1999
System
Disturbances

Review of Selected
Electric System Disturbances in
North America

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FOREWORD

The Disturbance Analysis Working Group of the North American Electric Reliability Council (NERC) Operating Committee prepared this review of selected 1999 bulk electric system disturbances, unusual occurrences, demand and voltage reductions, and public appeals.

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

- Sharing the experiences and lessons that North American utilities have learned.
- Suggesting ways that utilities can apply the NERC Operating Policies to their operations and the NERC Planning 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

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

NERC's annual review of system disturbance reports begins in November when the Disturbance Analysis Working Group meets to review and discuss each disturbance reported to NERC and DOE so far that year. The Working Group selects reports which they believe to be of value to the industry and then contacts the Regional Council or utility(ies) involved and requests a detailed report of each incident. The Working Group summarizes the report for this review and analyzes it using the NERC Operating Policies and Planning 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 1999, utilities in the United States and Canada reported 36 incidents of system interruptions, demand reductions, voltage reductions, public appeals, or unusual occurrences. These incidents are listed chronologically in **Appendix C** and categorized as:

- Twenty-one system interruptions
- Nine unusual occurrences (no customer interruption)
- Two public appeals
- Two public appeals and interruptions
- One public appeal and voltage reduction
- One public appeal followed by a voltage reduction and interruption

This document contains analyses of four transmission system low-voltage events and an event where high system loading required extensive transmission line loading relief. Unless otherwise noted, 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

Demand Forecasting

The four low-voltage incidents highlight the importance of ensuring demand forecasts are as realistic as possible. In an era where capital investments are closely scrutinized, the possibility exists that forecasts may tend to be conservative, thus, minimizing the need for new construction. However, as the four incidents demonstrate, a period of extreme hot weather can bring demand "out of the woodwork." Forecasters must be continually alert for the possibility of such conditions.

References:

- Low-voltage conditions in ECAR — June 10 and 11
- Low-voltage conditions in MAAC — July 6 and 19
- Low-voltage conditions in Arkansas and Oklahoma — August 13
- Low-voltage conditions in the Atlanta, Georgia area — August 18

Communications

The need for timely, adequate, and effective communications among security coordinators, control centers, Regional Councils, power pools, and other entities having responsibility for system operations during disturbances continues to arise during the analysis of disturbances. This year's review is no different. Although control centers have established communication networks to facilitate communication with other entities, the effectiveness of the communication depends on the operators utilizing the systems.

Communication protocols are necessary to ensure that all participants have the same understanding of the information being exchanged.

Reference:

- Low-voltage conditions in MAAC — July 6 and 19

Planning

System planners and operators need to work together during the design of new facilities and modification of existing facilities. Even more important, they must continually review system disturbances to see if changes are needed to permit operators to more effectively handle disturbances. The four low-voltage incidents demonstrate the need to accurately assess system Mvar requirements and the ability to provide them.

References:

- Low-voltage conditions in ECAR — June 10 and 11
- Low-voltage conditions in MAAC — July 6 and 19
- Low-voltage conditions in Arkansas and Oklahoma — August 13
- Low-voltage conditions in the Atlanta, Georgia area — August 18

Training

Utilities should have a plan for initial and continuing training of those responsible for operating and maintaining electricity systems. That plan should address required knowledge and competencies and how they can be used in real-time operations. In one incident, a root cause analysis of the event determined that training was needed on communications protocols, procedures, and operator responsibilities. Operator training was a factor in other incidents not reported here.

Reference:

- Low-voltage conditions in MAAC — July 6 and 19

Planning and Operating Studies

Planning and operating studies are only as good as the quality and accuracy of the data inputs. In the four low-voltage incidents, the overestimation of system Mvar resources was a major factor. A common problem was the inability of generating units to deliver their rated Mvar capability. Another typical problem was the lack of information on capacitor banks out of service or not connected. As a result, operators, in some cases, were forced to take extreme measures to maintain system security. Utilities should review all their planning and operating study data inputs to ensure that operators have the most up to date and accurate information possible.

References:

- Low-voltage conditions in ECAR — June 10 and 11
- Low-voltage conditions in MAAC — July 6 and 19
- Low-voltage conditions in Arkansas and Oklahoma — August 13
- Low-voltage conditions in the Atlanta, Georgia area — August 18

Operations

The tremendous growth in the number of interchange transactions being scheduled in recent years has placed an ever-increasing burden on system operators and security coordinators. To assist in maintaining system security, NERC has provided security coordinators with the interim Interchange Distribution Calculator, and subsequently, the Interchange Distribution Calculator (IDC). When a transmission line overload occurs, the IDC is queried and the impact on the transmission grid of existing energy transactions is calculated using power transfer distribution factors. Transactions with a 5% or greater impact on the line in question are identified and listed for possible reduction or curtailment. Use of the IDC significantly reduces the time required for corrective action.

Reference:

- System loading conditions in ECAR — August 19–20

DISTURBANCES BY ANALYSIS CATEGORY

Operating Policies

Operating Policies	Incident Number					
	1a	1b	1c	1d	2	
Policy I. Generation Control and Performance						
E. – Control Performance		X				
Policy 2. Transmission						
B. – Voltage and Reactive Control	X	X	X	X		
Policy 4. System Coordination						
A. – Monitoring System Conditions		X				
Policy 5. Emergency Operations						
A. – Coordination with Other Systems		X				
Policy 6. Operations Planning						
B. – Emergency Operations		X				
Policy 7. Telecommunications						
B. – System Operator Telecommunication Procedures		X				
Policy 8. Operating Personnel and Training						
C. – Training		X				

1a — Low-Voltage Conditions in ECAR on June 10 and 11
1b — Low-Voltage Conditions in MAAC on July 6 and 19
1c — Low-Voltage Conditions in Arkansas and Oklahoma on August 13
1d — Low-Voltage Conditions in the Atlanta, Georgia Area on August 18
2 — System Loading Conditions in ECAR on August 19 and 20

