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EVALUATION OF THE RELIABILITY OF THE OFFSITE POWER SUPPLY AS A CONTRIBUTOR TO RISK OF NUCLEAR PLANTS

Final Report for JCN J2528

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Abstract

The objective of this project (job code number J2528) is to provide technical expertise from the Oak Ridge National Laboratory (ORNL) to assist the Nuclear Regulatory Commission (NRC) staff assessing the nature of any changes in the reliability of the national electric power grid to supply offsite power to nuclear power plants due to electric industry restructuring. Specifically, the task is to determine the potential for increases in the frequency of loss-of-offsite power (LOOP) events associated with grid-related offsite power events.

NRC is responsible for the evaluation of issues related to the design and operation of offsite power grid systems with regard to interrelationships between the nuclear unit, the utility grid and interconnecting grids, the functional performance, design and operation of on-site power systems, and the interface between the offsite and on-site power systems to include performance-related issues for electrical components.

Safe nuclear plant operation requires a source of power capable of maintaining acceptable static and dynamic voltage and frequency limits while supplying minimum amounts of auxiliary power. The preferred power source for safe plant operation is the offsite electric power system or power grid.

Accident sequences initiated by LOOP are important contributors to risk for most nuclear plants. In 1979, the NRC identified the loss of all alternating current (AC) electrical power to the nuclear plant, called station blackout (SBO), as an unresolved safety issue. SBO was shown to be an important contributor to the total risk from nuclear power plant accidents. A task action plan A-44 was issued in July 1980 to address this issue and the results were published in a final report issued in June 1988 as NUREG-1032, *Evaluation Station Blackout Accidents at Nuclear Power Plants*. In essence, the findings were that the grid was assumed to be stable and reliable.

At this time, the electric power industry in the United States is dominated by vertically integrated utilities. These were interconnected initially to primarily increase reliability, but now utilities use the interconnections for commercial transactions as well. Each utility or a small group of utilities form a control area containing customers for which they are jurisdictionally responsible. The control areas are divided into reliability councils. In addition, there are power pools which are associations of utilities that have joined for the purpose of reducing the cost of producing and delivering power through coordinated operation. However, there are reliability constraints on the individual systems as indicated in North American Electric Reliability Council (NERC) reports submitted to the U.S. Department of Energy (DOE). These constraints include, but are not limited to, low reserve margins, a shortage of transmission facilities, and technical problems in transmitting power over long-distance lines.

Two relatively new factors are emerging: nonutility generation and industry restructuring. It is anticipated that, in the not too distant future, power suppliers, whether utilities, independent power producers (IPPs), or power marketers will actively compete for sales to customers who may be located anywhere on the power grid. Regional grid control will be the responsibility of centralized Independent System Operators (ISOs) in many regions. The locations, membership, responsibilities, and authority of all ISOs have yet to be defined. It is expected that these ISOs will be charged with maintaining grid reliability to facilitate the marketing of power. It is also uncertain how the current method of reliability standard maintenance through voluntary compliance with guidelines established by consensus associations will transition to the new utility structure. These uncertainties raise questions with respect to the continued supply of reliable offsite power to nuclear power plants.

Any reliability study of offsite power sources needs to consider both the quality of the voltage and frequency as needed by the nuclear generating station, the probability of the frequency and duration of a LOOP event to the subject station, and potential impacts which can occur during events (i.e., transients, low voltage, and frequency degradation). The industry structure is shifting from one with vertically integrated control by corporate entities that both own nuclear plants and have essentially autonomous authority over reliability rules and procedures. The new structure may have many commercially independent entities. There will be an as-yet undefined standards setting and enforcement process responding to commercial pressure as well as a desire to maintain reliability. These factors raise the concern, will nuclear plant offsite power requirements always be fulfilled? Also, what guarantees by the transmission provider interconnected with the nuclear plant need to be in place so that reliable power in accordance with voltage and frequency requirements can be assured for safe operation?

The answers to these and other potentially complicated questions as tasked to the NRC staff by the Commission can be provided through the performance of engineering studies, such as this by ORNL, to assess potential changes in the reliability of the grid to supply offsite power. The results of this project show that some nuclear plants are more vulnerable to grid-centered loss-of-offsite power than others. Vulnerability from the grid is discussed in detail in this report.

Acronyms

AC	Alternating Current
DOE	U.S. Department of Energy
ECAR	East Central Area Reliability Coordination Agreement
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
IPP	Independent Power Producer
ISO	Independent System Operator
LOOP	Loss-of-Offsite Power
MAAC	Mid-Atlantic Area Council
MAIN	Mid-American Interconnected Network
MAPP	Mid-Continent Area Power Pool
MVAR	Megavars (1,000,000 Vars)
MW	Megawatts (1,000,000 Watts)
NAERO	North American Electric Reliability Organization
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission
ORNL	Oak Ridge National Laboratory
PJM	Pennsylvania New Jersey Maryland Power Pool
PRA	Probabilistic Risk Assessment
SBO	Station Blackout
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
SRRO	Self Regulation Reliability Organization
VAR	Volt Amperes Reactive
WSCC	Western Systems Coordinating Council

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1 Executive Summary

The project team originally expected this reliability assessment to center around physical characteristics of the transmission system in the vicinity of each nuclear plant. Likely candidate characteristics included generating reserve margins, the quantity of off-system transactions, rates of transmission expansion relative to load growth, etc. The transient and steady state response of the transmission system were expected to be major factors as well. Modeling was expected to help identify sensitivities to factors such as contingencies, the operation of other generators, and through-flow power. Electric industry restructuring, it was thought, might impact these physical characteristics through mechanisms such as changing investment incentives and increasing off-system transactions.

Visits with a selected sample of nuclear plants, their associated system control centers, and regional councils were arranged to initiate the project. The information gathered at these visits were invaluable. This information provides a new understanding that the security and adequacy of offsite power supply to nuclear plants depends primarily upon the control area operator, the regional security coordinator, and the data, tools, rules, and training provided to ensure that the design basis requirements are met.

The project team developed a methodology to quantify the change in frequency of grid-related loss-of-offsite power (LOOP) events, and the change in time to restore power due to industry restructuring.

1.1 Overview of Findings

Findings of this report include:

- The important reliability parameters are not evident from simple performance statistics, such as generating reserve margins, number of transactions or event reports. A well-run control area and region, with satisfactory tools, procedures, training, and personnel, can provide significantly greater reliability for the offsite power supply requirements of a nuclear power plant than a control area lacking one of these attributes, even if the latter control area has superior physical resources (i.e., greater generation or transmission capabilities).

- The availability and use in the control center of real time data covering a large geographic area and advanced tools, especially on-line contingency analysis, coupled with rigorous formal operating requirements, can more than compensate for increased stress (i.e., grid congestion, supply/demand imbalance, wheeling through) on the system and can result in increased security of the offsite power supply.

- There is significant diversity among NERC regions across the country and between utilities within these regions. This diversity exists both in the rigor of the analysis to determine the design basis power requirement of the nuclear plant, and in the analysis and operation of the transmission system to ensure that the required post-contingency voltage can be maintained. There is also a significant difference among regions in the procedures for dealing with a control area or regional blackout.

1.2 Overview of Concerns

Restructuring of the electric power industry is resulting in the increasing number of financially independent entities whose operations can influence a nuclear plant's offsite power supply. Historically, the nuclear plant owner also owned and operated the transmission system, the control area, and the other generators in the immediate area and was fully responsible for the reliability of the power system. Now, each of these can be owned and operated by separate commercial entities, and there is also a NERC regional security coordinator with authority to coordinate system operator actions when reliability is threatened. This arrangement presents the following concerns:

- A key factor in providing the required offsite power quality is a determination of the offsite power design basis requirements for the nuclear plant. Some of the utilities which were visited do not appear to be addressing this important analysis in a thorough manner.

- Each entity must be aware of the nuclear plant's power requirements and must have procedures to provide that the correct action is taken under varying conditions.

- There must be contractual arrangements between these entities that assure the nuclear plant owners/operators and the NRC that required actions will be taken.

- National standards do not exist yet to guide these entities in structuring their reliability activities. Regional and local standards often lack the rigor required to function in a commercially contentious environment.

- There may be significant costs associated with both the analysis and the system operation constraints required to provide the adequacy and reliability of the offsite power supply.

- In the event of a regional or control area grid blackout, there is concern that key black start units (see Appendix D for definitions) may be under the control of a new, independent financial entity. The reliability of these units is unknown unless blackout simulation testing is also covered under contract and regularly performed.

1.3 Recommendations

Based upon the regional visits conducted and our findings as stated in the overview of concerns, the following recommendations are provided:

- NRC staff should consider the need to have nuclear power plants confirm that their offsite power basis requirements are being adequately addressed.

- The impact of restructuring across the nation in the next five years will most probably be significant; but currently, local area impacts are difficult to anticipate until ISO alignments and industry structure are fully established. NRC should be vigilant to assure that the system planning and operating rules and all proposed rule changes at the national, regional, and local levels do not significantly reduce the reliability of offsite power to nuclear power plants.

- NRC staff should reevaluate the underfrequency protection trip settings and other grid considerations in view of the concern regarding cascading trips (Section 4.2).

2 Background and Baseline Perspective

The term "National Power Grid" is used here to include the system of transmission lines, substations, relays, transformers, control-centers, etc., that deliver electricity from generating stations to factories, buildings, and homes across the United States. The basic design is built around municipalities tied together into state and regional interconnections which have grown together over the years. Many utilities, co-ops, and local rural and/or municipal systems comprise the grid. Because of this history, the grid system does not currently provide the optimized infrastructure design that would easily advance the U.S. electric utility industry along the path toward fundamental conversion from a regulated monopoly structure to a highly competitive market.

A consistently high level of transmission and distribution network reliability has been the norm in the United States for many years. This is partly due to regulatory incentives which made service reliability the primary obligation of an electric utility in exchange for monopoly access to an assured customer base. Utilities achieved reliability in interconnected system operations through construction of transmission interconnections and implementation of agreed upon guidelines promulgated by voluntary organizations such as regional councils associated with the NERC. At the operating level, cooperative arrangements provided for mutual support during emergencies, as well as for coordinated study of power system performance and the need for additional interties.

Under current NERC rules, grid control is decentralized with each utility or a small group of utilities forming a control area containing customers for which they are jurisdictionally responsible. There are 144 control areas. The control areas are divided into reliability councils composed of 1 to 33 control areas in each reliability council (e.g., the Western System Coordinating Council or WSCC). In addition, there are power pools which are associations of utilities which have joined for the purpose of reducing the cost of producing and delivering power through coordinated operation. NERC guidelines govern both scheduled and unscheduled exchanges across control area boundaries, and power pool or reliability council rules establish rights, obligations, and the manner in which emergency support is supplied.

The preferred power supply (PPS) to a nuclear generating station is the power supply from the transmission system to the plant's Class 1E distribution system. There are various designs of PPS, but they all must consist of at least two independent circuits from the transmission system to the Class 1E buses. Other sources of offsite power may also be provided such as local gas turbine generators, fossil power plants and hydro electric plants. A LOOP occurs when all sources of offsite power become unavailable to the Class 1E buses and the emergency power generators start and supply power to the buses. This report is concerned primarily with grid related LOOP events, rather than LOOP events caused by weather or plant centered incidents.

What does it mean to say that an offsite power source is unavailable? In most utility applications (non-nuclear) saying that power from the utility is unavailable means that the supply is completely removed or very seriously degraded (voltage below 70% of normal, for example). The conditions at nuclear plants, however, can be very different because of the presence of degraded voltage sensing. This level of protection was added to protect redundant safety equipment from degraded voltage conditions. Because of the added feature the offsite power supply for a nuclear plant can be "unavailable" when power system conditions are much closer to normal. An event where the switchyard voltage droops into a degraded voltage condition for a period of time long enough for the plant's degraded voltage relay to automatically transfer the Class 1E loads from the transmission system to the emergency power generators is an example of a grid related LOOP event. For the plants visited during this study, the lower limit on acceptable switchyard bus voltage ranged from 94% to 103%. The delay time on the degraded voltage relays ranged from 3 to 35 seconds.

