated Edison Company of New York, Inc. (Con Edison) system. Historically, this system was limited much more frequently by transient stability and voltage collapse considerations than by transmission line thermal capability, or post-contingency thermal limits. A series of transfer interfaces, or "cut-sets," were developed over the years for monitoring the stability and voltage collapse phenomena. Limits for these transfer interfaces were developed off-line and are used in the New York Power Pool's (NYPP's) energy management system to monitor the transmission system. One of these interfaces is the Central–East interface.

The Central–East interface security limits protect the bulk electric transmission system between the Utica area (the southern terminus of the 765 kV interconnection with Hydro-Québec) and the Albany (Capital District) area. This interface is monitored for transient stability and for voltage collapse. Three specific contingencies were identified as having the greatest potential for post-contingency voltage collapse. The security limits on this interface were developed for a number of line outage scenarios; in some outage cases, the transfer limits can be dramatically reduced during a transmission system forced outage.

The two incidents discussed below are similar in that the initial event did not (in itself) cause a problem, because the system was operated within established NERC and NPCC (Northeast Power Coordinating Council) Criteria. In both cases, however, the initial line outages caused significant changes in the Central–East transfer interface flows or limits, and the process of redispatching the system to a secure state to prepare it for the next contingency required drastic action by the system operator, — NYPP Senior Pool Dispatcher.

The sequence of events and operator actions for each of the two disturbances are discussed separately. The conclusions and recommendations apply to both events and are discussed following the incident descriptions.

Loss of the 345 kV Gilboa – Leeds Line — August 26, 1996

Introduction

System protection removed the 345 kV Gilboa – Leeds line from service at 14:39 EDT. Although this contingency did not immediately result in the overload of any bulk electric system facilities, the process of returning the system to a secure state following its removal from service ultimately resulted in an order to shed firm demand in Eastern New York State. A one-line diagram of the eastern New York bulk electric system is shown as Figure 1.