Planning Standards

Standards for Planning Reliable Bulk Electric Systems	Incident Number					
	1a	1b	1c	1d	2	
I. System Adequacy and Security						
D. – Voltage Support and Reactive Power	X	X	X	X		
II. System Modeling Data Requirements						
A. – System Data					X	
B. – Generation Equipment	X		X	X		
D. – Forecast and Actual Demands	X	X	X	X		

1a — Low-Voltage Conditions in ECAR on June 10 and 11
1b — Low-Voltage Conditions in MAAC on July 6 and 19
1c — Low-Voltage Conditions in Arkansas and Oklahoma on August 13
1d — Low-Voltage Conditions in the Atlanta, Georgia Area on August 18
2 — System Loading Conditions in ECAR on August 19 and 20

DISTURBANCES

1. Low-Voltage Conditions in the Eastern Interconnection

Summary

During summer 1999, four low transmission voltage events of significance occurred on the Eastern Interconnection. The Disturbance Analysis Working Group reviewed these events and prepared the following reports for them with the assistance of the Regional Reliability Councils. The four incidents were:

- Low-Voltage conditions in ECAR on June 10 and 11,
- Low-Voltage conditions in MAAC on July 6 and 19,
- Low-Voltage conditions in Arkansas and Oklahoma on August 13, and
- Low-Voltage conditions in the Atlanta, Georgia area on August 18.

It is obvious from the fact that the events did occur that systems were not able to adequately identify conditions preceding them in time to take preventative corrective action. Furthermore, it is fundamental to system security and reliability that adequate **reactive** resources as well as real power resources are available in appropriate locations to assure adequate reserves. Several problem areas were apparent from the DAWG review:

- system modeling studies did not have sufficient, and/or accurate data, or failed to take into account enough contingencies,
- customer demand (MW and especially Mvar) under hot weather conditions was underestimated, and
- the ability of generators to deliver reactive support during periods of peak demand was over estimated.

On the positive side, the reviews demonstrated the usefulness and importance of the security coordinator function and transmission loading relief (TLR) process and the benefits of the interim interchange distribution calculator (iIDC) in restoring system conditions.

The failure to anticipate system conditions in each of the events reviewed appears to be due to the inability of system models to accurately predict system conditions, particularly in regard to low-voltage conditions. Predictive capability, in turn, is related to the quantity and accuracy of the input data. With the tremendous increase in transactions and limited system reinforcements under construction or planned, the need for accurate modeling to ensure system security is greater than ever.

NERC Operating Policies, on paper, appear to provide adequate procedures to prevent events such as those studied. Security Coordinator Procedures, Criteria, and Functions are well defined in Policy 9 and Appendix 9D. Policy 2 — “Transmission,” Section B — “Voltage and Reactive Control,” contains explicit requirements for monitoring and controlling voltage and Mvar flows and for providing reactive resources. Appendix 4B — “Electric System Security Data,” lists the data that control areas are to provide to Security Coordinators.

What is not covered in the Operating Manual are criteria for the judgement factors that systems have to use in determining how much data is “enough” and “how good” the data must be. This determination is something that Regions, security coordinators, control areas, and electric utility systems will have to work out among themselves.

Disturbance Analysis Working Group Recommendations

Based on their review of the events, DAWG proposes the following recommendations for Regions, control areas, and systems:

1. Ensure that sufficient data points are being captured to accurately assess system conditions, that real-time data are used in the model to the extent possible, and real system conditions are used to calibrate the models.

2. Consider modeling of system configurations involving multiple contingencies (transmission and generation) to the extent possible.

3. Review demand forecasts in light of the weather and demand conditions experienced in 1999 to ensure that estimates of MW and Mvar demand are realistic and not conservative.

4. Review the ability of generators to deliver reactive support during periods of peak system demand and ensure that generator MW and Mvar capability and output is being provided to Security Coordinators according to Appendix 4B.

5. Review the availability and location of transmission system reactive support in light of higher-than-anticipated reactive power demands experienced during 1999 to comply with the requirements of Policy 2.

6. Review transmission operating guides to ensure that they include procedures, in addition to TLR, to return the system to a secure state.

7. Review transmission reservation procedures to ensure that available transmission capability (ATC) and total transmission capability (TTC) are calculated accurately and updated, as necessary, so that transmission systems are not over subscribed or causing parallel flow problems on neighboring systems.

8. Review the planning criteria for reactive reserve adequacy.

1.a Low-Voltage Conditions in ECAR on June 10 and 11

Summary

During the week of June 7, temperatures in Indiana, Michigan, and Ohio were consistently in the mid 90s. These high temperatures, combined with isolated facility outages, resulted in heavy burdens on the American Electric Power (AEP) transmission system and neighboring transmission providers. On Thursday, June 10, the AEP internal demand peaked at about 19,300 MW and the total demand served by the AEP transmission system was about 31,000 MW. The heavy power flows, together with equipment outages, contributed to low-voltage conditions in central Ohio, with a reading at one location on the 138 kV bus as low as 90% of the nominal voltage. Generally, voltage levels on the 138 kV network were above 95%. The following material provides a recap of the system conditions and corrective actions that were taken Thursday, June 10 and Friday, June 11.

Condition of the EHV System and Adjoining Systems — June 10, 1999

On Thursday, June 10, power flows to the north and west of AEP were heavy throughout the day. Transmission service through AEP was also at a high level. At about 1400 hours EST, power transfers to systems to the north and west were as follows: 2,462 MW to Michigan Electric Coordinated System (MECS), 608 MW to First Energy (FE), and 1,200 MW to ComEd (CE). About this time, a transmission loading relief level 3 (TLR-3) was called by the ECAR/MET Security Coordinator due to low-voltage conditions in central Ohio. The TLR resulted in the curtailment of a 175 MW non-firm AEP-FE transaction and a 308 MW Virginia Power (VP)-CE transaction. AEP internal demand continued to increase, peaking at over 19,300 MW at 1600 EST, while the total demand served from the AEP transmission system declined by about 1,200 MW to about 30,000 MW over the same period. The heavy loadings in northwest Ohio were aggravated by equipment outages outside this area. In First Energy, the Richland-Ridgeville 138 kV circuit (which is north of AEP's Lima service area) and generating units Avon 9 (596 MW) and New Castle 5 (137 MW) were out of service. In Detroit Edison (DE), two of the four 750 MW units at the Monroe Plant (located about 60 miles north of Lima) were out of service.