The situation is complicated by the power system's response to contingencies. When a contingency occurs, such as the unexpected loss of a generator or transmission line, voltages and frequency are perturbed throughout the system. Various automatic and manual actions are taken to return the system to a stable, balanced condition. Some of these actions are quite fast. Generator voltage regulators can respond within a few seconds. Other actions are slower. Capacitor and inductor switching and transformer tap adjustment can take minutes. The dynamic interaction between the plant and transmission system under various possible plant and grid operating contingencies must be analyzed. Operations must be restricted such that the *post-contingency* voltage is above the acceptable switchyard voltage, considering both voltage level and time.

Taken together, this results in a significantly more stringent concept of power system availability. For example, the power system around one of the nuclear plants studied must be operated such that the voltage will not dip below 103% for more than 5 seconds as the result of any single contingency from the offsite power system. If this criteria is violated, the system risks losing the nuclear plant as the result of a single contingency. The class 1E buses will transfer to the emergency power source and this presents a risk of reactor trip. From the power system's point of view, this changes a mild problem that the power system is designed to withstand easily into a contingency with potentially serious consequences.

Avoiding a LOOP event requires several actions. The nuclear plant must perform the extensive analysis that determines the voltage requirements at the nuclear plant's switchyard bus. This analysis must be updated whenever plant conditions change; typically every few years. The power system operator must perform the analysis that determines what the nuclear plant's switchyard bus voltage will actually be under normal and contingency conditions. This analysis must be updated whenever conditions on the power system change; at least daily but typically multiple times per hour. The power system operator must also be vigilant to assure that the *pre*-contingency conditions remain within the limits determined by the *post*-contingency analysis. This is especially difficult because pre-contingency conditions that might be perfectly acceptable for all other users of the power system are often unacceptable for the nuclear plant. It is often not obvious that the conditions are unacceptable until after the contingency and the nuclear plant trip. As discussed later, adequate tools, procedures, and data for the power system operator are critical.

3 Restructuring Perspective

Restructuring of the electric utility industry is accelerating a trend of increasing stress (i.e., grid congestion, supply/demand imbalance, distant transactions and wheeling through, etc.) on the interconnected transmission system. Historically, vertically-integrated electric utilities have designed and operated integrated transmission and generation systems. The primary historical transmission function was to connect the utility's generators to the utility's customers. Utilities interconnected their transmission systems with those of other utilities to increase reliability and share reserves. Where differentials in the cost of generating electric power existed, excess capacity on the transmission system was used to move power from low-cost to high-cost locations. Because they had franchise service territories and little competition, utilities were essentially guaranteed cost recovery. Transactions designed to save money could be curtailed whenever reliability was challenged with little threat to corporate profit. Still, customers and regulators were concerned with power costs and pressured utilities to cut costs whenever possible. Consequently, bulk power transactions are steadily increasing and transmission system elements have been operated closer to their design limits for increasing amounts of time.

As the nation's power systems grew into the three large interconnected networks we have today, it became increasingly common for the actions taken by one utility to have unintended consequences for another. Loop flows, where a utility's facilities become loaded because of a transaction being carried out by two other utilities, have become increasingly problematic. This problem appears to be addressed with varying degrees of success on a case-by-case basis.

Restructuring in general, and the Federal Energy Regulatory Commission's (FERC's) 1996 landmark Order 888 in particular, promotes the unbundling of generation and transmission. Generation is becoming a competitive, commercial business, while transmission and system control are remaining regulated. This is resulting in a number of trends that are important to nuclear plant offsite power supply.

There is an increasing number of market participants that are making power transactions across the transmission system. Marketers and power brokers are interested in arranging these power transactions. Independent power producers (IPPs), merchant plants, and utility generators are all trying to sell to anyone willing to buy, not just to the native load of their host control area. This results in an increasing number of commercial transactions and an increasing amount of power being moved (wheeled) across the transmission system for commercial reasons.

3.1 Self Regulating Reliability Organization

In response to industry restructuring, NERC is also restructuring. Historically, NERC was a voluntary membership organization that recognized the primacy of each control area. NERC itself provided general guidelines concerning good utility practice. The amount of added detail provided by each regional council depended on the wishes of the membership and ranged from Mid-Atlantic Area Council (MAAC) and Pennsylvania New Jersey Maryland Power Pool (PJM) operating as a tight pool with real-time regional operations to the Southeastern Electric Reliability Council (SERC) where almost everything is left to the individual utility.

NERC is transforming itself from a voluntary to a mandatory organization with policies replacing guidelines. NERC appears to be headed in the direction of becoming a self regulation reliability organization (SRRO) recognized by FERC with the first step being a change of name to the North American Electric Reliability Organization (NAERO). Presumably the new policies will begin to become national standards, with some specificity, developed in an open forum. This is a necessary trend and probably will result in higher grid reliability. Unfortunately, it does mean that system operating rules will not be set exclusively by the owners of nuclear plants. Therefore, it is recommended that both the plant owners and NRC be vigilant to assure that system operating rules addressing the reliability and adequacy of offsite supply are maintained. This may require new actions on the part of plant operators such as executing contracts with adjacent facilities to assure performance of required functions. It will certainly require monitoring of all proposed rule changes to provide that all new contracts and modifications to current contracts are made as required.

3.2 Reliability, Adequacy and Security

Vertically integrated utilities address reliability, adequacy and security under regulatory supervision.[1] However, restructuring is increasingly splitting the way adequacy and security are addressed, with adequacy now being left to markets. The responsibility for security is changing as well, with control area operators being supplemented by regional reliability coordinators able to compel action by all parties if they perceive a threat to system security.

While the grid is increasingly stressed by commercial transactions, this does not necessarily mean that the grid itself or the supply of offsite power to nuclear plants will become less reliable. As long as the generation/load balance is preserved, without exceeding transmission limits, grid reliability can be maintained. Vigilant monitoring of system conditions and commercial action, and aggressive control when required, can facilitate operations much closer to the equipment's physical limits. The electric utility industry is used to addressing this from the supply side, increasing the amount of generation and/or transmission. However, there has always been a demand side option exercised as a last resort; load can be shed to offset a generation shortfall. Making increased use of this option requires both institutional and technical changes. Because remote conditions can have widespread impacts (see Sect. 4.1 and Appendix B), it is necessary for the System Controller (i.e., control area, Independent System Operators [ISOs], etc.) to monitor a large portion of the transmission system in real-time. Institutionally this requires an organization that spans much more than the local control area. The establishment of 23 regional reliability coordinators has helped fill this need. The emergence of regional ISOs will further help. The ISOs provide reliability coordination over a large geographic region, and also provide an extensive exchange system for the free market sale and purchase of power over the region controlled by the ISO.

3.3 Reliability Consequences

As one would expect, not all control centers have the same tools, procedures, contractual arrangements, or operating philosophies. There appears to be a fortunate correlation between the amount of stress the transmission system is under (for physical or commercial reasons) and the tools being provided to most of the major system operators and the formality of the operating procedures being used. This is not surprising since stressed systems would be the first expected to recognize the need for additional operator tools. What may be surprising is that the existence of advanced tools, especially on-line contingency analysis analyzing a large geographic area, coupled with rigorous formal operating requirements, in the cases observed, seem to more than compensate for the increased stress on the system, often resulting in increased reliability for nuclear plant offsite power supply. However, there are large sections of the country where stress is just beginning to be seen. In these areas, the needed advanced tools like on-line contingency analysis are not currently being used to the full extent that may be required in the next five years.

Existing "standards" for both reliability and system restoration lack specificity and compulsion. NERC standards are derived from the older guidelines, which could be viewed as suggestions for good utility practice. This is not surprising as NERC was formed as a voluntary organization.

[1] Reliability refers to all actions taken to assure that the system remains intact and continues to operate within acceptable standards. NERC views reliability as composed of adequacy and security. Adequacy addresses the requirement to have enough generation supply to meet load demands. Security refers to the ability of the system to withstand sudden disturbances or unexpected loss of system components.

4 Lessons Learned

The ORNL/NRC team has visited several nuclear plant local control areas located in ten of the NERC regions across the United States. Using the protocol (See Appendix C) developed for this task, numerous questions have been asked and significant amounts of data compiled. It is from these visits that the following information has been gathered. Without exception, all of the plant, utility, and reliability council personnel were open and forthright. They provided all information requested and did not hesitate to state when information was unavailable or they were uncertain. As a group, power system operators care deeply about reliability and are willing to express strongly held beliefs. The team is reasonably confident that all participants tried to provide as accurate a description as possible of their operations. The interview process proved to be an effective way of evaluating the interaction and level of formality between the plant and transmission system.

There is significant diversity between regions and between utilities within each region. This diversity exists in the rigor of the analysis to determine the design basis power requirement of the nuclear plant. Some plants have not performed dynamic motor starting studies to be used in the analysis and operation of the transmission system to ensure that the required post-contingency voltage can be maintained. This diversity also exists in the way the power system itself is planned and operated. Some control areas have no restrictions on system operation related to post contingency voltage at the nuclear plant. There is also a significant difference in the system restoration procedures needed to deal with offsite power restoration after a control area or regional blackout.

4.1 Protocol between Plant and System Operator

Some plants have very well defined and proceduralized protocols between the plant and the system control center. Others rely on verbal, informal communication between the transmission and plant operators to sort things out during a grid event. Typically, plants with thorough procedures are the plants in areas with a high density of generation and transmission, and where the control area operator is already functioning as an ISO. An example of this is ISO New England and a plant in New England, where there is a detailed control algorithm based on the power flow throughout the interconnection. When the power flow reaches a certain level established by procedure, the plant in New England is required by the ISO to reduce power to ensure that voltage and stability can be maintained in the event of a contingency. In addition, there are well defined voltage limits in the plant's switchyard, and action statements for circumstances where the voltage limits cannot be met, all clearly defined by procedures at the plant and at the control center. The system operator utilizes state estimation and on-line contingency analysis to assure that the postcontingency voltage will remain acceptable.

At a plant in the Midwest, on the other hand, we were told that the feed to the emergency station service transformer is contractually guaranteed to be above 62.0 kV (0.90 pu) by the power supplier for this bus, a separate financial entity. However, a review of a plant document "Student Test Lesson on AC Electrical Distribution," states that the voltage is maintained within 70.3 to 73.0 kV (1.02 to 1.06 pu). The operators we spoke to indicated that they thought the minimum acceptable voltage was 65.5 kV (0.95 pu). The ORNL review team was unable to determine the actual plant requirements.

During a Midwest visit, the team learned about a grid condition that occurred in June of 1997 that caused overload alarms at a Nebraska nuclear plant's substation, low voltage condition at an Illinois nuclear plant substation and low voltage areas across Eastern Iowa, Southwestern Wisconsin, and Western Illinois areas. This case has been identified as NERC Disturbance No. 10 in 1997 and may be found on the internet at http://www.nerc.com/dawg/database.html/. Appendix B to this report discusses a case study of this disturbance. A major contributor to the seriousness of this incident was the lack of a system operator with sufficient real-time data, analysis tools, and authority to identify the problem and take prompt remedial action. This case study shows the potential impact open access and increased demand can have on the offsite power at several nuclear power plants. Some nuclear power plants appear to be more vulnerable to grid disturbances than others because of their geographic location in the grid system, the operating structure for the control area and region, and the potential for major local power transfers in their area.