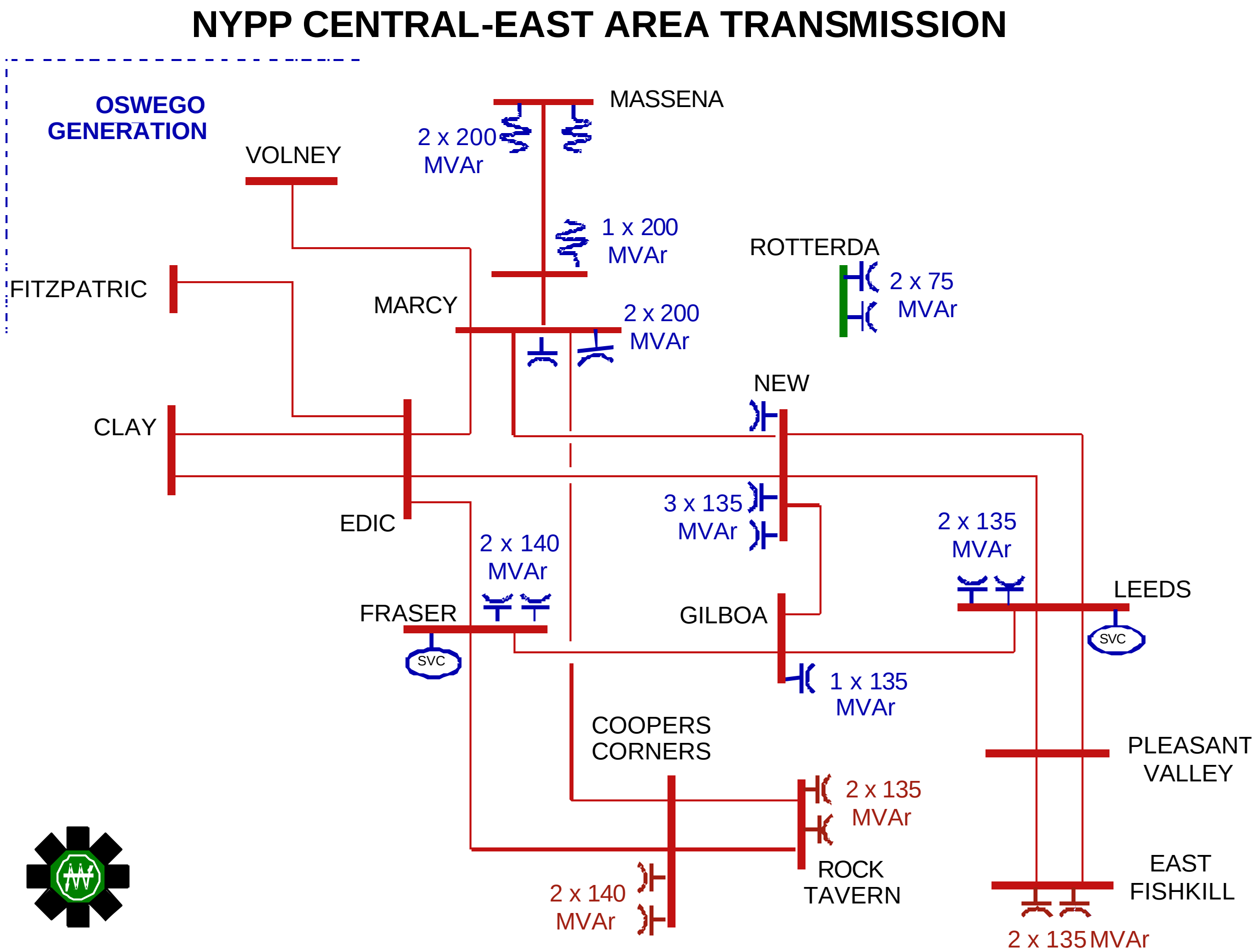


Figure 1

Pre-disturbance conditions

The system conditions just prior to the Gilboa – Leeds outage:

The control area demand was 24,300 MW

- Total Operating Reserve (10-minute and 30-minute reserve requirement) available to the NYPP was 2,610 MW compared to a requirement of 1,671 MW (1,136 MW was located in eastern New York).
- 1,396 MW of 10-minute reserve was available compared to a requirement of 1,114 MW (346 MW located in eastern New York).

Inter-Pool schedules were as follows:

- 1,126 MW net purchase from Hydro-Québec
- 277 MW net purchase from Ontario Hydro
- 300 MW net sale to NEPEX (New England Power Exchange)
- 1,140 MW net sale to PJM (PJM Interconnection Association)

- Prior to the event, at 1413, EDT, system protection removed from service the New England Power Exchange's (NEPEX) Yarmouth unit No.4, (610 MW), and, thus, it limited ability to supply capacity.
- NYPP was operating in the NORMAL state

Description of Incident

At 1439, the 345 kV Gilboa – Leeds circuit opened due to the failure of a capacitor in a relay circuit that was part of the backup protection system for that line. The outage of the line resulted in an increase in flow on the Central–East interface of about 120 MW, such that the transfer interface flow immediately after the line's removal from service was about 2,800 MW.

The NYPP energy management system (EMS) security analysis programs constantly calculate the predicted post-contingency flow on the Central–East interface for the contingencies identified as the worst case with respect to post-contingency voltage collapse at the 345 kV New Scotland station. The calculated post-contingency flow is compared to transfer limits derived from off-line engineering studies that define the transfer level where voltage collapse will not occur. Immediately following the opening of the Gilboa – Leeds line, the NYPP EMS indicated that the post-contingency flow on the Central–East interface was above the voltage collapse limit for the loss of the 345kV New Scotland bus. As a result, the senior pool dispatcher (SPD) declared an ALERT state in accordance with NYPP Operating Policy No.1 (OP No.1). After the NYPP EMS processed the topology change, and recalculated distribution factors, the SPD realized the correct predicted post-contingency flow was actually more than 500 MW above the voltage collapse limit, which results in the immediate declaration of a MAJOR EMERGENCY state, as defined in OP No.1.

OP No.1 requires that a when a security violation of this type occurs, the predicted post-contingency flow must be reduced to below 105% of the limit within 15 minutes, and below the actual limit within 30 minutes after the violation occurs. The declaration of the MAJOR EMERGENCY gives the SPD the authority to take immediate remedial actions, up to and including load shedding to restore the bulk electric system to a secure state and return NYPP to the NORMAL operating state.

Chronology of Events and Operator Actions

1439	Gilboa – Leeds 345kV circuit removed from service. NYPP SPD initiated immediate actions to reduce flow on Central–East interface: Declared ALERT state Reduced energy purchase from Hydro-Québec by 300 MW Requested Long Island Lighting Co. (LILCO) start 300 MW combustion turbines Requested New York Power Authority (NYPA) reduce Gilboa generation by 250 MW
1445	NYPP EMS completed initial assessment of system conditions with Gilboa – Leeds out of service, indicating to the SPD that the calculated post-contingency Central–East flow exceeded the Voltage Collapse limit by more than 5%. SPD declared the MAJOR EMERGENCY state and ordered additional corrective actions: Purchased 300 MW emergency energy from NEPOOL Executed a "Reserve pick-up" dispatch to increase eastern New York generation at emergency response rates (361 MW)
1458	NYPP EMS calculated post-contingency flow on Central–East interface was 2,520MW, about 12% over the limit of 2,250 MW. SPD orders member systems east of Central–East interface to implement "Quick Response Voltage Reduction" (automatic 5% voltage reduction). About 350 MW relief was obtained in nine minutes.
1500	SPD ordered 210 MW additional reduction of Gilboa generation (total 460 MW)