Within AEP, all major generating units were on-line and generally operating at near capacity, except for the two Cook units (1,020 and 1,090 MW); the EHV transmission network was intact. However, a trip due to a fault of the Canton Central-Cloverdale (AEP-FE) 138 kV circuit and misoperation of the system protection breaker failure scheme resulted in the additional outages of the Tidd-Canton Central (AEP) 345 kV circuit and the Canton Central 345/138 kV transformers. These facilities were all returned to service that evening. In Indiana, AEP had two scheduled outages of 138 kV circuits — the Mullin circuit at Deer Creek for a breaker upgrade, and the Jay circuit at DeSoto for a wave-trap replacement. The Indiana outages had virtually no impact on the conditions in northwest Ohio.

Generally, voltage levels on the 138 kV network were above 95% of nominal voltage. However, the unavailability of the two Cook units, outages at DE's Monroe Plant, and transmission outages near the Lima Area continued to have negative impacts on system voltages.

Conditions of the EHV System and Adjoining Systems — June 11, 1999

All transmission outages in Ohio had been restored the previous evening, June 10. One of Detroit Edison's Monroe units returned to service on the morning of June 11. Due to the improved status of the transmission network, a slight moderation in internal demand, and reduced transfers across AEP's transmission system, there was general improvement in voltages.

On Friday, June 11, power flows to the north and west of AEP were similar to the day before. At 1300 EST, power transfers to the north and west were: 2,548 MW to MECS, 300 MW to FE, and 1,205 MW to CE. About this time, the ECAR/MET Security Coordinator called a TLR-3 on the Dumont 765/345 kV transformer for a contingency loss of the Cook 765/345 kV transformer. The TLR resulted in the curtailment of 306 MW of non-firm transactions to MECS and a 500 MW AEP-CE non-firm transaction. AEP internal demand peaked near 18,600 MW at about 1500 hours, and the total demand served from the AEP transmission system was about 28,000 MW, down about 500 MW from a peak two hours earlier.

Conditions on the Northwest Ohio Area Transmission System — June 10–11, 1999

The northwest Ohio local area transmission system (138 kV and lower) primarily serves demand in the Lima-VanWert-Fostoria-Fremont-Howard areas of the AEP System. The projected area peak demand, for 1999 summer, was 1,650 MW. The area also contains over 550 Mvar of reactive power correction for local area voltage support.

On June 10–11, as the power flows on the overall transmission system increased in order to serve both native demand and the power requirements of neighboring systems, voltages in the area declined. During the morning and evening hours on June 10–11, system voltages of 100% or more of nominal voltage were recorded on the local transmission system. During the same period, voltages on the 345 kV system were about 99% of nominal system voltage. By late afternoon, voltages declined to about 90% at the Howard 138 kV bus and 95–96% at various locations in the Lima area 138 kV system. On the lower-voltage system (below 138 kV) recorded voltages reached about 94%. The Western Transmission Region reported that all critical area station capacitor banks, 34.5 kV through 138 kV, were in service or available to automatically switch into service on June 10 and 11. The Sterling Station 13 kV, 20 Mvar condenser and 34.5 kV, 14.4 Mvar capacitor bank were out of service for a complete replacement of the capacitor bank.

Conclusions

A review of the available data indicates that the reactive power support to the 138 kV system from the 345 kV system was minimal (about 50 Mvar). This low reactive support is a further indication that the sagging EHV system voltage, resulting from contingencies on neighboring systems and heavy power flows on the EHV network, was a major contributor to the lower-area voltages. In addition, on June 10, contingencies on the First Energy system contributed to the low-voltage conditions in Lockwood Road area. Specifically, the outage of a 138 kV circuit into the Richland substation, on the First Energy system, reduced the support to the Lockwood Road area.

On a positive note, the availability of reactive power correction on the local area transmission and distribution systems, coupled with the fact that the taps on the 345/138 kV transformers supplying the local transmission were set to boost 138 kV system voltages, resulted in the 138 kV system voltages remaining higher than the 345 kV system voltages by 3–4%. Area voltages remained above 95% in all but the Fostoria-Howard and Lockwood Road (Mark Center) areas. Although these area voltages fell below 95% on the transmission system, not all customers experienced low-voltage conditions. The majority of the customers are served from AEP's distribution system where the regulation and shunt capacitors are designed to compensate for lower transmission system voltages.

Recommendations

As a result of the high loads experienced in June and later periods in the summer, AEP has decided to add 737 Mvar of shunt reactive support to the transmission system in the Ohio and Eastern Indiana areas to correct the low-voltage conditions and to support additional load growth.

Refer to: NERC Operating Policy 2 — Transmission
- B. Voltage and Reactive Control

NERC Planning Standard I — System Adequacy and Security
- D. Voltage Support and Reactive Power

NERC Planning Standard II — System Modeling Data Requirements
- B. Generation Equipment
- D. Actual and Forecast Demands

For more information on the incident, please contact the East Central Area Reliability Coordination Agreement technical staff.