4.2 Cascading Trips Due to Underfrequency Protection

Pressurized water reactors typically have an underfrequency trip at 57 or 58 Hz. There is a concern that if there is a severe grid disturbance, the underfrequency tripping of the plant could cause cascading loss of generation if the transmission control system does not respond to shed load and island quickly enough to maintain frequency above these levels. When the grid is separated into islands, frequency control and security are precarious. Some utilities (such as those in Florida) have specific plans to use islanding. Many utilities plan simply to respond to contingencies as they occur, and this would allow many islanding scenarios to be within the realm of possibility. Underfrequency tripping could also occur during the islanding process causing cascading trips within the islands. Personnel at a utility in New England told us that the ISO protocol should require rigorous analysis for this scenario.

4.3 Black Start Testing

Emergency grid restoration and black start standards vary dramatically from utility to utility. While there has been universal acknowledgment that restoring offsite power to nuclear plants is the utility's highest priority, this translates into very different performance expectations at the various areas visited. In some cases there are black start capable units adjacent to the nuclear plant. In other cases the black start units are a significant distance away and must re-start other thermal units before offsite power can be restored to the nuclear plant. Some control areas regularly test both the black start units themselves and the system restoration plan (through simulation or exercises). A utility in SERC has capability to automatically isolate their transmission system backbone and begin system restoration. In the other extreme, some control areas simply plan to use the best efforts of experienced operators to determine the most effective way to restore the system based upon actual conditions at the time. We frequently heard system operators from neighboring systems to the plant indicate their intention to also utilize their best efforts to help restore offsite power to the nuclear plant. In no case did we find contractual arrangements that required this response. Credible estimates of restoration times range from 10 minutes to over 5 hours.

4.4 Analysis and Operational Tools

At most nuclear plants, when a reactor and generator trip occur, safety-related loads are started in load blocks from the offsite power source using a load sequencer. After each load block is accelerated in a few seconds, the next load block is started. There are a number of parameters that must be determined to ensure that the load blocks are started successfully; the analysis must determine the required MWs and MVARs, as well as the minimum voltage, and the minimum time required for voltage restoration. In addition, the analysis must consider the effect of tripping the plant's generator, and whether the offsite power supply is capable of maintaining adequate voltage under worst case transmission system configuration and load flow conditions. This is an extensive amount of analysis, but if it is not performed the system operator cannot know what voltage must be maintained. There may be normal grid operating conditions which result in significant safety system inoperability in the event of an accident.

Planning cases, real-time data, on-line state estimation, and automatic contingency analysis can identify problems, find remedial actions, and help the system operator and regional security coordinator ensure that the postcontingency voltage at the nuclear plant will be adequate. For example, at a plant in the Southeast, generator real power output is restricted to prevent potential instability problems under specific transmission line outage conditions. At another plant in the same region, the unit's precontingency VAR output is limited to mitigate problems under certain transmission system conditions. In both cases, the transmission system operator monitors the interconnection and notifies the plant operator when action must be taken. These potential problems would not have been detected unless planning cases were developed covering expected system base and contingency conditions. Planning cases cannot cover every possible transmission, generation, and loading configuration; the use of state estimators and on-line contingency analysis to test current system conditions is needed to assure that the system will perform adequately if a contingency occurs. Ten of the seventeen control centers visited had real-time tools available for the system operators to use. The best also had procedures in place requiring that the power system never be operated in a condition where it was not known that the consequences of next contingency were acceptable.

The interconnected power system can be critically stressed by disturbance at remote locations as shown by the widespread western blackouts in the July and August of 1996 and the example of a near miss in the Midwest in June of 1997 (Appendix B). The control area operator and/or the regional security coordinator must have real-time data from a large enough geographic area to be able to recognize potential threats. Coordinated control is required in the Northeast over an area ranging from Pennsylvania to north of the Canadian border. Seven of the seventeen visited control centers had real-time data from a broad geographic area available to the control area operator, the regional security coordinator, or both.

The availability of real-time data and analysis tools is especially important when the system is stressed and conditions can change rapidly. Based upon our visits it appears that some utilities, at least on occasion, may operate the system without knowledge of how the next contingency might impact the grid.

5 Development of Incremental Changes for Loss-of-Offsite Power (LOOP) Frequency and Duration

A methodology has been developed to quantify the change in frequency of grid-related LOOP events, and the change in time to restore power after a regional grid blackout as a result of restructuring. This methodology has been applied to all the plants visited and the results have been provided in Appendix A. The methodology is based on subjective criteria which quantify the potential impact of restructuring on individual nuclear plants. However, it should be noted that in some regions of the country restructuring has not yet taken place. Plants that appear to have potential weaknesses associated with restructuring are assigned multipliers which increase their LOOP frequency or increase their regional grid blackout recovery time. Conversely, plants that have had or that are preparing to have a rigorous analysis of their system and control of the transmission system to ensure adequate post-contingency nuclear plant voltage are assigned multipliers which decrease their loss of offsite power frequency. Plants that have well defined and contracted grid blackout procedures are assigned multipliers which decrease their regional blackout recovery time.

To estimate the change in the frequency of grid-related LOOP events at each nuclear plant, the multiplying factors are used with the average national LOOP frequency to modify the national average number based on the particulars of the individual plant. While significant differences were found between nuclear plants, between utilities, and between regions, no evidence from this sample of 17 plants would support changing the national average LOOP frequency. The ORNL team has developed six LOOP frequency multiplying factors. The individual LOOP factors are multiplied together to find an overall multiplying factor. The overall factor is multiplied times the average national LOOP frequency to estimate the plant-specific grid-related LOOP frequency.

Similarly, estimates of the time required to restore offsite power to each of the visited nuclear plants following an area or regional grid blackout have been developed and are also discussed in Appendix A. This required development of five subjective recovery time factors. Unlike the LOOP method, these recovery time multipliers are multiplied together to find the estimated plant specific recovery time directly. There is no need to use an average national recovery time. These factors are based on considerations of the individual plant's interface with the control area, the control area's interface with the region, and the operation of the region, all in light of the changes due to restructuring.

In general, if the plant, control area and regional operating procedures have been carefully developed based on thorough analysis and understanding of transmission system operation and the nuclear plant's requirements, then the frequency of grid-initiated LOOP is considered to be reduced. In this case, the multiplying factor is less than one. On the other hand, if there are uncertainties in the nuclear plant requirements or in transmission system operation or response, or the response of adjacent power plants, or the procedural or contractual commitments of any of these entities, then the frequency increases, and the multiplying factor is greater than one.

If the national average frequency of grid-related initiating events is considered to be 0.004[2] per site calendar year, then the variability as determined in Appendix A would range from 0.0136 to 0.002 per site calendar-year, for the regions studied. The multiplier for the grid-related LOOP average national frequency ranges from 0.5 to 3.4.

After visits to load-dispatch centers responsible for 17 plants, our assessment of the time to recover from an area or regional grid blackout ranges from 0.2 to 5.1 hours, and averages 2.0 hours. The variability is discussed in Appendix A.

The primary finding of this study is that restructuring will impact LOOP frequency and blackout recovery time through power system operator capability. Areas of significant variability between load-dispatch centers are operator capability and having the real-time data and analysis tools available to the operator as well as having in place the rules, operating procedures, and

[2] NUREG-1032 had 12 grid-related site initiating events in 664 site calendar years giving them a frequency of 0.018 per site calendar year. The recent study presented in INEEL/EXT-97-00887 provided two grid-related site initiating events over 1065 site calendar years which provides a frequency of 0.0019 per site calendar year. Eight of the Florida events from NUREG-1032 were dropped because they are not representative of current operating practice. For the purposes of this report, the National Average Frequency of 0.004 per site calendar year is used for illustration purposes. This number is what was used to establish the range for the regions studied.

contracts that are needed. Evaluation methods for these capabilities are not as advanced for power systems operations as they are for nuclear plant operations. Consequently, the evaluation presented in this report is subjective.

The subjectivity appears in three categories. First, the LOOP frequency assessment is a multiplier applied to the national average. Adjusting the national average LOOP frequency to more accurately reflect current operations is an appropriate area for engineering judgement. Second, the relative weighting applied to each of the multipliers (for both LOOP frequency and blackout restoration time) is based upon engineering judgement as explained in Appendix A. Third, the score given to each nuclear plant for each criteria is based upon an assessment of information provided during system control center visits. Use of a single assessment team and consistent protocol for each control center visit improves consistency in the evaluations.

The ORNL team has reviewed NERC records (on the internet at http://www.nerc.com/dawg/database.html/) for all the major national power outages in the years 1994 through 1997 inclusive. This review was done to determine general reasons for recent large grid-related outages and to provide a basis for the criteria and multiplying factors discussed in Appendix A. Most of these outages did not impact nuclear power plants offsite power, but all of the outages were major and grid-centered. The average time to restore power on the grid was approximately 3 hours. The number of major outages each year ranged from 21 to 29 with an average of 27. A detailed review of these 106 outages has confirmed the Appendix A criteria for evaluations. The following general statistics of the outages are shown in Table 5.0.

Table 5.0 Statistics for major outages in 1994–1997

Regional Location
West - 38%
Northeast - 30%
Midwest - 26%
Southeast - 6%

Cause of Outage	W	NE	MW	SE	Total
Due to weather - 25%	6	3	13	4	26
Due to equipment failure - 47%	26	15	6	3	50
Due to human error - 12%	4	5	4	-	13
Due to vandalism - 9%	4	4	3	-	11
Due to low reserves - 7%	-	5	1	-	6

6 Summary and Recommendations

Some nuclear plants are more vulnerable to grid-centered loss-of-offsite power events than others. Vulnerability from the grid is influenced by the following factors:

1. Transmission system or operator capabilities
   a. Real-time tools
   b. Geographic scope
   c. Training

2. Industry structure, contracts and procedures
   a. Formal procedures that clearly define responsibilities
   b. Contracts to compel performance from all market participants

3. Transmission system physical vulnerabilities
   a. Sensitivity to throughflow power
   b. Voltage response under contingency
   c. Other required generating facilities
   d. Relay misoperation

Increased commercial activity and increased emphasis on profits increases the stress on the transmission system. Also, the transmission system operators' skills are being increasingly challenged. This would lead to an expectation that nuclear plant offsite power supply reliability will be reduced as a result of restructuring, but this is not necessarily the case. Operators at some utilities are receiving better training and greatly improved tools. In some areas, real time contingency analysis is being performed to analyze the present capability of the transmission system to supply the nuclear plant voltage requirements after the occurrence of any credible contingency.

Contractual arrangements and operating procedures are also becoming more specific. At one plant in the WSCC, detailed plant voltage requirements have been translated into transmission system nomograms and incorporated into contracts, resulting in clearer responsibilities, identification and correction of inadequacies, and more formal operations. Assessment of the vulnerability posed by restructuring involves more than an examination of reserve margins and system stability studies. In areas without real-time tools and data covering a broad geographic area, it is the capabilities of the transmission operators that is the dominate concern.

While the future is far from certain, restructuring will likely progress significantly over the next five years, at least in the bulk power markets. Commercial pressure will increasingly stress the power system. Fortunately, the industry has the potential to adjust to meet this challenge. Congress will either grant FERC new authority or FERC will discover that it already has sufficient authority to oversee an industry reliability organization with mandatory rules. NERC's transformation to NAERO should be completed. While it is likely that true national standards for all activities that impact reliability will not be in place, this process will be well underway. Regional security coordinators will be fully in place in all regions. Real-time data covering large geographic areas will be available to operators. Real-time analysis tools will be utilized in most, if not all, control centers. Effective, operating procedures, contracts, and standards can significantly increase the security of offsite power supply to nuclear plants. However, there is a real danger that the stress added by increased commercial activity will exceed some regions ability to change and cope. In these situations, the risk of system failure, including the risk of inadequate supply of offsite power to nuclear plants, will increase. Nuclear plant owners will have to actively participate in industry restructuring at the local, regional, and national levels to assure that nuclear plant requirements are met.