1506 SPD further reduced energy purchase from Hydro-Québec by 400 MW (total reduction of energy purchases from Hydro-Québec was 700 MW)
1510 SPD ordered 250 MW reduction of Gilboa generation (total 710 MW)
1515 The predicted post-contingency flow on Central–East interface was still 90 MW in excess of the required limit. OP No.1 requires that if flows have not been returned below limits within 30 minutes, load relief measures must be taken.. The SPD ordered firm demand shed by systems east of the Central–East interface. In addition to the verbal communication indicating to each member its load reduction requirement via the NYPP "Hot-line" emergency telephone system, the SPD also activated the "load-shed alarm," which gives a visual and annunciator notification in all member system control centers to indicate that a load-shed order was issued. A total of 238 MW of relief was obtained.
1517 Predicted post-contingency flow on the Central–East interface is below limit.
1526 SPD satisfied that OP No.1 criteria were being met and that customer demand could be restored.
1530 5% voltage reduction terminated.

Loss of the 765 kV Chateauguay – Massena – Marcy Line – October 30, 1996

Introduction

At 0637 EDT, system protection removed the 765 kV Chateauguay – Massena, and the Massena – Marcy lines from service during a switching operation to remove Massena shunt reactor No.2 from service. These 765 kV circuits comprise the EHV bulk electric system interconnection between the NYPP system in central New York state and the HVDC facilities at the Chateauguay station in the Hydro-Québec system. Similar to the event of August 26, 1996, this outage resulted in a significant reduction of the Central–East interface voltage collapse limit. Prior to the line opening, the Central–East interface was limited to 2,600 MW. Immediately following the outage of the 765 kV facilities, the projected post-contingency flow limit on the Central–East interface was restricted to 1,840 MW based on the post-contingency voltage collapse. The actual flow on the Central–East interface facilities immediately following the line openings was 2,240 MW.

Pre-disturbance conditions

The event occurred during the morning demand increase when the NYPP system demand was increasing at about 1,500 MW/hr. Just prior to the event, the control area demand (instantaneous) was 15,600 MW. Several adverse conditions occurred during the 20-minutes prior to the contingency:

0619 The SPD declared the ALERT state due to a violation of the Dysinger–East interface transient stability limit.
0628 200 MW purchase by Niagara Mohawk Power Corporation from Ontario Hydro was cut to relieve loading of the Dysinger–East interface.
0630 SPD orders an increase in reserves to assist in following demand increases and replace the 200 MW transaction cut.
0634 Gilboa pump (250 MW) ordered out of service to keep up with the demand increase.

These actions were necessary to maintain the demand/generation balance during the morning demand increase. As a result, the NYPP was operating in the ALERT state. Response to successive reserve increases generally are not as effective as the first one.

Description of Incident

System protection removed from service the 765 kV Chateauguay – Massena and Massena – Marcy lines at 06:37 EST during a switching operation when the system operator was removing the 765 kV Massena No.2

shunt reactor. The actual cause of the trip was a pole-disagreement in the shunt reactor breaker. The outage of these circuits results in a reduction of the Central–East post-contingency voltage limit to 1,840 MW, and the Central–East (pre-contingency) transient stability limit to 2,000 MW. The actual flow on the Central–East interface was 2,240 MW. Because the actual flow exceeded the indicated limits by more than 5%, the SPD declared a MAJOR EMERGENCY state according to OP No.1 and initiated immediate actions to reduce the flow. The opening of the Chateauguay – Massena circuit also caused a curtailment of energy delivery from Hydro-Québec to NYPP.