1.b Low-Voltage Conditions in MAAC on July 6 and 19

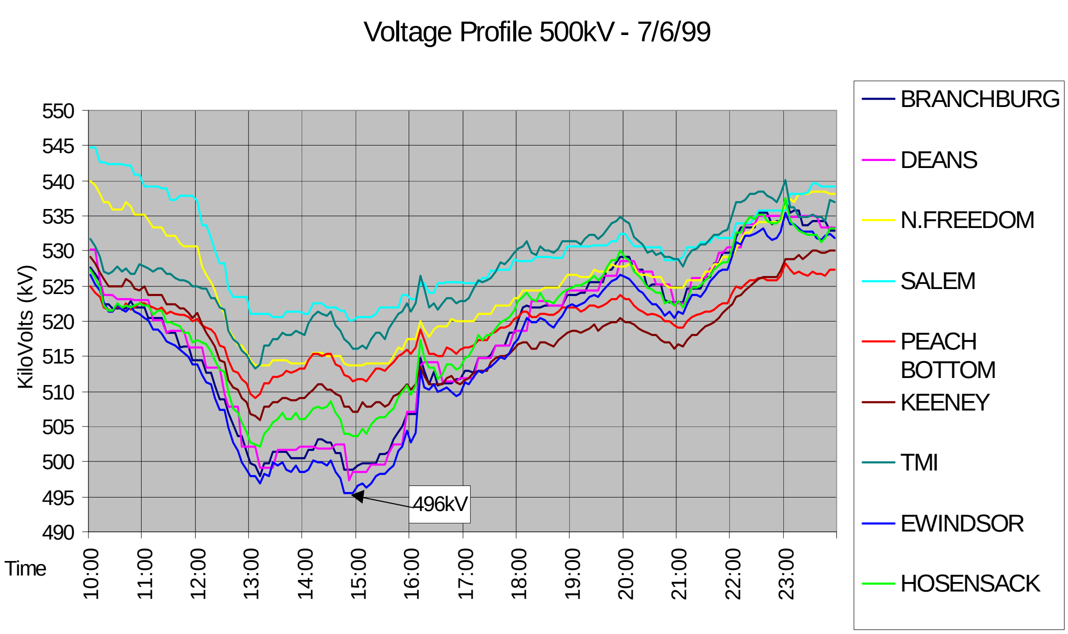
Summary

The MAAC Reliability Assessment for the summer of 1999 indicated that MAAC and all subareas satisfied the system Network Transfer Capability requirements for the system as forecast. However, the assessment indicated that eastern PJM and several subareas possessed limited margin.

System Conditions — July 6, 1999

On July 6, 1999 the MAAC Region experienced sustained Region-wide high temperatures with corresponding high loads. The Temperature Humidity Index (THI) of 85.3 that was observed on July 6, 1999 was very unusual and is estimated to occur only once every 25 years. This record sustained heat resulted in a new peak demand of 51,600 MW (with all load management programs and a 5% voltage reduction in effect) compared to the 1999 forecast peak demand of 47,570 MW (with interruptible load removed). The July 6, 1999 demand of 51,600 MW compares with the forecast peak demand for the summer of the year 2004 (51,603 MW with interruptible load removed).

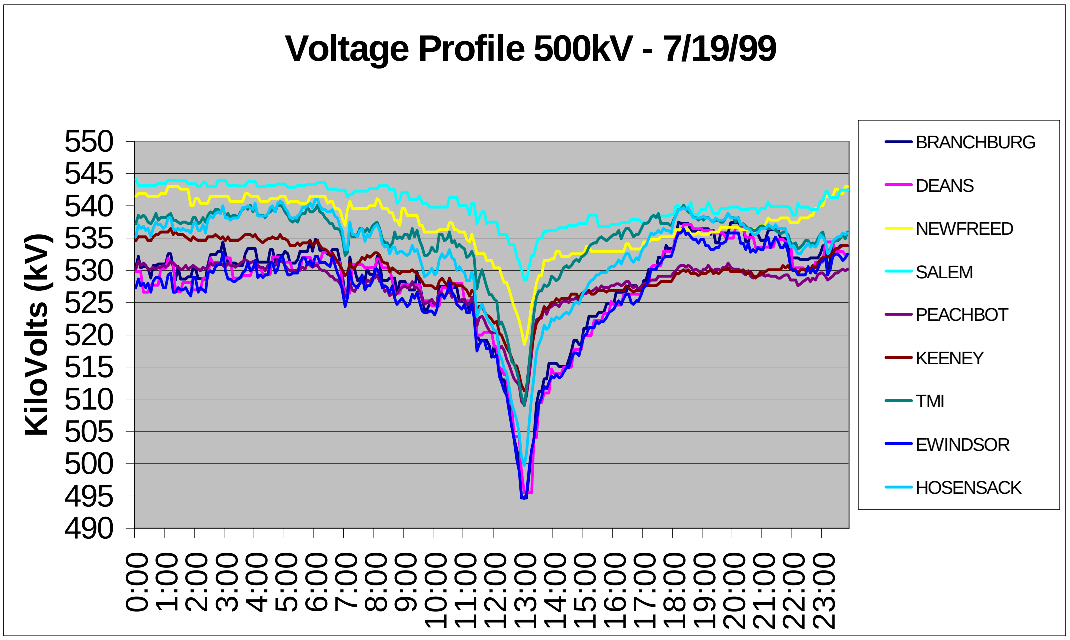
The record high demand was served with the aid of about 6,000 MW of transactions into PJM and the use of PJM emergency procedures which included Load Management, Voluntary Customer Load Curtailment, and a 5% Voltage Reduction. With the high MW and Mvar loads, and increased Mvar losses, the PJM bulk electric system experienced a widespread reduction in system voltage beginning at about noon. Transactions from the systems north of PJM were not possible and additional transactions from ECAR and SERC could not be delivered over the transmission network into eastern PJM due to the low-voltage conditions. After having implemented all its emergency action steps except manual load shedding, and as a last resort, PJM acted to improve the voltage condition by declaring TLR Level 3 to reduce circulation through PJM. An estimated 200 MW of flow was reduced through eastern PJM by curtailing 1,200 MW of transactions.



In addition to the widespread voltage situation on July 6, 1999, several subareas of MAAC, identified in the MAAC Reliability Assessment as possessing limited margin, sustained forced transmission facility outages or disproportionate generation outages resulting in the need for localized load shedding to maintain subarea reliability. Conectiv shed 140 MW of demand to maintain reliability in the Delmarva Peninsula area, and multiple transformer failures at Redbank substation in central New Jersey resulted in about 600 MW of distribution demand being shed.