Information in this report is generally limited to the 48 contiguous states of the United States. Table 6.0 names the member councils and gives the abbreviation by which each is usually called. Figure 6.0 shows the geographic location of the member councils throughout the United States.

Table 6.0 Member Councils of the North American Electric Reliability Council

ECAR - East Central Area Reliability Coordination Agreement
ERCOT - Electric Reliability Council of Texas
FRCC - Florida Reliability Coordinating Council
MAIN - Mid-American Interconnected Network
MAAC - Mid-Atlantic Area Council
MAPP - Mid-Continent Area Power Pool
NPCC - Northeast Power Coordinating Council
SERC - Southeastern Electric Reliability Council
SPP - Southwest Power Pool
WSCC - Western Systems Coordinating Council

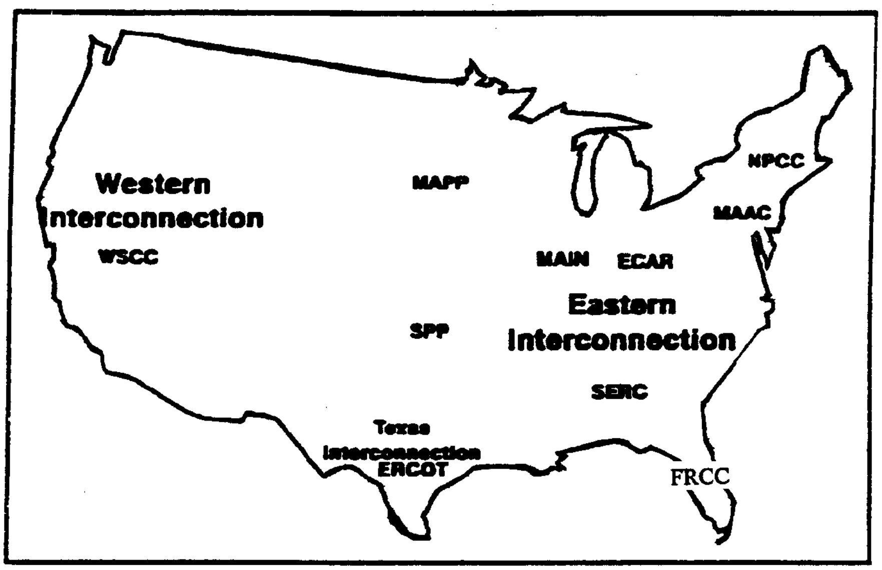

Figure 6.0 North American Electric Reliability Councils

Restructuring's impact on each of the reliability councils varies significantly:

ECAR - ECAR does not, itself, have any real-time operations. Only one of the 16 control areas, and one of the three regional security coordinators, was visited for this report. ECAR does produce guidelines and standards for planning and operations but restructuring has not yet had a major impact on ECAR.

ERCOT - There are ten control areas in ERCOT but only one ISO and one regional security coordinator. The regional reliability coordinator receives some data in real-time and is scheduled to receive all real-time data by years end. The organizational structures are in place to allow ERCOT reliability to improve under restructuring. ERCOT is an independent interconnection with no synchronous ties.

FRCC - The physical vulnerability of operating on a peninsula rather than increased commercial pressure has led the Florida utilities to coordinate operations and rely on a strong regional security coordinator, real-time data from the entire region, and more formal operations. Restructuring will likely force changes in the administrative structure (independence for the regional security coordinator, for example) but the technical tools are already largely in place.

MAAC - PJM/MAAC continues to operate as a tight power pool with rigorous formal operating procedures. Operations are coordinated with neighboring regions to cover a broad geographic area.

MAIN - MAIN recently started actively operating as the regional security coordinator. Real-time data and analysis tools are being implemented. Each control area still has significant autonomy and there are large differences between control areas in terms of capabilities and formality of operations. If MAIN becomes an ISO, as some in MAIN are actively pursuing, nuclear plant offsite power supply reliability should be enhanced.

MAPP - MAPP has a single regional security coordinator but it is not operating with real-time data or analysis tools. Though there have been large transactions moving over great distances for quite some time utilities visited for this study have been slow to recognize the need for advanced tools or formal procedures.

NPCC - NPCC has no real-time operation and allows the five control areas to each operate as regional security coordinators. The control center visited as part of this report, however, is an ISO, utilizes on-line contingency analysis, and has rigorous formal operating procedures. Real-time-data is shared and operations are coordinated with adjacent regions. From the perspective of nuclear plant offsite power reliability this region is well on its way through restructuring.

SERC - There is little enthusiasm for restructuring in the SERC region and the regional reliability council is not a strong independent voice. However, the three utilities visited for this report all have excellent evaluations. The control areas have formal procedures, real-time tools, and real-time data from a large geographic area. So far there has not been much independent commercial activity

SPP - SPP recently initiated operation of a security coordinator. Real-time data and on-line contingency analysis capabilities are being implemented. If these developments can be extended to include rigorous formal region wide operating requirements, nuclear plant offsite power reliability will be enhanced by restructuring.

WSCC - WSCC is a large region with diverse progress towards restructuring. WSCC is an independent interconnection with no synchronous ties. The council members have a long history of working together on technical and reliability issues. While there are three regional security coordinators, they are employees of the council rather than being utilities assuming the role for their neighbors. WSCC has the benefit of being able to study the California experience at close hand.

Table 6.1 provides a regional summary of the findings of this study. The results are not exhaustive because of the limited number of system control centers visited, as shown in the first two lines of the table. There is wider use of advanced system operator tools (such as state estimation and on-line contingency analysis) than there is movement towards full industry restructuring, as shown by the third and fourth lines on the table. Four regions employ widespread use of advanced tools (ERCOT, FRCC, MAAC, WSCC) while three (ECAR, MAPP, SPP) show a serious lack in this area. In one region (MAIN) the use of advanced tools varies from control area to control area. In two other regions (NPCC and SERC) the control centers visited were using advanced tools but there is no established standard for the region so a full determination could not be made.

Implementation of standards, procedures, and contracts to facilitate operations in a restructured industry are not as well advanced. Four regions were identified where concerns already exist (ECAR, MAIN, MAPP, and SPP) and one where the process is in too early a stage to evaluate (SERC). In two regions (NPCC, WSCC) restructuring is well underway at the control centers visited. Progress at other control centers within the regions was not evaluated. A uniform approach to restructuring is being implemented in one region. Finally, two regions have a good start on rules and procedures but much remains to be done, these are indicated with a blank entry (ERCOT, FRCC).

There is only one region, MAAC (PJM), where concerns over the response to restructuring and nuclear plant offsite power supply might be relaxed. In all other regions restructuring poses both a promise and a concern.

Table 6.1 Advances in real-time tools, data, and industry structure by NERC region

	ECAR	ERCOT	FRCC	MAAC	MAIN	MAPP	NPCC	SERC	SPP	WSCC
Nuclear plant sites[3] in region	7	2	3	8	10	5	13	15	6	4
Nuclear plant sites / Control center interviews	1	2	1	2	3	1	1	3	1	2
Real-time tools & data geographic scope	✗	✓	✓	✓	S	✗	S	S	✗	✓
Commercial restructuring	✗			✓	✗	✗	S	✗	✗	S

✓ Advances implemented and consistent throughout the region
S Advances implemented at the control centers visited but may not be throughout the region
✗ Concerns identified in some control centers during visits

The impact of restructuring across the nation in the next five years will most probably be significant, but currently, local area impacts are difficult to anticipate until ISO alignments are fully established. Changes in the alignments and restructuring need to be closely followed. Nuclear plant related reliability is expected to decline most dramatically in ECAR, MAPP, and SPP over the next one to three years. In the longer run, commercial pressures should force structural changes that would be assumed to increase reliability.

Based upon these evaluations and previous discussions, the following recommendations are provided:

- NRC staff should consider the need to have nuclear power plants confirm that their offsite power basis requirements are being adequately addressed.

- The impact of restructuring across the nation in the next five years will most probably be significant; but currently, local area impacts are difficult to anticipate until ISO alignments and industry structure are fully established. NRC should be vigilant to assure that the system planning and operating rules and all proposed rule changes at the national, regional, and local levels, do not significantly reduce the reliability of offsite power to nuclear power plants.

- NRC staff should reevaluate the underfrequency protection trip settings and other grid considerations in view of the concern regarding cascading trips (Section 4.2).

[3] Multiple nuclear units at the same location are counted as 1 site.

Appendix A

Multiplying Factors for Grid-Related LOOP Frequency and Duration

Multiplying Factors for Grid-Related LOOP Frequency and Duration

A set of criteria have been developed to provide a tool for assessing the impact of electric industry restructuring on individual nuclear plants. The first group of criteria are multipliers for the frequency of Loss of Offsite Power (LOOP), and the second group are the multipliers for the number of hours to restore power after an area blackout. To estimate the frequency of Loss of Offsite Power and the duration of Area Blackout recovery time at each nuclear plant, individual criteria scores in each group are multiplied together. The individual criteria scores are subjectively determined for each plant. (For this analysis the scores were based upon information obtained during visits to the plants control area operations center.) The LOOP multiplier and Area Blackout recovery time estimate is then determined from the criteria scores.[4]

The LOOP multiplier is to be multiplied times the National Average Loss of Offsite Power Frequency described in Section 1.3 to find the plant specific frequency. Some of the LOOP multipliers have values of less than one because the criteria reduces the risk of LOOP evaluation if the plant scores well. Likewise, some of the LOOP multipliers have values greater than one because the criteria increases the risk of LOOP evaluation if the plant scores badly.

Similarly, the Area Black Out recovery time in hours is found by multiplying the individual criteria together. The last multiplier, described under Item e. below, is actually the estimated recovery time in hours, thus a national average number does not have to be used as is the case with the LOOP multipliers described above. As with the LOOP multipliers above, some of the recovery time multipliers have values of less than one because the criteria reduces the estimated recovery time if the plant scores well. Likewise, some of the recovery multipliers have values greater than one because the criteria increases the recovery time evaluation if the plant scores badly.

The multipliers are subjective, but they are based on the findings of the interviews and the limited historical evidence of LOOP event. The original LOOP frequency studies, NUREG 1032, "Evaluation of Station Blackout Accidents at Nuclear Plants" and INEEL/EXT-97-00887, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants", were performed during a pre-restructuring environment. They were to establish LOOP frequencies based on historical data. NUREG 1032, page A-8, states that "The historical data shows that losses of offsite power as a result of grid - related problems account for no more than 19% of all losses of offsite power. Attempts to find characteristics to classify site, design and location features that affect the expected frequency of grid loss have not been successful. An investigation into the various utility transmission and distribution system reliability characteristics was beyond the scope of this study"

INEEL/EXT-97-00887 found only 6 grid related LOOP events out of a total of 151 LOOP events from 1981 to 1996. The most recent grid related event was the Summer plant event of 1989. This group of 6 is not an adequate population to quantitatively classify grid configuration and management features that contribute to LOOP events, especially in light of deregulation. Data for an analysis of recovery times presents the same dilemma.