Chronology of Events and Operator Actions

0637	System protection removed from service the 765kV Chateauguay – Massena and Massena – Marcy circuits. SPD declared a MAJOR EMERGENCY state for the Central–East interface because the stability limit was exceeded by more than 5%.
0638 – 0642	NYPP SPD ordered about 1,350 MW resource and schedule changes in southeastern NY, and reduced western NY generation by 350 MW to reduce flow on the Central–East interface including an increase in reserves to increase generation at emergency response rates for loss of the Hydro-Québec energy delivery.
0645 – 0653	NYPP purchased 300 MW emergency energy from NEPEX. Reduced western generation an additional 450 MW. Requested Ontario Hydro change phase-angle regulator schedules on the 230 kV St. Lawrence – Moses ties.
0654	SPD ordered 5% Quick Response Voltage Reduction in eastern NYPP.
0656 – 0700	SPD ordered additional generation reduction in western NY, and reduced remaining Ontario Hydro to NYPP energy purchases.
0703 – **0710**	SPD ordered tap changes on phase-angle regulators controlling flow on the 500 kV Branchburg – Ramapo circuit (to increase flow toward NYPP by about 120 MW on that circuit) and cut energy schedules from PJM to Con Edison by 300 MW and from PJM to NEPEX by 151 MW.
0725 – **0740**	Requested additional generation increases in eastern NY.
0740	5% voltage reduction terminated. SPD terminated MAJOR EMERGENCY state and returns system to NORMAL state.
0825	NYPA restored 765 kV Massena – Marcy circuit .

Conclusions and Recommendations

Both of these events, while significantly different in initiating event, were very similar in the actions necessary to address the security needs of the system. In each event the contingency resulted in significant reduction in the security operating limits for the Central–East interface, while the flow on the interface did not reduce on the contingency. Reducing the flow on the interface required a major shift of generation in the NYPP system, as well as transaction cuts to further reduce the flow across the interface. Because the flows were more than 5% over the indicated limits, the response (both time and amount) of system resources were critical due to the time limits imposed by OP No.1.

In reviewing these events, the NYPP System Operations Advisory Subcommittee identified several issues that need to be addressed to ensure effective and timely response of system resources during events of this nature:

Effectiveness of Quick Response Voltage Reduction

In both events the member system operators were timely in their implementation of the voltage reduction order, but the actual relief obtained was considerably less than the expected amounts (as forecast by the member systems). In the August 26 event, for example, the expected relief was 766 MW, but only 350 MW was actually obtained. This issue was addressed, and the forecast tables for voltage reduction were revised to reflect actual operating experience.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 2 — Transmission, B. Voltage and Reactive Control
NERC Operating Policy 5 — Emergency Operations, A. Coordination With Other Systems
NERC Operating Policy 6 — Operations Planning, B. Emergency Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy

Generation response

Generation response in these events was slow. In particular, response to requests to reduce generation in western NYPP, compensating for increases in eastern generation, was not satisfactory. The NYPP established a working group to review generation response and identify methods for ensuring that the stated response was achievable at all times. A "Max-Gen Pick-up" requirement had already been implemented in OP No.1. It directed member systems to make available any synchronized generation, including units that were not declared for control or regulation purposes, to be utilized in such emergency situations.

Refer to: NERC Operating Policy 1 — Generation Control and Performance, A. Operating Reserve
NERC Operating Policy 5 — Emergency Operations, A. Coordination With Other Systems
NERC Operating Policy 6 — Operations Planning, B. Emergency Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, II. Resources, Guides, A. General
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, II. Resources, Guides, C. Supply-Side Resources

Locational-Based Reserves and Transmission Contingencies Related to Reserves

These issues were addressed in the NYPP reviews of both events and are closely related. The two events discussed here, as well as other recent system events, indicated that the NYPP EMS needs to be able to identify situations of reserve generation "bottling," where reserve generation response may be limited or unavailable due to system security constraints. The NYPP EMS can identify bottling caused by individual equipment thermal limitations, but did not have the necessary programming to identify a reserve generation response situation caused by transmission interface limitation(s). In both these events, additional reserve generation resources east of the limiting interface were desirable.

The senior pool dispatchers were instructed to monitor generation reserves in eastern NYPP while the necessary procedures and modifications were developed so the NYPP EMS could monitor and identify these situations.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 2 — Transmission, B. Voltage and Reactive Control
NERC Operating Policy 5 — Emergency Operations, C. Transmission Overload
NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, B. Security

Schedule and Control of PARs on Inter-area Ties

When generation was increased in southeastern NYPP, a portion of that generation flowed west into the PJM systems via ties between Con Edison and Public Service Electric & Gas Company; these flows reduced the impact that the generation increases had on the flows on the Central–East interface. These ties are normally controlled by phase-angle-regulating transformers, with tap-positions determined by the interchange schedules.