System Conditions — July 19, 1999

On July 19, 1999, PJM's peak demand exceeded 50,500 MW, and the MAAC Region began experiencing an unexpected rapid decline in the bulk electric system voltage at about noon. PJM loaded all available eastern PJM generation and implemented PJM emergency procedures (all steps of load management and a 5% voltage reduction in eastern PJM) to quickly restore the bulk electric system to the desired level.



Low Voltage — Root Cause Analysis

Initial PJM analysis of the July 6 and July 19 incidents resulted in the discovery that generator Mvar capability used in real-time security analysis and study powerflow analysis was not achievable under the ambient temperature conditions that existed on those dates. Interim Operating Actions were implemented pending a review of all causes of the low-voltage conditions. These interim actions included:

- modifications to the generator reactive capability model to better reflect actual capability experienced on these days,
- the development of an additional voltage interface limit in northeastern PJM to assist in the prediction of voltage problems,
- increased reactive transfer limit safety margin "back-off",
- clarification of the "Heavy Load Voltage Schedule" emergency operations,
- an increase in the use of newly installed EMS advanced application programs, and
- increased staffing at the PJM transmission desk under peak conditions.

PJM initiated a Root Cause Analysis investigation to determine all of the conditions leading to the low-voltage situations, which occurred on both July 6 and July 19, 1999. The Root Cause Analysis identified 25 causes and proposed 20 recommendations, categorized in the following seven areas:

A. Voltage Operating Criteria and Procedures
B. Generation Data and Procedures
C. Planning/Operating Studies and Power System Modeling
D. Energy Management System (EMS) Related Processes
E. Load Power Factor Criteria
F. Communication and Training
G. Energy Market

Refer to:
- NERC Operating Policy 1 — Generation Control and Performance
  - E. Control performance
- NERC Operating Policy 2 — Transmission
  - B. Voltage and Reactive Control
- NERC Operating Policy 4 — System Coordination
  - A. Monitoring System Conditions
- NERC Operating Policy 5 — Emergency Operations
  - A. Coordination with Other Systems
- NERC Operating Policy 6 — Operations Planning
  - B. Emergency Operations
- NERC Operating Policy 7 — Telecommunications
  - B. System Operator Telecommunication Procedures
- NERC Operating Policy 8 — Operator Personnel and Training
  - B. Training
- NERC Planning Standard I — System Adequacy and Security
  - D. Voltage Support and Reactive Power
- NERC Planning Standard II — System Modeling Data Requirements
  - D. Actual and Forecast Demands

For more information on this incident, refer to the PJM report "Heat Wave 1999: July 1999 Low-Voltage Condition Root Cause Analysis" dated March 21, 2000.

1.c Low-Voltage Conditions in Arkansas and Oklahoma on August 13

Summary

On August 13, 1999, at about 1400 CDT, the northwestern part of Arkansas and northeastern part of Oklahoma experienced unusually low voltage on the 115 kV and 161 kV systems. At the time, Entergy Electric System (EES) was seeking voltage/var support for the area. The SPP Security Working Group (SWG) requested an analysis of the situation. Data collection surveys were sent to eight SPP control areas — Central Louisiana Electric Company (CLEC), Central and Southwest (CSWS), Grand River Dam Authority (GRDA), Kansas City Power & Light (KCPL), Oklahoma Gas and Electric (OKGE), Southwestern Power Administration (SPA), Southwest Public Service (SPS), and Western Resources (WR), and four neighboring Regional control areas — Associated Electric Cooperative (AECI), Ameren (AMRN), Entergy (EES), and Tennessee Valley Authority (TVA). The survey requested schedules and interchange information, load values, line and generator status details, generation MW and Mvars, capacitor and reactor status details, bus voltages (especially those with low voltages), and tie-line flows and flowgate flows. Data provided by the responding utilities were included in the model to complete the analysis. The following material provides a recap of the system conditions and results of simulation analysis of the event.

System Conditions on August 13, 1999

There were low voltages in two distinct areas: in the area bordering northwest Arkansas and southwest Missouri and in the area bordering northwest Arkansas and northeast Oklahoma. Low voltages were reported on the 161 kV system in northern Arkansas ranging from 147.7 kV to 157 kV. At Fort Smith, Arkansas, the 345 kV bus voltage was 329.5 kV. The flow on the Arkansas Nuclear One (ANO) — Ft. Smith 500 kV line is typically from ANO to Ft. Smith, but at 1400 CDT, the flow was about 400 MW in the opposite direction.

A review of all the system data indicated that significant transfers were occurring from Western Resources, MAPP control areas (Omaha Public Power District, Nebraska Public Power District, and others), AECI, and AMRN to EES and TVA (some of which was continuing on to Southern Company (SOCO) and Florida control areas). The composite transfer from MAPP, MAIN, and SPP control areas to the EES, SOCO, and TVA combination was about 3,000 MW. The schedules from WR to EES were close to 1,000 MW (this included 325 MW from WR generators and the remaining from MAPP and other control areas). There was about 1,000 MW scheduled to TVA (785 MW from AMRN and 153 MW from AECI). And, there was about 1,000 MW (net) scheduled from TVA to EES (actual TVA to EES schedules of 1,663 MW with EES delivering 633 MW to SOCO). TVA also had 1,633 MW scheduled to SOCO. EES normally sells over 1,000 MW to AECI during summer peak conditions. But at 1400 hours on August 13, 1999, EES had only a 20 MW net schedule going to AECI.

EES had outages of its White Bluff unit 2 (844 MW) and Independence unit 1 (836 MW), both located in northern Arkansas. If Independence unit l and White Bluff unit 2 had been available, their outputs would have resulted in a displacement of power and would have resulted in a totally different set of system conditions. Independence unit 1 was synchronized onto the system at 1336 hours and was at full load by the time of the peak, around 1700 hours. The availability of this generation provided reactive support and reduced the level of imports. At the time of the system peak, system conditions were improving and returning to a state of normalcy.