INEEL/EXT-97-00887 states that "... it may be inferred from a comparison of the frequency between the present study and NUREG 1032 results that grid failure is less likely to occur now than it was prior to 1985." (P. 9) The ORNL team does not necessarily agree with this conclusion. There were two regional black out events in the WSCC on July 2, 1996 and August 10, 1996. The August 10th event resulted in a partial LOOP of Diablo Canyon. There was a "near miss" regional event in MAPP on June 10, 1997 which is described in Appendix B; this event could have impacted potentially some 12 nuclear plants. Finally, there was a loss of 3 of 4 offsite sources at the Clinton plant on 6/29/98; this event was due to severe weather, not grid conditions. We have reviewed the grid related LOOP events, the 2 WSCC events and the MAPP event and provide synopses as follows:

LER 395-89-012 Summer Nuclear Station. A Turbine Trip/Reactor trip occurred due to a technician error. Three other generating stations tripped while attempting to compensate for the VARs lost on grid after the turbine trip. As a result of the loss of the four generating stations, the offsite voltage to the Engineered Safety Feature busses decreased below the setpoint of the undervoltage relay and power was transferred to the emergency diesel generators.

LER 331-84-028 Duane Arnold. This LER discusses a degraded voltage condition and the automatic transfer to on site power,

[4] The scores give credit for modifications that the control areas are presently implementing but may not presently be in service.

but provides no detail as to the cause of degraded voltage condition other than to say that the offsite power was less than 92.3% for a period of eight seconds, which was the criteria for tripping the essential bus breakers.

LER 312-81-034 Rancho Seco. This LER states that the voltage in the switchyard decreased to 207 kV due to the high demand for electricity in the area. The SMUD analysis assumes that a minimum voltage of 214 kV is available to the NSS buses, so the diesel generators were started.

LER 312-81-039 Rancho Seco. This LER again states that the voltage in the switchyard decreased to 206 kV due to high demand for electricity in the area. The SMUD safety analysis assumes a minimum voltage of 214 kV is available to the NSS buses, so the diesel generators were started.

LER 251-85-011 Turkey Point. Brush fires in Southern Florida shorted out three 500 kV transmission lines simultaneously. Southeast Florida islanded from the grid. The overloaded island system voltage collapsed and caused the loss of offsite power.

The WSCC event of 7/2/96 involved a short circuit on an 345 kV line in Wyoming and another in Idaho, then cascading generation and line trips in Oregon and California due to a widespread system stress condition. The event resulted in outages in Idaho, Utah and Colorado. Five islands were created.

The WSCC event of 7/3/96 began the same way with nearly simultaneous independent line trips, but system operators in Idaho manually shed 1,200 MW of load to prevent a repeat of the 7/2 event.

The WSCC event of 8/10/96 began with random multiple transmission line outages in Washington and Oregon which resulted in cascading generation and line trips in Oregon and California. Service to about 7.5 million customers was interrupted.

The MAPP and MAIN near miss of June 10, 1997 is discussed in Appendix B, but, again, there was regional system stress, tripping of individual lines, and cascading tripping of lines and generation over a widespread area was narrowly averted.

With the exception of the brush fire, (LER 251-85-011), all of the above events could have been mitigated by appropriate system operator action. Dynamic analysis of the nuclear plant's voltage and time requirement, analysis of the plant's dynamic impact on the system, real time system contingency analysis, and data acquisition over a widespread geographic area can significantly contribute to reducing LOOP frequency.

The following five LERs were reports of analyses which determined that offsite power sources could be jeopardized under certain grid conditions:

LER 313-91-010 Arkansas Nuclear One, Unit One. An engineering evaluation determined that during certain operating conditions, the 161 kV offsite power source may not be able to maintain adequate voltage when the 500 kV autotransformer was unavailable.

LER 245-92-020 Millstone Unit 1. An engineering analysis determined that disturbances in the regional electrical transmission grid occurring in combination with certain operating conditions could result in postulated instability of the Bulk Power system, resulting in a Loss of Offsite Power to Millstone.

LER 305-93-010 Kewaunee. A study identified the potential for certain transmission line contingencies to cause the KNPP generator to go unstable, and, as a result, to cause all transmission sources into the plant's transmission system to trip.

LER 245-94-001 Millstone Unit 1. A study determined that for a postulated LOCA under certain system conditions, inadequate voltage would be available at the 4160 Volt emergency buses, and the degraded voltage relays would separate the buses from the offsite source.

LER 323-95-007 Diablo Canyon. A study determined that during certain peak system loading conditions, local fossil fuel plants had to be in service in order to meet DCPP voltage requirements. A review of the offsite power supplies has identified that the DCPP 230 kV voltage requirements may have been degraded 47 times since 1990.

The issues discussed in the above reports have been summarized in a set of criteria. There are six criteria for LOOP frequency, and five criteria for area blackout recovery time. These criteria are presented below. NUREG 1032 and INEEL/EXT-97-00887 did not address industry restructuring and the approach each control area is taking to address restructuring. The site specific design and location features concerning grid centered LOOP frequency are now being addressed by the set of criteria. The criteria provide a means to quantify these differentiating features. Consistency of the multipliers was verified using the Analytical Hierarchy Process. Table A.1 shows the scores, the associated criteria multipliers, and the projected change in Loss of Offsite Power frequency and the Area Blackout Recovery time.

1. LOOP Frequency (Average Events/Year) Criteria and Multipliers

   LOOP Multipliers: For each of the following criteria, the plant is subjectively scored on a scale of 0 to 100%. A perfect score is 100%, and a complete deficiency is 0%. The multiplier is then scaled from this score using the values given in each criteria. A multiplier greater than one indicates an increase in LOOP frequency, a multiplier less than one indicates a decrease. The multipliers were subjectively determined based upon the engineering judgement of the authors as to the relative importance of each criteria. The overall multiplier for the plant is found by multiplying the individual multipliers together.

   a. Has the nuclear plant voltage requirement been determined through rigorous evaluation of all relevant conditions including evaluating the effect of a generator trip? In the event of an accident, safety related loads are typically sequenced on in blocks. The minimum acceptable switchyard voltage for these blocks is determined by a detailed analysis of the plant's electrical distribution system to find the voltage drop from the terminals of the reserve auxiliary transformer to the terminals of the safety related motors as they are sequenced on. Seemingly small considerations, such as the resistance of an overload heater, can have a major impact on the outcome of this calculation. Starting these blocks of motors from the immediately available offsite supply is an event of high stress to the plant's distribution system. Often, the minimum voltage requirement at a particular motor, such as a valve actuator motor required to start at full locked rotor torque, may be the driver for the minimum voltage which is allowable at the reserve auxiliary transformer terminals. Has this voltage requirement been provided to the system operator, the regional security coordinator and other control area operators responsible for maintaining voltage? This is a highly weighted criteria because the establishment of a detailed voltage requirement may indicate that plant and transmission engineering staff have understood the problem of post generator trip voltage and performed the extensive analysis needed to determine the minimum voltage requirement.

      To find the multiplier, a score of 0% corresponds to a multiplier of 1.4, and a score of 100% corresponds to a multiplier of 1.0. The multiplier here is the maximum because this criteria is central to understanding and addressing the voltage requirement of the plant. This criteria is common to each of the above LERs.

   b. Does the nuclear plant voltage remain constant or rise when the nuclear plant trips under all allowed operating and credible contingency conditions? Generator trip is an expected result from most accident conditions. The generator typically provides VAR support to the grid to support voltage. When the generator trips during grid conditions such as high system stress, high load levels, high levels of power being exchanged across the control area, or when local generation support is out of service, this may result in a voltage droop at the switchyard. This droop occurs at the worst time - starting of the accident loads. Analyzing the grid and grid operation to determine the post generator trip voltage for various system conditions is a non-trivial exercise. All potential conditions of load flow, local generation on or off, system load, etc. should be considered. For control areas, regional security coordinators, or ISO's that have real time state estimators, this may not be a significant problem, for others, the scope of calculation may simply be above their capability. Some control areas have developed a detailed set of charts or a nomogram to determine whether nuclear plant offsite power is operable under limiting grid conditions. When the plant is approaching a condition where offsite power would be declared inoperable, other local generation may be required to be brought on to ensure post contingency voltage adequacy. (The plant receives a score of 100% only if the voltage either cannot drop under any conditions or there are sufficient procedures in place to assure adequate analysis of operational requirements and compelled operation of other required facilities - Crystal River 3, for example.) This criteria assures that the required post trip voltage will be available, either due to procedural controls or due to features of the grid configuration.

Table A.1 Multiplying Factors

Utility		LOOP a Analyzed & Passed	b V up or Procedure	c Timing	d Geographic Scope	e Real-time Tools	f Training	Multiplier	Blackout Time a Formal Procedure	b Automatic	c Drills?	d All utility Generators	e Direct to Nuc?	Hours
	Bad	1.40	1.30	1.30	1.10	1.20	1.10	**3.4**	2.00	1.00	2.00	2.00	4.00	**32.0**
	Good	1.00	1.00	1.00	0.80	0.80	0.80	**0.5**	1.00	0.70	1.00	1.00	0.20	**0.1**
A	*Score*	100%	100%	100%	100%	100%	100%		30%	0%	30%	100%	95%	
	Mult	1.00	1.00	1.00	0.80	0.80	0.80	**0.5**	1.70	1.00	1.70	1.00	0.39	**1.1**
B	*Score*	0%	0%	0%	0%	0%	0%		100%	0%	90%	100%	0%	
	Mult	1.40	1.30	1.30	1.10	1.20	1.10	**3.4**	1.00	1.00	1.10	1.00	4.00	**4.4**
C	*Score*	100%	0%	0%	0%	0%	0%		100%	0%	10%	100%	35%	
	Mult	1.00	1.30	1.30	1.10	1.20	1.10	**2.5**	1.00	1.00	1.90	1.00	2.67	**5.1**
D	*Score*	100%	100%	100%	100%	100%	100%		100%	0%	0%	100%	75%	
	Mult	1.00	1.00	1.00	0.80	0.80	0.80	**0.5**	1.00	1.00	2.00	1.00	1.15	**2.3**
E	*Score*	100%	80%	100%	0%	0%	100%		100%	0%	80%	100%	90%	
	Mult	1.00	1.06	1.00	1.10	1.20	0.80	**1.1**	1.00	1.00	1.20	1.00	0.58	**0.7**
F	*Score*	100%	100%	50%	100%	100%	100%		100%	0%	100%	100%	0%	
	Mult	1.00	1.00	1.15	0.80	0.80	0.80	**0.6**	1.00	1.00	1.00	1.00	4.00	**4.0**
G	*Score*	100%	100%	50%	100%	100%	100%		100%	0%	100%	100%	90%	
	Mult	1.00	1.00	1.15	0.80	0.80	0.80	**0.6**	1.00	1.00	1.00	1.00	0.58	**0.6**
H	*Score*	100%	100%	100%	100%	100%	100%		100%	100%	100%	100%	90%	
	Mult	1.00	1.00	1.00	0.80	0.80	0.80	**0.5**	1.00	0.70	1.00	1.00	0.58	**0.4**
I	*Score*	100%	100%	100%	100%	100%	100%		100%	0%	100%	100%	95%	
	Mult	1.00	1.00	1.00	0.80	0.80	0.80	**0.5**	1.00	1.00	1.00	1.00	0.39	**0.4**
J	*Score*	100%	100%	100%	0%	100%	100%		100%	0%	100%	100%	0%	
	Mult	1.00	1.00	1.00	1.10	0.80	0.80	**0.7**	1.00	1.00	1.00	1.00	4.00	**4.0**
K	*Score*	25%	25%	100%	25%	100%	40%		80%	0%	25%	100%	75%	
	Mult	1.30	1.23	1.00	1.03	0.80	0.98	**1.3**	1.20	1.00	1.75	1.00	1.15	**2.4**
L	*Score*	100%	100%	100%	100%	100%	40%		80%	0%	50%	100%	75%	
	Mult	1.00	1.00	1.00	0.80	0.80	0.98	**0.6**	1.20	1.00	1.50	1.00	1.15	**2.1**
M	*Score*	100%	80%	100%	90%	50%	50%		100%	0%	50%	100%	80%	
	Mult	1.00	1.06	1.00	0.83	1.00	0.95	**0.8**	1.00	1.00	1.50	1.00	0.96	**1.4**
N	*Score*	100%	80%	100%	90%	100%	50%		100%	0%	50%	100%	80%	
	Mult	1.00	1.06	1.00	0.83	0.80	0.95	**0.7**	1.00	1.00	1.50	1.00	0.96	**1.4**
O	*Score*	100%	100%	100%	40%	20%	100%		100%	0%	100%	100%	100%	
	Mult	1.00	1.00	1.00	0.98	1.12	0.80	**0.9**	1.00	1.00	1.00	1.00	0.20	**0.2**
P	*Score*	100%	100%	100%	40%	20%	100%		100%	0%	20%	100%	100%	
	Mult	1.00	1.00	1.00	0.98	1.12	0.80	**0.9**	1.00	1.00	1.80	1.00	0.20	**0.4**
Q	*Score*	100%	100%	100%	40%	20%	100%		100%	0%	20%	100%	80%	
	Mult	1.00	1.00	1.00	0.98	1.12	0.80	**0.9**	1.00	1.00	1.80	1.00	0.96	**1.7**
Average								**1.0**						**1.9**
Min								0.5						0.2
Max								3.4						5.1
Ratio								7						26