A joint working group of NYPP and PJM was formed to develop a procedure to allow for coordination of tap-changes on these transformers and produce more effective relief on the Central–East interface. This procedure is now in use.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 2 — Transmission, B. Voltage and Reactive Control
NERC Operating Policy 5 — Emergency Operations, A. Coordination With Other Systems
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, C. Coordination

EMS Computer System Response

During the August 26 event, the EMS model update processes took over five minutes, during which time the Senior Pool Dispatcher did not have a complete picture of the gravity of the situation. The NYPP Information Services staff identified and implemented changes to improve the EMS computer system response and provide the SPD with the necessary information in a timely fashion.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 2 — Transmission, B. Voltage and Reactive Control
NERC Operating Policy 5 — Emergency Operations, C. Transmission Overload

For additional information on these events, please contact the New York ISO (formerly, the New York Power Pool).

Allegheny Power System Disturbance — September 21, 1996

Preliminary Conditions

Allegheny Power System (APS) demand was 4,600 MW with fair weather and temperatures in the 70s. Transactions from ECAR to the Pennsylvania-New Jersey-Maryland Interconnection Association (PJM) totaled 2,348 MW and transactions to Virginia Power (VP) totaled 1,369 MW. APS was purchasing 1,200 MW from the west because several extra-high voltage (EHV) generators were not in service. The 500 kV Yukon – Keystone line was removed from service at 0735 EDT for a planned eight-hour outage to repair a damaged conductor. At the Belmont substation, a 500 kV breaker was out of service for a complete overhaul.

Summary of Events

At 1124, 500 kV breaker BL9 at Belmont failed and initiated a series of events (Figure 1). The 500 kV Harrison – Belmont line was removed from service because the 500 kV BL7 breaker was not in service due to a scheduled overhaul. The initial BL9 breaker failure caused 500 kV breakers BL3, BL6, and BL12, and two 138 kV breakers at Belmont to open, clearing the East 500 kV bus. A flashover relay on breaker BL12 initiated a second breaker failure operation, although the breaker did not have a problem. This operation removed from service the 765 kV Kammer and Mountaineer terminals, the 500 kV Belmont BL10 breaker and the 765/500 kV No.5 transformer high-side air switch. The Kammer and Mountaineer terminals reclosed after the Belmont No.5 bank was cleared. A flashover relay on breaker HL12 at Harrison also initiated a breaker failure operation that cleared the South 500 kV bus. No problem was found and the bus was restored to service at Harrison. In addition to the removal of the 500 kV Harrison – Belmont line, the 765/500 kV Belmont No.5 transformer, and the 500/138 kV Belmont No.3 transformer, primary and backup station service at Belmont was no longer available leaving the 500/138 kV Belmont Nos.1 & 2 transformers without forced cooling.

Both Pleasants units, which were dispatched at 550 MW and 560 MW, were immediately reduced due to overloading of the 500/138 kV Belmont Nos.1 & 2 transformers and 138 kV lines in the Belmont area. The 500 kV Belmont BL9 breaker was reported damaged, making return of the 500 kV Harrison – Belmont impossible. By 1325, the 500/138 kV Belmont No.3 transformer was returned to service, alleviating the overloading on the 500/138 kV Nos.1 & 2 transformers and restoring station service at Belmont.

The American Electric Power Columbus Operations Center (AEP) reported that the 765/500 kV Kammer No.200 transformer had a sudden pressure alarm and was leaking oil at 1349. This transformer is owned by APS but is operated and maintained by AEP. At the time of the initial line and breaker openings, the Kammer No.200 transformer increased in loading from 980 to 1,360 MW, and the 345 kV Sammis – Wylie Ridge tie line between Ohio Edison Company (OE) and APS increased from 1,090 to 1,200 MW. The transformer temperatures were being monitored, and it was decided to leave it in service because removing the Kammer No.200 bank from service would severely overloaded the remaining tie lines from the west to APS. A System wide Severe Condition Alert was declared and efforts were directed at curtailing west to east transfers, eliminating APS purchases from the west, and other means to reduce the345 kV Sammis – Wylie Ridge line flow. OE redispatched about 250 MW of generation away from Sammis and began preparations with Duquesne Light Company (DL) to open the 345 kV Beaver Valley – Sammis line as requested by APS to further reduce the flow.