With a 2–3 day build-up of daily high temperatures and high humidity over the period, the Oklahoma and Arkansas areas experienced near peak load demands on August 12 and again on August 13. The survey data indicated that some of the substations in northern Arkansas had real power demands that were significantly higher than typical summer demands. This resulted in increased reactive requirements for the area.

Unfortunately, the survey data lacked operating data detail that could be used to determine power factors at the individual substations. Lacking this operating data detail, it is impossible to identify one or two substations, or a group of substations, where high reactive demand combined with a lack of local voltage support (from generators, transmission capacitors, and distribution capacitors) can be used to explain a localized voltage problem. It is probably safe to say that although high reactive demand was not the only contributor to the voltage problems on August 13, when this factor is combined with the several other factors described in this report, they all contributed to the voltage problems that day.

Simulation Analysis

SPP utilized the data provided by the various systems to create a power flow case that simulated system conditions for 1400 CDT on August 13, 1999. Even though there wasn't sufficient recorded information on generator voltage readings and reactive generation on that day, the model was able to simulate some of the low voltages experienced in the area bordering northwest Arkansas and southwest Missouri.

Low voltages could not be simulated at Van Buren and Branch areas (the area bordering northwest Arkansas and northeast Oklahoma) using the data provided. The power flow model produced a 97% voltage at Van Buren, VBI, Third Street, and Ft. Smith. Not being able to duplicate low-voltage conditions using a power flow model is a common industry problem. The power flow model tends to overstate voltage conditions because it assumes all units are committed and supplying reactive support during the peak demand, and it assumes the units that are running can produce Mvars at their capability limit.

SPP made several sensitivity runs to evaluate the isolated effects of a transmission line maintenance project, having two EES generators off-line and the high imports into the EES, TVA, and SOCO control areas with the following results.

- The outage of a section of the Danville-Hot Springs 115 kV line reported by EES did not result in low voltages in the model.

- The effect of having Independence unit 1 and White Bluff unit 2 on for voltage support was analyzed by bringing these units on while backing down generators in the south Louisiana area. This scenario simulated a condition where the coal-fired units were on for only voltage support without any impact on the high imports into EES. The analysis found that by just bringing the units on, and not doing anything to imports, the voltages in the Harrison and Branson areas improved only 0.3 to 0.5% and there was no significant improvement to the voltages in the Van Buren and Branch areas.

- By reducing EES imports by 1,300 MW with Independence unit 1 and White Bluff unit 2 off, the voltages in the Harrison and Branson areas improved by 3 to 4%. If both the imports were cut and the units were brought on, the simulated voltages returned to near normal conditions.

Conclusion

Low-voltage conditions in northwest Arkansas and northeast Oklahoma were caused by a combination of generators being off in the EES system, high transfers to EES, TVA, and SOCO (some of which made up for the EES lost generation), and a number of local conditions. The local conditions included:

- Systems being close to their near-peak demands with high reactive demands to serve native loads.
- Apparent lack of local voltage support from generators, transmission capacitors, and distribution capacitors.

Recommendations

SPP will continue to investigate August 13 conditions to see whether a voltage collapse situation would have occurred after loss of another transmission line or a generator. Measures to avoid similar conditions occurring in the future need to be analyzed, developed, and implemented prior to April 2000.

Refer to: NERC Operating Policy 2 — Transmission
B. Voltage and Reactive Control
NERC Planning Standard I — System Adequacy and Security
D. Voltage Support and Reactive Power
NERC Planning Standard II — System Modeling Data Requirements
B. Generation Equipment
D. Actual and Forecast Demands

For more information on the incident, please contact the Southwest Power Pool technical staff.

1.d Low-Voltage Conditions in the Atlanta, Georgia Area on August 18

Summary

On the afternoon of August 18, 1999, the northwest Georgia area experienced low-voltage conditions on the transmission grid. The event occurred during hot weather with a Southern Company control area peak demand of about 39,000 MW. Low-voltage conditions started to occur at about 1300 CDT; system peak occurred about 1500 CDT. The 115 kV system voltage in the Metro Atlanta area was near 109 kV; at Nelson substation, a bus voltage of 104 kV was recorded.

System Conditions

The following generators were out of service at the time: McDonough unit 2 (250 MW), Atkinson unit 2 (60 MW), Buford Hydro (105 MW), and Allatoona Hydro (80 MW). Additionally, Atkinson unit 3 (65 MW) and Wansley units 1 and 2 (860 MW each) had degraded reactive capability. All Metro Atlanta area shunt capacitors were on line. There were no unusual transmission equipment outages at the time.

Energy flows in the Southern Company control area to serve native load and support energy transactions were significant. The system was well beyond the Transmission Planning criteria of loss of any two (2) generating units, with the implied assumption that all remaining units can produce their design Mvar capacity. Because the actual conditions were beyond Transmission Planning criteria, prior system modeling studies had not predicted the low-voltage conditions that occurred. Subsequent system modeling with actual reactive data produced results in close agreement with conditions experienced on the 18th.

Most of the neighboring utilities were also experiencing low voltages. During the event, no customers were interrupted and no reports of customer problems were noted. Subsequent modeling studies indicated selected contingencies could have produced severe operating problems in north Georgia. The total amount of transmission voltage shunt capacitors in the Northern Georgia area is about 5,600 Mvar, all of which are key to the voltage sensitivity of the Atlanta area. When 200 Mvar of shunt capacitors were removed from the system, some load flow models failed to solve.

Conclusions

- Reactive loads in the Metro Atlanta area are greater than forecast.
- The Metro Atlanta region demand to generation mix is such that MW imports to the region are required. Because the import of Mvars is more difficult to achieve (as it is basically limited by voltage level regulation), local sources of Mvars are important to the Metro Atlanta region.
- Several hundred Mvar of fixed capacitors were added to the system in the form of transmission capacitor banks since the summer of 1998. These capacitors were crucial to the system during this event.

Recommendations

- Generation var limits in the Transmission Planning model are to be reviewed by Planning, Operations, and Generation Field Services personnel to ensure their accuracy in the planning models.
- Planning for hot weather scenarios should be made assuming higher reactive demands than have been previously forecast.
- Maintaining voltage schedules at generating plants must continue to be emphasized.
- Consider trading "MWs for Mvars" policy.