To find the multiplier, a score of 0% corresponds to a multiplier of 1.3, and a score of 100% corresponds to a multiplier of 1.0. Understanding the dynamics between the plant and the grid is a key component of each of the LERs discussed above.

c. Has the timing of the plant voltage requirements been coordinated with the power system's ability to provide that voltage post-contingency? In some cases, starting of large motors during load sequencing from the preferred power supply may cause the voltage to fall into the drop out zone of the degraded grid relays. In this case, it is essential to determine that the voltage will recover above the reset point of the relay within the time out period of the relay. Similarly, analysis of the grid supplied switchyard post-contingency voltage may assume that generator voltage controllers or automatically switched inductors have had time to operate. Dynamic analysis is required to determine both the motor acceleration time, and the voltage recovery time from the grid. This determination is critical to ensure that the voltage recovers in time to adequately support the safety related motors. If this is not coordinated, there is a possibility that safety related motors may stall when starting, or that the degraded grid relay may time out during a load sequencing and separate the plant from the preferred power supply. A thorough analysis will provide tolerances for degraded voltage relay drift and setpoint error, as well as a buffer between the expected recovery voltage and reset voltage, and recovery time and relay time out period.

To find the multiplier, a score of 0% corresponds to a multiplier of 1.3, and a score of 100% corresponds to a multiplier of 1.0. Relay time out is a factor in at least one LER (Duane Arnold), and the timing of the voltage is just as essential as the level of the voltage.

d. Is the geographic scope of real-time data collection, control, and system operations sufficient to address all nuclear plant off-site power reliability concerns? System disturbances can propagate over large distances on the interconnected power system. The increasing number of long distance transactions increases this vulnerability. Either the control area operator, the regional security coordinator, or both must have access to real-time data over a broad geographic region to assure system security. Evaluation of regional operating parameters can reduce the likelihood of LOOP, so a multiplier of less than 1 is possible.

   To find the multiplier, a score of 0% corresponds to a multiplier of 1.1, and a score of 100% corresponds to a multiplier of 0.8. The geographic scope of data collection was a major factor in the WSCC events of 1996.

e. Are real-time data tools, including state estimation and on-line contingency analysis, used by the control area operator, adjacent control areas (if their operation can influence the nuclear plants voltage), and the regional security coordinator? It is important to study expected conditions on the power system but this is not sufficient. Because of the nearly infinite range of possible operating conditions the power system can find itself in it is difficult to assure that acceptable post-contingency support will be provided the nuclear plant without these tools. Since use of real time tools can reduce the likelihood of LOOP, a multiplier of less than 1 is possible.

   To find the multiplier, a score of 0% corresponds to a multiplier of 1.2, and a score of 100% corresponds to a multiplier of 0.8. Real time data analysis is playing an increasingly important role with the large numbers of generators, transmission providers and ancillary service providers being produced by deregulation. It plays a key role in lowering the frequency of LOOP, and receives the maximum multiplier range.

f. Are system operators well trained in nuclear plant off-site power requirements and methods/procedures to assure adequacy of off-site supply? Availability of a training simulator is evidence of training commitment. When system operators are trained and have practiced responding to contingencies involving nuclear plant voltage, they are more likely to make the correct decision when an actual event occurs, so a multiplier of less than 1 is possible.

   To find the multiplier, a score of 0% corresponds to a multiplier of 1.1, and a score of 100% corresponds to a multiplier of 0.8. Training, although not mentioned in the above reports, is always a key factor in ensuring appropriate action during emergency scenarios.

2. Area Blackout Recovery Time Multiplier

Area blackout power restoration time multipliers: For each of the following criteria, the plant is subjectively scored on a scale of 0 to 100%. A perfect score is 100%, and a complete deficiency is 0%. The criteria multipliers are then determined from these scores using the values given for each criteria below. All of the individual criteria multipliers are then multiplied together to find the total recovery time in hours. No national average recovery time is used because criteria e. below is the estimated number of hours to restore power to the nuclear plant assuming all other factors are optimized.

a. Does the control area operator have a plan in place with instructions for restoring off-site power to the nuclear plant? This plan should specify the black start units to start first, the first transmission lines to be energized, precautions to ensure that the transmission lines are ready for energization, what requirements must be met before the preferred power supply can be reconnected, etc. (While system conditions cannot be predicted and plans must remain flexible, the plan should include information on the capabilities and limitations of units to energize sections of the transmission system, synchronization locations, etc.) Lack of a plan may double the restoration time.

   To find the multiplier, a score of 0% corresponds to a multiplier of 2.0, and a score of 100% corresponds to a multiplier of 1.0.

b. Is there a regional or control area automatic restoration system (e.g. Duke's Express Transmission System)? This system would automatically clear transmission lines to isolate a "backbone" transmission grid, start black start units, and energize the backbone. Very few utilities have this type of automatic restoration system, but those who do can significantly reduce their recovery time.

To find the multiplier, a score of 0% corresponds to a multiplier of 1.0, and a score of 100% corresponds to a multiplier of 0.7.

c. Is the regional blackout plan tested or exercised regularly to provide system and plant operator training and to verify the effectiveness of the plan? (This does not necessarily require de-energizing portions of the transmission system.) The plan should be tested in segments to ensure that the black start equipment does perform properly. If simulation is not performed, the restoration time may be significantly longer than planned.

   To find the multiplier, a score of 0% corresponds to a multiplier of 2.0, and a score of 100% corresponds to a multiplier of 1.0.

d. Are their multiple alternative black start resources owned by or under firm contract with the nuclear plant control area operator to restore off-site power to the nuclear plant? Are the black start generators tested under the regional black out test plan? Typically, plants have several alternate black start generators available. In cases where there are none nearby, or if there are none under firm contract, restoration time may be significantly longer than planned.

   To find the multiplier, a score of 0% corresponds to a multiplier of 2.0, and a score of 100% corresponds to a multiplier of 1.0.

e. Are local black start capable units available to directly supply power to the nuclear plant (without the need to start other generators)? A distant black start unit usually is not capable of directly supplying power to the nuclear plant because of the reactive power required to charge the transmission line. Intermediary units may need to be restored to service before off-site power is provided to the nuclear unit.

The overall area blackout recovery time multiplier, unlike the LOOP overall multiplier, is the estimated number of hours for restoring power to the nuclear plant assuming all other factors are optimized. This time was usually provided by the utility during the load dispatch center visit.

Different LOOP frequency versus duration curves can be developed by shifting the historical curve (i.e., NUREG-1032, Figure 3.2) according to the multiplier factors determined through the utility interviews (Table A.1). Figure A.1 shows the best case scenario (Plants A, D, H, and J) and worst case scenario (Plant B) for the subject curve using the LOOP Frequency criteria.

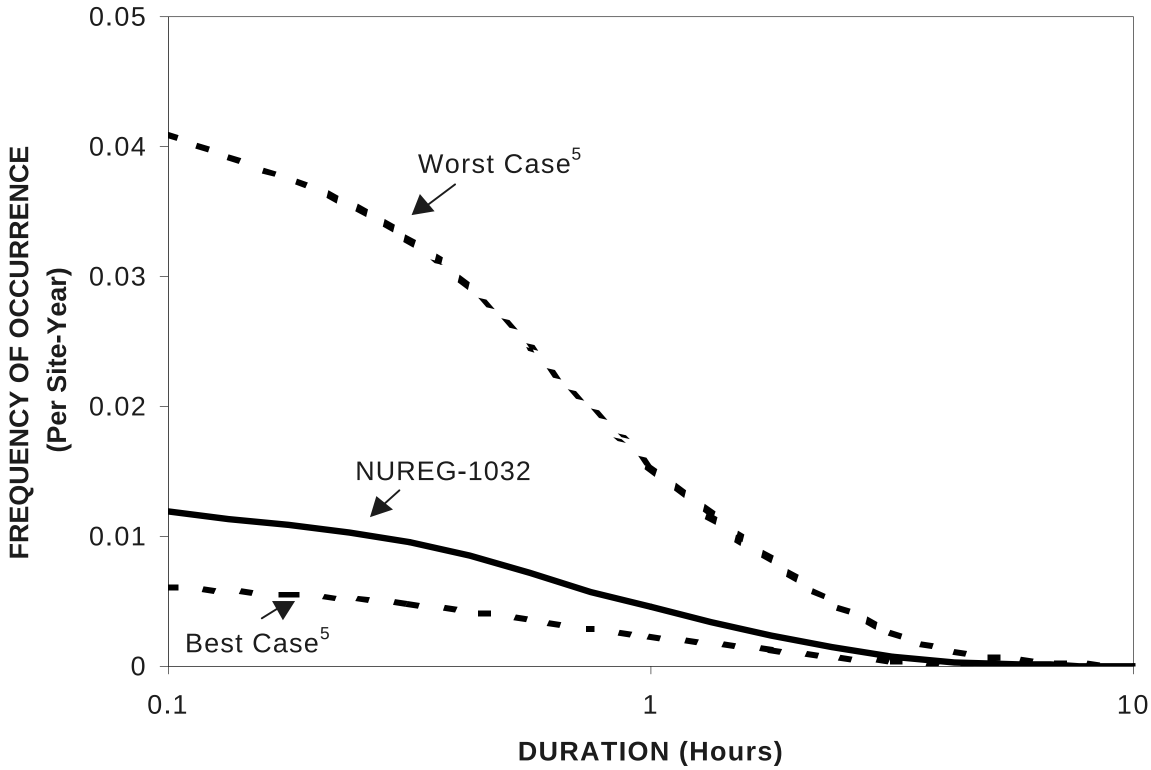

Figure A.1 Frequency of grid related loss-of-offsite power events exceeding specified durations, derived from NUREG-1032 Figure 3.2, adjusted with the ORNL plant specific LOOP multipliers.

NUREG-1032 provided historical LOOP event frequencies and time to recovery from those events arising from various causes. This study provided background information to the project team regarding typical LOOP durations and frequencies which was used as a basis to estimate area blackout recovery time multipliers in this report. These differences range from 0.2 to 5.1 hours, and warrant further investigation. While all control areas visited for this report stated that their nuclear plant received the highest priority in the control area restoration plan significant differences were found in the expected recovery times. However, no compelling data was found to indicate, that for average values, the historical LOOP frequency versus duration curve has been significantly affected to date. In the longer run, commercial pressures should force structural changes that would be assumed to increase reliability.

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[5] These are based upon the plants listed in Table A.1

Appendix B

A Case Study of North American Electric Reliability Council (NERC) Disturbance No. 10 in 1997

NERC Disturbance No. 10 in 1997 may be found on the Internet at http://www.nerc.com/dawg/database.html/.