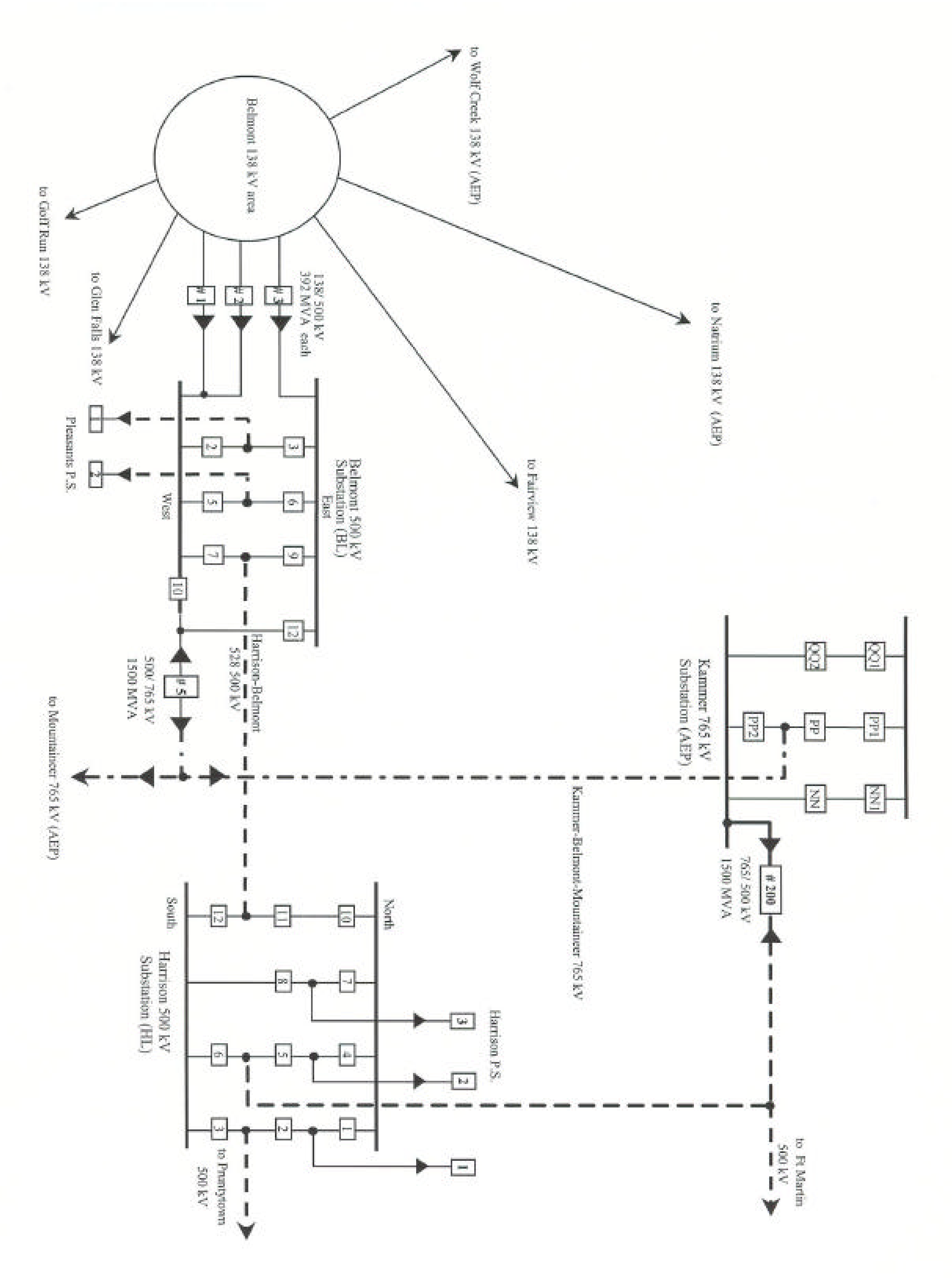

to Wolf Creek 138 kV (AEP)
Belmont 138 kV area
to Golf Run 138 kV
to Glen Falls 138 kV
#1
#2
#3
138/ 500 kV
392 MVA each
to Natrium 138 kV (AEP)
to Fairview 138 kV
Belmont 500 kV
Substation (BL)
East
West
Pleasants P.S.
Harrison-Belmont
528 500 kV
#5
500/ 765 kV
1500 MVA
to Mountaineer 765 kV (AEP)
Kammer 765 kV
Substation (AEP)
QQ1
QQ2
PP1
PP
PP2
NN1
NN
Kammer-Belmont-Mountaineer 765 kV
200
765/ 500 kV
1500 MVA
North
South
Harrison 500 kV
Substation (HL)
Harrison P.S.
to Ft Martin
500 kV
to Pruntytown
500 kV

Figure 1

While switching the 765/500 kV Belmont No.5 transformer back in service, a lightning arrester on the high side of No.5 bank failed at 1418, causing the 765 kV Kammer – Belmont – Mountaineer line to open and lock out of service. In addition to the lightning arrester, one phase of the 765 kV air switch sustained damage.