Refer to: NERC Operating Policy 2 — Transmission
B. Voltage and Reactive Control
NERC Planning Standard I — System Adequacy and Security
D. Voltage Support and Reactive Power
NERC Planning Standard II — System Modeling Data Requirements
B. Generation Equipment
D. Actual and Forecast Demands

For more information on the incident, please contact the Southeastern Electric Reliability Council technical staff.

2. System Loading Conditions in ECAR on August 19–20, 1999

Summary

On August 19–20, 1999, the temperatures throughout the northern portion of the Eastern Interconnection were in the 80s, while temperatures throughout the southern portion were in the 90s and 100s. Consequently, there were many interchange transactions scheduled from the north to the south, which resulted in high transmission system loadings. The weather pattern and heavy north-to-south flow conditions experienced in ECAR on August 19 and 20 were similar to those that occurred on July 23, 1993 — an incident that was investigated and written up in the 1993 NERC System Disturbances Report. In both incidents, line loading relief was utilized extensively to maintain system security.

Concerns have been raised regarding why, if the incident was addressed in 1993, did it happen again? In all likelihood, it should not have.

Findings

After the investigation of the July 23, 1993 event was completed, ECAR, MAIN, and TVA realized that the problem was caused by too many transfers from ECAR and MAIN to TVA and south of TVA. ECAR, MAIN, and TVA had many discussions concerning this problem and developed a MET (MAIN, ECAR, TVA) procedure to prevent future occurrences. This procedure established methods for coordinating transfers from ECAR and MAIN to TVA and south of TVA to a level that the interconnected network could handle. A special computer system was installed to implement the new MET procedure and to facilitate the exchange of information between the MET participants.

Following the 1993 incident, coordinated MET system seasonal studies were performed annually. These studies were eventually replaced by an on-line system analysis program. The on-line load flow program runs automatically every 20 minutes and covers the ECAR/MET control areas. The program can also be run at any time by the security coordinators for special case analysis. As the real-time ISN data becomes available, it is being fed into the load flow program, which makes the program more accurate. The on-line load flow program gives more accurate results for actual existing system conditions than the old seasonal studies could provide.

With the establishment of the NERC TLR procedures and the NERC security coordinator positions, expectations existed for the new security coordinators to be able to monitor the interconnected system conditions sufficiently to prevent a recurrence of the 1993 incident. After all, the problem had not recurred in six years. However, as the August incident demonstrated, this expectation was not justified. After the event, the parties recognized a need to improve the quality of information being analyzed. After reviewing the August 19–20 event, the AEP Security Coordinator and the associated control areas began identifying the need for additional monitoring points on the affected systems to increase the amount of information reported to the monitoring system.

The August incident did, however, provide a good example of the ability of security coordinators, using the recently established interim Interchange Distribution Calculator (iIDC), to respond to system problems. When the security coordinators analyzed the August 19, 1999 event using the iIDC, the analysis indicated that no transactions contributed 5% or more to line loadings on the Kentucky Utilities, Louisville Gas & Electric, or Big Rivers systems. The loading on these systems was caused by transactions whose parallel path flows contributed less than 5% of the line loading. Corrective action taken for August 20, 1999 was to reduce the available transfer capacity from AEP to TVA and to coordinate all transfers with MAIN. On-line load flows were run to verify the desired results. By contrast, it took ECAR several months to unwind the transactions which contributed to the 1993 incident.

Refer to: NERC Planning Standard II — System Modeling Data Requirements
A. System Data

For more information on the incident, please contact the East Central Area Reliability Coordination Agreement technical staff.

APPENDICES

Appendix A. Reporting Requirements for Major Electric Utility System Emergencies

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

Operating Policy 5F — Disturbance Reporting

Introduction

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

Requirements

1. **Regional Council Reporting Procedures.** Each Regional Council shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.
2. **Analyzing disturbances.** Bulk system disturbances shall be promptly analyzed by the affected systems.
3. **Disturbance reports.** Based on the NERC and DOE disturbance reporting requirements, those systems responsible for investigating the incident shall provide a preliminary written report to their Regional Council and NERC.
   - 3.1. **Preliminary written reports.** Either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Preliminary Disturbance Report form shall be submitted by the affected system(s) within 24 hours of the disturbance or unusual occurrence. Certain events (e.g. near misses) may not be identified until some time after they occur. Events such as these should be reported within 24 hours of being recognized.
   - 3.2. **Preliminary reporting during adverse conditions.** Under certain adverse conditions, e.g. severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Preliminary Disturbance Report within 24 hours. In such cases, the affected entity(ies) shall notify its Regional Council(s) and NERC promptly and verbally provide as much information as is available at that time. The affected utility(s) shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.

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

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

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

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

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

NERC Disturbance Reporting Requirements

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

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

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

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

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

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

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

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

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

6. Any system operation or operator action resulting in:

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

    6.2. major damage to power system components, or

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

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

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

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

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

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

NERC Preliminary Disturbance Report

1. Organization filing report: ______________________________

2. Name of person filing report: ______________________________

3. Telephone number: (   )   -

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

5. Did disturbance originate in your system?

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

7. List generation tripped: MW total
____
____

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

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

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

		Initial	Final
11.	Restoration time		
	Transmission	________	______
	Generation	________	______
	Demand	________	______

U.S. Department of Energy Disturbance Reporting Requirements

Introduction

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

1. Loss of Firm System Loads

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

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

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

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

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

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

2. Voltage Reductions and Public Appeals

2.1. A report is required for any anticipated or actual system voltage reduction of three 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 Standards.