Appendix C

Protocol Used During Control Center Visits

Assessment Protocol and Data Collection Regarding Electric Power Grid Performance: Evaluations of Impact to Nuclear Power Plant Operations, Forecasting, Emergency Conditions, and Recovery Relative to Offsite Power Disturbances

Meeting Attendance:

General

1. How are generation control, transmission control, and commercial transactions organized for this control area?

2. What is the relationship between the nuclear plant, the control area, and the regional security coordinator?

Nuclear Plant

3. How have the nuclear plant's requirements for adequate off-site power (voltage, frequency, time) been determined?
   a Does the analysis determine the minimum required switchyard voltage considering the voltage drop through the entire auxiliary power system before reaching the motor terminals?
   b Does the analysis consider motor starting?
   c Does the analysis consider the plant generator tripping and the time to accelerate each load block if the loads are sequenced rather than block started from the preferred power supply?

4. Are these time and voltage requirements reflected in the degraded voltage relaying scheme?
   a With acceptable buffers (margin) between the relay setpoints and the transmission operations procedure?
   b Is the setting of the degraded grid relay time delay coordinated with the time required to restore voltage above the reset voltage of the relay when loads are being sequenced?

5. Have the plant's voltage and frequency requirements been formally documented?

6. Is there a formal procedure for updating these voltage and frequency requirements? What triggers updating?

7. Who drives the determination of the voltage and frequency schedules at the nuclear plant switchyard? The nuclear plant? The transmission system?

8. Do voltage and frequency schedules fully capture off-site power reliability concerns for the nuclear plant? If not, what else is required?

9. Have the worst case design basis events postulated in the FSAR (for example, two unit trip coincident with LOCA on one unit) been passed to each of the parties for inclusion in their analysis?

10. Have all transmission system conditions, connections, generation support, etc., necessary to meet the nuclear plant's requirements been clearly identified in the Technical Specifications?

11. Have Limiting Conditions for Operation (LCO's) been defined for situations where the requirements are not met?

12. Does the nuclear plant have a procedure to declare when a plant Technical Specification Action is required based upon inoperability of the preferred power supply?

13. How is the operational boundary or interface between the nuclear plant and the transmission system defined?

a What are the terms of definition?
b What overlap exists in relaying?
c Is the interface the same for both operations and maintenance?

Studies

14. Have the nuclear plant's voltage and frequency requirements been formally documented? Are they part of the formal transmission system study requirements?

15. What analysis (load flow, transient stability, ...) has been performed to ensure adequacy of off-site power to the nuclear plant?

16. Have all credible operating conditions and contingencies been studied?
    a loss of the nuclear plant and its VAR support?
    b for other local and remote generation
    c for the local and remote transmission system configurations
    d for load conditions
    e for the interconnection and reliability council (through system power flow i.e., through flow power or third party transactions, for example)

17. What are the criteria for determining the conditions and contingencies studied?
    a Are these formally documented?
    b Are these verified against historic system performance?

18. How often are the analyses updated?

19. How is the time dependent nature of the voltage and frequency requirements of the nuclear plant accommodated in the analysis (allowable recovery time from degraded voltage for example)?

20. Have the contingencies chosen for analysis been coordinated with the nuclear plant requirements to assure that the analysis matches the worst case design requirements for the plant?

21. What automatic control actions (switching of capacitor banks or load tap changer operation, for example) were assumed in the analysis?

22. Are statistics concerning event frequency used in determining the contingencies studied?

23. Are there transmission system load and power transfer conditions which will cause the nuclear plant switchyard voltage to move down or up after the plant is tripped? If so, how much, (1 or 2 %, or 5%)? Does local generation support have to be provided to prevent the voltage from dropping post trip?

Operating Procedures

24. Have the nuclear plant's voltage and frequency requirements been formally documented? Are they part of the formal transmission system operating procedures?

25. Have the study results been translated into operating procedures and guidelines?
    a For the system operator? For other generating stations?
    b Have these been formally documented?

26. Have the procedures and guidelines been evaluated to determine whether they are achievable? For example, are there any actions that must be taken within the voltage recovery time to prevent separation from offsite power?

27. Have formal procedures been established for notifying the nuclear plant operators when the local transmission system

enters into a degraded condition?
a What conditions require notification?
b Who holds the responsibility for initiating notification?
c Who holds the responsibility for ensuring that the plant is not operated outside the set of conditions?

28. Have formal procedures been established to notify operators of other critical facilities (other required generators, critical loads, transmission facilities, etc.) when the local transmission system enters into a condition where off-site power supply to the nuclear plant could be compromised?
    a What conditions require notification?
    b Have plant operators been trained on these procedures?
    c Who holds the responsibility for initiating notification?

29. What monitoring and on line predictors are in place to assure that power system conditions are acceptable from the perspective of adequacy of off-site power supply to nuclear facilities?
    a What real-time data (voltages, flows, …) is monitored by the control area? The regional security coordinator? What is the geographic scope of the real-time monitoring?
    b Is a state estimator or on-line contingency analysis used by the control area and the regional security coordinator to examine potential contingencies?
    c Does the control area tag the power transfer across the transmission lines, or can power flow be unaccounted for?
    d Does monitoring change under contingency conditions?

30. What mechanisms are in place to assure that facilities, such as other generators, that are needed to adjust operations to accommodate adequate and reliable off-site power will do so?
    a Contractual?
    b Regulatory (FERC, NRC, state regulators, etc.)?
    c NERC or regional reliability council rules?

31. Who has responsibility for taking action (ISO, control area operator, etc.)?
    a What gives them the authority to take action?

32. How does maintenance of nuclear plant off-site voltage and frequency capabilities compare with other system operator responsibilities (such as maintaining supply to hospitals and other critical loads, maintaining the viability of the transmission system, etc.)?
    a under normal conditions?
    b under contingency conditions?
    c are these responsibilities quantified or listed in order?

33. Who holds the responsibility for the transmission system improvements based on growth or operational forecasts?

Restoration

34. In the event of a Grid or Area Blackout, do power system restoration analysis and plans consider the timing of restoration of off-site power to the nuclear plant and what actions must be taken to ensure that the voltage and frequency requirements are not compromised after restoration?
    a Is there a formal procedure for restoring the grid after a control area or regional blackout has occurred?
    b Is there a regional or control area black start automatic restoration circuitry (e.g. Duke’s Express Transmission System)?

    c What priority does the nuclear plant have in the power system restoration plans?

35. How long might it take to restore offsite power to the nuclear plant following an area or regional blackout?
    a Has the black start procedure been practiced by the control area and the generating stations in a formal drill?

36. Are there additional plants that have to be started before the circuit to the nuclear plant can be reenergized? Are these

under formal regional control? Can these plants be started in parallel, or do they have to be done sequentially? If sequentially, how long will this take?

37. Are there any non-utility generators that have to black start as part of the plan? Is there a formally contracted black start test requirement.

38. Based upon the utility's historical information, how long has it taken to restore offsite power to the nuclear power plant? What type of reliability data is available on offsite power to nuclear power plants?

39. Based upon historic performance, how long has it taken to restore off-site power from a degraded condition?

Statistics

40. How are voltage and frequency excursion events recorded?
    - a At the nuclear plant?
    - b At the control area?
    - c At the regional reliability council and at NERC?
    - d Are near-misses recorded (including being one contingency away from a problem though actual voltage and frequency may have been acceptable)?
    - e Are trends monitored?
    - f How many times has the switchyard voltage reached the minimum allowable level? Is historic data available?

41. What is the probability of loss of off-site power?

42. How do you know?

Restructuring

43. Has/will restructuring of the electric power industry impact specification of adequacy and reliability of nuclear plant off-site power requirements?

44. Will restructuring impact the frequency of inadequate off-site power events?

45. Will restructuring impact the time required for the system to restore off-site power after it is degraded or lost?

46. Will restructuring impact the frequency of brown-outs or black-outs to customers?

47. Has/will restructuring of the electric power industry impacted analysis requirements or the way analysis is performed or reported?

48. Are there costs associated with assuring the adequacy and reliability of nuclear plant off-site power requirements?

49. Will the SBO assumptions need to be revised because of restructuring?

50. Are system operators being trained and certified?

Concerns

Appendix D

Master Definitions Supplement

This *Master Definitions Supplement* is a reduced set taken from the full NERC glossary available on the Internet at: http://www.nerc.com/glossary/. The document "provides a list of terms and their definitions describing various aspects of interconnected electric systems planning and operation from a reliability perspective. All parties using or having interest in the interconnected electric systems in North America are encouraged to use this Glossary to provide consistency in terminology and to improve understanding and communications about electric system planning and operations. Use of this Glossary also will help minimize confusion regarding the meaning of these terms."

Note that these are the NERC definitions for terms as of August 1996. There is some controversy over exact definitions for a few of the terms under restructuring. For example, under Reserves NERC defines Operating Reserve as "That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection." This definition mixes security functions (regulation, equipment forced outages, and local area protection) with adequacy functions (load forecasting error and equipment scheduled outages). Many (possibly including FERC) now feel that this is inappropriate and Operating Reserves should only address security concerns. None-the-less, the full NERC glossary is an excellent resource with few controversial enteries.

Access — The contracted right to use an electrical system to transfer electrical energy.

Adequacy — See Reliability.

Adjacent System or Adjacent Control Area — Any system or Control Area either directly interconnected with or electrically close to (so as to be significantly affected by the existence of) another system or Control Area.

Ancillary Services — Interconnected Operations Services identified by the U.S. Federal Energy Regulatory Commission (Order No. 888 issued April 24, 1996) as necessary to effect a transfer of electricity between purchasing and selling entities and which a transmission provider must include in an open access transmission tariff. See also Interconnected Operations Services.

Energy Imbalance Service — Provides energy correction for any hourly mismatch between a transmission customer's energy supply and the demand served.

Operating Reserve: Spinning Reserve Service — Provides additional capacity from electricity generators that are on-line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur.

Operating Reserve: Supplemental Reserve Service — Provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes.

Reactive Supply and Voltage Control From Generating Sources Service — Provides reactive supply through changes to generator reactive output to maintain transmission line voltage and facilitate electricity transfers.

Regulation and Frequency Response Service — Provides for following the moment-to-moment variations in the demand or supply in a Control Area and maintaining scheduled Interconnection frequency.

Scheduling, System Control, and Dispatch Service — Provides for a) scheduling, b) confirming and implementing an interchange schedule with other Control Areas, including intermediary Control Areas providing transmission service, and c) ensuring operational security during the interchange transaction.

Area Control Error — The instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias.

Automatic Generation Control (AGC) — Equipment that automatically adjusts a Control Area's generation to maintain its interchange schedule plus its share of frequency regulation.

Available Transfer Capability (ATC) — A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

Backup Power — Power provided by contract to a customer when that customer's normal source of power is not available.

Backup Supply Service — See Interconnected Operations Services.

Blackstart Capability — The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.

Broker — A third party who establishes a transaction between a seller and a purchaser. A Broker does not take title to capacity or energy.

Bulk Electric System — A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system.

Capacity — The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.

Cascading — The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Cogeneration — Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.

Combined Cycle — An electric generating technology in which electricity and process steam is produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Commonly Owned Unit — A generating unit whose capacity is owned or leased and divided among two or more entities. Synonym: Jointly Owned Unit.

Contingency — The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Contract Path — A specific contiguous electrical path from a Point of Receipt to a Point of Delivery for which transfer rights have been contracted.

Control Area — An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Interconnection.

Curtailability — The right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist.

Curtailment — A reduction in the scheduled capacity or energy delivery.

Demand — The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.

Demand-Side Management — The term for all activities or programs undertaken by an electric system or its customers to influence the amount or timing of electricity use.