By 1615, imports were curtailed sufficiently to remove the 765/500kV Kammer No. 200 transformer from service. However, AEP reported that a pressure relief device, which caused the oil leak, reseated and the transformer could be left in service.

System control efforts were refocused on Belmont and the repairs necessary to restore the 765/500 kV Belmont No.5 transformer. A storm front came through the area and at 1725, system protection removed from service one of the 138 kV lines from Belmont. At 1732, the four remaining 138 kV lines opened and Unit No.1 at Pleasants was removed from service on reverse power. This relay operation resulted the islanding of Pleasants unit No.2 and an AMP-OHIO unit at Elkem with about 300 MW of demand.

Pleasants unit No.2, a 626 MW generator, had considerable difficulty controlling frequency in the island. For much of the time, frequency on the island was 61.5 to over 62 Hz and demand was near the unit's minimum operating point with two boiler-feed pumps operating. In an attempt to reduce the frequency, demand was added to the island by separating 138 kV substations from the main bulk electric system and supplying them electricity from the island. About 1900 the AMP-OHIO unit was removed from service due to high frequency. Demand on the Pleasants unit reached about 325 MW but no additional substations could be added to the island. High frequency and instability were both threats to the unit as the demand began to decline through the evening.

The damaged lightning arrester at Belmont was removed to make preparations to parallel the island to the system. Pleasants operators were able to place the turbine control system in manual and throttle steam to reduce frequency long enough to parallel the island to the system.

At 0202 on September 22, the island was paralleled and a black out of the area and the Pleasants station was averted.

Discussion

The initial failure of the 500 kV BL9 breaker became a multiple contingency due to the flashover relay operation from BL12. At Harrison, the 500 kV HL12 breaker had a similar operation although it did not result in the loss of any additional facilities.

It was difficult to determine in the APS Control Area Operations Center that the Pleasants unit had islanded. Three of the 138 kV lines out of the area were removed from service and sectionalized, and then the terminal breakers reclosed. Consequently, on the system board, these lines did not appear open.

The APS control area operators were in communications much of the day with surrounding operation centers. Although there was little time to inform everyone of all the developments, the cooperation of everyone in dealing with APS's requests for transaction curtailments and system reconfiguration was excellent.

Recommendations and Follow-up Actions

1. The breaker flashover relay performance was reviewed for 500 kV breakers. Because of several problems caused by erroneous operations, the protection scheme on all 500 kV line breakers was revised from opening to alarming.

Refer to: NERC Operating Policy 2. — Transmission, A. Transmission Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, D. Protection Systems

2. Input from PJM indicated that a higher level of communications is needed to distinguish between control area and interconnection problems. APS is now the Security Coordinator for eastern ECAR and this communications issue should be satisfied by the new NERC "Hot Line."

Refer to: NERC Operating Policy 7. — Telecommunications, A. Facilities
NERC Operating Policy 7. — Telecommunications, B. System Operator Telecommunications Procedures
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, C. Coordination

3. The operating restrictions for the Pleasants and Willow Island station outputs, when transmission facilities are out of service, was reviewed and updated by APS Network Planning. Control area operator training will emphasize the restrictions under a variety of generation and transmission configurations. Experience gained from frequency control on the island will be incorporated into APS system restoration training.

Refer to: NERC Operating Policy 1. — Generation Control and Performance, A. Operating Reserve
NERC Operating Policy 2. — Transmission, A. Transmission Operations
NERC Operating Policy 6. — Operations Planning, D. System Restoration
NERC Operating Policy 8. — Operating Personnel and Training, C. Training
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, B. Security

4. The feasibility of developing a real-time "loadability" rating system for critical network transformers was under study. A major hurdle to achieving this capability was eliminated with the installation of APS's new EMS in 1997. The new EMS also greatly improved the operators' ability to analyze system conditions during any unusual event.

Refer to: NERC Operating Policy 6. — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, B. Security

5. The station service electricity at Belmont was upgraded to improve reliability.

Refer to: NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, II. Resources, Guides, A. General

For additional information on this event, please contact the East Central Area Reliability Agreement (ECAR) office.

APPENDIX A — REPORTING REQUIREMENTS FOR MAJOR ELECTRIC UTILITY SYSTEM EMERGENCIES

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

1. Loss of Firm System Loads

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

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

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

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

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

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

2. Voltage Reductions or Public Appeals

2.1. A report is required for any anticipated or actual system voltage reductions of three percent or greater for purposes of maintaining the continuity of the bulk electric power supply system.