Operating Policies

Policy I. Generation Control and Performance

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

Policy 2. Transmission

A. Transmission Operations
B. Voltage and Reactive Control

Policy 3. Interchange

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

Policy 4. System Coordination

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

Policy 5. Emergency Operations

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

Policy 6. Operations Planning

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

Policy 7. Telecommunications

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

Policy 8. Operator Personnel and Training

A. Responsibility and Authority
B. Training
C. Certification

Policy 9. Security Coordinator Procedures

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

Planning Standards

I. System Adequacy and Security

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

II. System Modeling Data Requirements

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

III. System Protection and Control

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

IV. System Restoration

A. System Blackstart Capability
B. Automatic Restoration of Load

Appendix C. Interruptions, Voltage Reductions, Public Appeals, and Unusual Occurrences

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

			Firm Load			
Date	**Region**	**Utilities**	**Type***	**MW**	**Customers**	**Cause**
01/02/99	SERC	Duke Energy	INT	8–900	240,000	Weather — ice storm
01/14/99	MAAC	Potomac Electric Power Co., Virginia Power, Baltimore Gas & Electric Co.	INT	900	870,00	Weather — ice storm
01/17/99	SERC	Tennessee Valley Authority	INT	N/A	50,000	Weather — tornadoes & wind
01/17/99	MAAC	Potomac Electric Power Co.	INT	90	70,000	Circuit breaker failure
01/29/99	SPP	New Century Energies (Southwestern Public Service Co.)	INT	N/A	50,000	Weather — snow and ice storm
02/11/99	NPCC-Ontario	Ontario Hydro	UO	0	0	Weather — lightning
03/04/99	NPCC-Ontario	Ontario Hydro	INT	640	N/A	Weather — high winds
03/03/99	WSCC	California Oregon Intertie	UO	0	0	Maintenance
03/17/99	MAPP	MidAmerican Energy Co.	INT	60	18,000	Equipment failure
03/31/99	MAPP	Minnesota Power, Minnkota Power Cooperative Inc.	UO	0	0	Outdated operating guide
05/03/99	NPCC-Ontario	Independent Electricity Market Operator	UO	0	0	Equipment failure
05/03/99	SPP	Western Resources Inc.	INT	300	51,000	Weather — thunderstorms
05/10/99	ERCOT	Reliant Energy (Houston Lighting & Power Co.)	INT	1,400	677,000	Weather — thunderstorms
05/17/99	ECAR	Consumers Energy Co.	INT	150	145,000	Weather — thunderstorms
06/07/99	NPCC	ISO New England, Central Hudson Gas & Electric Co., NY Power Pool, Consolidated Edison Co. of NY	PA/VR	N/A	N/A	Hot weather and high customer demand
06/10–11/99	**ECAR**	**AEP, First Energy, MECS**	**UO**	**0**	**0**	**Hot weather, equipment outages, low reactive support**
06/17/99	WSCC	British Columbia Hydro & Power Authority, Alberta Power Ltd.	INT	300	N/A	Weather — lightning
07/05–09/99	**MAAC, NPCC**	**NPCC, PJM, GPU, and Conectiv in MAAC**	**PA/VR/ INT**	**N/A**	**N/A**	**Hot weather, high customer demand, low reactive support**
07/19/99	**MAAC**	**PJM, GPU, and Conectiv in MAAC**	**PA/VR**	**N/A**	**N/A**	**Hot weather, high customer demand, low reactive support**
07/19/99	NPCC - NYPP	All utilities in the NY Power Pool	PA	N/A	N/A	High customer demand
07/23/99	SERC	Entergy	PA/INT	900	557,354	Loss of generation
07/23/99	MAIN	Alliant Energy Corp.	PA/INT	125	68	High customer demand and loss of generation
07/23/99	ECAR	Detroit Edison Co.	INT	1,700	219,000	Weather — thunderstorms
07/26/99	ECAR, SERC, NPCC-NYPP	American Electric Power, Cinergy Corp., Detroit Edison Co., Entergy, KeySpan Corp.	PA	N/A	N/A	Hot weather and high customer demand
07/31/99	ECAR	Detroit Edison Co.	INT	2,000	191,000	Weather — thunderstorms
08/12/99	MAIN	ComEd	INT	110	2,900	Equipment failure
08/13/99	**SPP**	**Entergy**	**UO**	**0**	**0**	**Hot weather, high customer demand, low reactive support, equipment outages**

			Firm Load			
Date	**Region**	**Utilities**	**Type***	**MW**	**Customers**	**Cause**
08/18/99	**SERC**	**Georgia Power Co.**	**UO**	**0**	**0**	**Hot weather, high customer demand, low reactive support**
08/19–20/99	**ECAR**	**ECAR, MAIN, & TVA Subregion of SERC**	**UO**	**0**	**0**	**Hot weather, high customer demand**
08/24/99	WSCC	New Century Energies (Public Service Company of Colorado)	INT	425	163,000	Equipment failure
08/31/99	WSCC	Pacific Gas & Electric Co.	INT	470	257,718	Equipment failure
08/31/99	NPCC	TransEnergie	INT	698	N/A	Equipment failure
08/31/99	ERCOT	Reliant Energy (Houston Lighting & Power Co.)	INT	N/A	176,000	Weather — thunderstorms
09/14/99	FRCC, SERC, NPCC-NY	Florida Power & Light Co., South Carolina Electric & Gas Co., Carolina Power & Light Co., Virginia Power, Orange & Rockland Utilities Inc.	INT	1,000s	over one million	Weather — hurricane
10/09/99	NPCC-New England	ISO New England	UO	0	0	Equipment failure
10/14/99	WSCC	British Columbia Hydro & Power Authority	UO	0	0	Equipment failure
10/15/99	FRCC	Florida Power & Light Co.	INT	130	over one million	Weather — hurricane
11/23/99	NPCC	TransEnergie	UO	0	0	Operator error
12/2/99	NPCC	TransEnergie	INT	44	One	Operator error
12/6/99	MAPP	Manitoba Hydro	UO	0	0	Equipment failure
12/25/99	WSCC	Arizona Public Service Co.	UO	0	0	Equipment failure

*INT = Customer Interruption, VR = Voltage Reduction, PA = Public Appeal, and UO = Unusual Occurrences

N/A = Not Available

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