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

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

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

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

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

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

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

When to Report: The DOE EOC (202-586-8100) shall be promptly notified as soon as practicable after the detection of any actual or suspected acts(s) or event(s) directed at increasing the vulnerability of the bulk electric power system. A 24-hour maximum reporting period is specified in the regulations; however, expeditious reporting, especially of sabotage or suspected sabotage activities, is requested.

4. Fuel Supply Emergencies

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

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

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

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

APPENDIX B — 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 Policies, Procedures, and Principles and Guides for Planning Reliable Bulk Electric Systems*.

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
B. Transfer Capability

Policy 4. System Coordination

A. Monitoring System Conditions
B. Coordination With Other Systems — Normal Operations
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. Operating Personnel and Training

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

Policies, Procedures, and Principles and Guides for Planning Reliable Bulk Electric Systems

I. Forecast
- Principle
- Guides

II. Resources
- Principle
- Guides
  - A. General
  - B. Demand-Side Resources
  - C. Supply-Side Resources

III. Transmission
- Principle
- Guides
  - A. Adequacy
  - B. Security
  - C. Coordination
  - D. Protection Systems

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
03/12/96	**SERC**	**Peninsular Florida**	**INT**	**3,440**	**0**	**Transmission overload**
03/29/96	WSCC	Tucson Electric Power, El Paso Electric, Public Service Co. of New Mexico, Texas-New Mexico Power Co., Comisión Federal de Electricidad, & Plains Electric G&T	INT	1,116	0	Ground fault on 345 kV line
04/15/96	WSCC	PacifiCorp (West)	INT	290	0	Failed 69 kV switch
04/16/96	**SPP**	**Southwestern Public Service Co.**	**INT**	**2,070**	**207,200**	**Bushing flashover during insulator washing**
05/06/96	NPCC	Ontario Hydro	INT	450	39,500	Break in a conductor/phase to ground fault
05/14/96	MAAC	Delmarva Peninsula	INT	819	363,476	Personnel error
05/20/96	NPCC	New York Power Pool	VR	0	0	Lack of operating reserves
05/20/96	NPCC	Connecticut L&P Co., United Illuminating Co., & Connecticut Municipal Electric Energy Coop.	VR	0	0	High temperatures and generation shortage
05/20/96	MAAC	PJM Interconnection Association	VR	0	0	Lack of operating reserves
05/21/96	NPCC	Connecticut L&P Co., United Illuminating Co., Connecticut Municipal Electric Energy Coop.	VR, PA	0	0	High temperatures and generation shortage
05/21/96	NPCC	Consolidated Edison of New York, Inc.	VR, DR	280	113,200	System-wide equipment problems and high temperatures
05/21/96	NPCC	New York Power Pool	VR, PA	0	0	Low operating reserves
06/24/96	WSCC	Idaho Power Company	INT	520	0	Bird in the bus
07/02/96	**WSCC**	**WSCC Interconnection**	**INT**	**2,500**	**1,500,000**	**Unknown**
07/03/96	**WSCC**	**WSCC Interconnection**	**INT**	**1,200**	**0**	**Unknown**
07/06/96	WSCC	Bonneville Power Administration	UO	0	0	Unknown
08/07/96	**ECAR**	**Big Rivers Electric Corporation**	**INT**	**258**	**15,000**	**System operator error**
08/10/96	**WSCC**	**WSCC Interconnection**	**INT**	**0**	**7,500,000**	**Combination of random outages and system oscillations**
08/26/96	**NPCC**	**New York Power Pool**	**VR, DR**	**240**	**0**	**Central-East Interface power flow limitations exceeded**
08/26/96	WSCC	Idaho Power Company	DR	60	8,000	Forest fire and breaker failure

			Firm Load			
09/03/96	WSCC	Public Service Company of New Mexico	INT	118	56,000	Construction bulldozer tore a guy wire
09/05/96	MAPP	Manitoba Hydro	UO	0	0	Suspected tornado
09/21/96	**ECAR**	**Allegheny Power System**	**UO**	**0**	**0**	**Equipment failure**
09/25/96	WSCC	Los Angeles Department of Water & Power & City of Glendale	INT	168	88,000	Ground fault and relay misoperation
10/17/96	MAAC	Potomac Electric Power Company	UO	0	0	Bomb threat
10/21/96	WSCC	Modesto Irrigation District	INT	150	60,000	Disconnect flashover
10/30/96	**NPCC**	**New York Power Pool**	**VR**	**0**	**0**	**Loss of reactor on transmission line**
11/05/96	MAAC	Pennsylvania Power & Light Co.	INT	88	29,000	Procedural error
12/25/96	WSCC	West Kootenay Power, Ltd.	INT	480	75,000	Failure of an aluminum connector on an insulator

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

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