Dispatchable Generation — Generation available physically or contractually to respond to changes in system demand or to respond to transmission security constraints.

Disturbance — An unplanned event that produces an abnormal system condition.

Dynamic Rating — The process that allows a system element rating to vary with the changing environmental conditions in which the element is located.

Diversity Factor — The ratio of the sum of the coincident maximum demands of two or more loads to their noncoincident maximum demand for the same period.

Dynamic Schedule — A telemetered reading or value that is updated in real time and used as a schedule in the Automatic Generation Control/Area Control Error equation and the integrated value of which is treated as a schedule. Commonly used for “scheduling” commonly owned generation or remote load to or from another Control Area.

Economic Dispatch — The allocation of demand to individual generating units on line to effect the most economical production of electricity.

Electrical Energy — The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).

Firm Energy — Electrical Energy backed by capacity, interruptible only on conditions as agreed upon by contract, system reliability constraints, or emergency conditions and where the supporting reserve is supplied by the seller.

Nonfirm Energy — Electrical Energy that may be interrupted by either the provider or the receiver of the energy. Nonfirm Energy may also be interrupted to maintain system reliability of third- party Transmission Providers.

Emergency Energy — Electrical Energy purchased by a member system whenever an event on that system causes insufficient Operating Capability to cover its own demand requirement.

Economy Energy — Electrical Energy produced and supplied from a more economical source in one system and substituted for that being produced or capable of being produced by a less economical source in another system.

Off-Peak Energy — Electrical Energy supplied during a period of relatively low system demands as specified by the supplier.

On-Peak Energy — Electrical Energy supplied during a period of relatively high system demands as specified by the supplier.

Electric System Losses — Total electric energy losses in the electric system. The losses consist of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to heating of transmission and distribution elements.

Element — Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section. See Rating, System Element Rating.

Limiting Element — The element that is either operating at its appropriate rating or would be following the limiting contingency and, as a result, establishes a system limit.

Emergency — Any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the electric system.

Fault — An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.

Forecast — Predicted demand for electric power. A forecast may be short term (e.g., 15 minutes) for system operation purposes, long-term (e.g., five to 20 years) for generation planning purposes, or for any range in between. A forecast may include peak demand, energy, reactive power, or demand profile. A forecast may be made for total system demand, transmission loading, substation/feeder loading, individual customer demand, or appliance demand.

Frequency

Frequency Bias — A value, usually given in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.

Frequency Deviation — A departure from scheduled frequency.

Frequency Error — The difference between actual system frequency and the scheduled system frequency.

Frequency Regulation — The ability of a Control Area to assist the interconnected system in maintaining scheduled frequency. This assistance can include both turbine governor response and automatic generation control.

Frequency Response (Equipment) — The ability of a system or elements of the system to react or respond to a change in system frequency.

Frequency Response (System) — The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

Scheduled Frequency — 60.0 Hertz, except during a time correction.

Generation (Electricity) — The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatthours (kWh) or megawatthours (MWh).

Host Control Area (HCA) — 1. A Control Area that confirms and implements scheduled Interchange for a Transmission Customer that operates generation or serves customers directly within the Control Area's metered boundaries. 2. The Control Area within whose metered boundaries a commonly owned unit or terminal is physically located.

Imbalance — A condition where the generation and interchange schedules do not match demand.

Inadvertent Interchange or Inadvertent — The difference between a Control Area's net actual interchange and net scheduled interchange.

Incremental Energy Cost — The additional cost that would be incurred by producing or purchasing the next available unit of electrical energy above the current base cost.

Incremental Heat Rate — The amount of additional heat that must be added to a thermal generating unit at a given loading to produce an additional unit of output. It is usually expressed in British thermal units per kilowatt hour (Btu/kWh) of output.

Independent Power Producers (IPP) — As used in NERC reference documents and reports, any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators who sell electricity.

Interchange — Electric power or energy that flows from one entity to another.

Actual Interchange — Metered electric power that flows from one entity to another.

Scheduled Interchange — Electric power scheduled to flow between entities, usually the net of all sales, purchases, and wheeling transactions between those areas at a given time.

Interconnected Operations Services (IOS) — Services that transmission providers may offer voluntarily to a transmission customer under Federal Energy Regulatory Commission Order No. 888 in addition to Ancillary Services. See also Ancillary Services.

Backup Supply Service — Provides capacity and energy to a transmission customer, as needed, to replace the loss of its generation sources and to cover that portion of demand that exceeds the generation supply for more than a short time.

Dynamic Scheduling Service — Provides the metering, telemetering, computer software, hardware, communications, engineering, and administration required to *electronically* move a transmission customer's generation or demand out of the Control Area to which it is physically connected and into a different Control Area.

Real Power Loss Service — Compensates for losses incurred by the Host Control Area(s) as a result of the interchange transaction for a transmission customer. Federal Energy Regulatory Commission's Order No. 888 requires that the transmission customer's service agreement with the Transmission Provider identify the entity responsible for supplying real power loss.

Restoration Service — Provides an offsite source of power to enable a Host Control Area to restore its system and a transmission customer to start its generating units or restore service to its customers if local power is not available.

Interconnected System — A system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

Interconnection — When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT, Québec, and Alaska. When not capitalized, the facilities that connect two systems or Control Areas. Additionally, an interconnection refers to the facilities that connect a nonutility generator to a Control Area or system.

Interface — The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.

Intermediary Control Area — A Control Area that has connecting facilities in the scheduling path between the sending and receiving Control Areas and has operating agreements that establish the conditions for the use of such facilities.

Island — A portion of a power system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system elements.

Joint Unit Control — Automatic generation control of a generating unit by two or more entities.

Lambda — A term commonly given to the incremental cost that solves the economic dispatch calculation. It represents the cost of the next kilowatt hour that could be produced from dispatchable units on the system.

Load — An end-use device or customer that receives power from the electric system. Load should not be confused with Demand, which is the measure of power that a load receives or requires. See Demand.

Load Cycle — The normal pattern of demand over a specified time period associated with a device or circuit.

Load Following — An electric system's process of regulating its generation to follow the changes in its customers' demand.

Load Shedding — The process of deliberately removing (either manually or automatically) preselected customer demand from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Loop Flows — See Parallel Path Flows.

Margin — The difference between net capacity resources and net internal demand. Margin is usually expressed in megawatts (MW).

Marketer — An entity that has the authority to take title to electrical power generated by itself or another entity and remarket that power at market-based rates.

Metered Value — A measured electrical quantity that may be observed through telemetering, supervisory control and data acquisition (SCADA), or other means.

Metering — The methods of applying devices that measure and register the amount and direction of electrical quantities with respect to time.

Must-Run Generation — Generation designated to operate at a specific level and not available for dispatch. See Dispatchable Generation.

North American Electric Reliability Council (NERC) — A not-for-profit company formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of ten Regional Reliability Councils and one Affiliate whose members account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The members of these Councils are from all segments of the electricity supply industry — investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers. The NERC Regions are: East Central Area Reliability Coordination Agreement (ECAR); Electric Reliability Council of Texas (ERCOT); Florida Reliability Coordinating Council (FRCC); Mid-Atlantic Area Council (MAAC); Mid-America Interconnected Network (MAIN); Mid-Continent Area Power Pool (MAPP); Northeast Power Coordinating Council (NPCC); Southeastern Electric Reliability Council (SERC); Southwest Power Pool (SPP); Western Systems Coordinating Council (WSCC); and Alaskan Systems Coordination Council (ASCC, Affiliate).

OASIS (Open -Access Same-Time Information System) — An electronic posting system for transmission access data that allows all Transmission Customers to view the data simultaneously.

Off Peak — Those hours or other periods of lower electrical demand.

On Peak — Those hours or other periods of higher electrical demand.

Operating Criteria — The fundamental principles of reliable interconnected systems operation.

Operating Guides — Operating practices that a Control Area or systems functioning as part of a Control Area may wish to consider. The application of Guides is optional and may vary among Control Areas.

Operating Instructions — Training documents, appendices, and other documents that explain the Criteria, Requirements, Standards, and Guides.

Operating Policies — The doctrine developed for interconnected systems operation. This doctrine consists of Criteria, Standards, Requirements, Guides, and instructions and apply to all Control Areas.

Operating Procedures — A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Automatic Operating Systems — Special protection systems, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of system operators.

Normal (Precontingency) Operating Procedures — Operating procedures that are normally invoked by the system operator to alleviate potential facility overloads or other potential system problems in anticipation of a contingency.

Postcontingency Operating Procedures — Operating procedures that may be invoked by the system operator to mitigate or alleviate system problems after a contingency has occurred.

Operating Requirements — Obligations of a Control Area and systems functioning as part of a Control Area.

Operating Reserve: Spinning Reserve Service — See Ancillary Services.

Operating Reserve: Supplemental Reserve Service — See Ancillary Services.

Operating Standards — The obligations of a Control Area and systems functioning as part of a Control Area that are measurable. A Standard may specify monitoring and surveys for compliance.

Operating Transmission Limit — The maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient performance criteria or, (c) postcontingency loading and voltage criteria.

Outage

Forced Outage — The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure.

Forced Outage Rate — The hours a generating unit, transmission line, or other facility is removed from service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.

Maintenance Outage — The removal of equipment from service availability to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.

Planned Outage — Removing the equipment from service availability for inspection and/or general overhaul of one or more major equipment groups. This outage usually is scheduled well in advance.

Parallel Path Flows — The difference between the scheduled and actual power flow, assuming zero inadvertent interchange, on a given transmission path. Synonyms: Loop Flows, Unscheduled Power Flows, and Circulating Power Flows.

Planning (System) — The process by which the performance of the electric system is evaluated and future changes and additions to the bulk electric systems are determined.

Planning Guides — Good planning practices and considerations that Regions, subregions, power pools, or individual systems should follow. The application of Planning Guides may vary to match local conditions and individual system requirements.

Planning Policies — The framework for the reliability of interconnected bulk electric supply in terms of responsibilities for the development of and conformance to NERC Planning Principles and Guides and Regional planning criteria or guides, and NERC and Regional issue resolution processes.

Planning Principles — The fundamental characteristics of reliable interconnected bulk electric systems and the tenets for planning them.

Planning Procedures — An explanation of how the Planning Policies are addressed and implemented by the NERC Engineering Committee, its subgroups, and the Regional Councils to achieve bulk electric system reliability.

Power

Apparent Power — The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Reactive Power — The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).

Real Power — The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Power Flow Program — A computerized algorithm that simulates the behavior of the electric system under a given set of conditions.

Power Pool — Two or more interconnected electric systems planned and operated to supply power for their combined demand requirements.

Rating — The operational limits of an electric system, facility, or element under a set of specified conditions.

Continuous Rating — The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand indefinitely without loss of equipment life.

Normal Rating — The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating — The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units, that a system, facility, or element can support or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Real-Time Operations — The instantaneous operations of a power system as opposed to those operations that are simulated.

Region — One of the NERC Regional Reliability Councils or Affiliate.

Regional Reliability Council — One of ten Electric Reliability Councils that form the North American Electric Reliability Council (NERC).

Regional Transmission Group (RTG) — Voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning and expansion and use on a regional and interregional basis.

Reliability — The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — Adequacy and Security.

Adequacy — The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Reliability Criteria — Principles used to design, plan, operate, and assess the actual or projected reliability of an electric system.

Reserve

Operating Reserve — That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection.

Spinning Reserve — Unloaded generation, which is synchronized and ready to serve additional demand. It consists of Regulating Reserve and Contingency Reserve.

Regulating Reserve — An amount of spinning reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

Contingency Reserve — An additional amount of operating reserve sufficient to reduce Area Control Error to zero in ten minutes following loss of generating capacity, which would result from the most severe single contingency. At least 50% of this operating reserve shall be Spinning Reserve, which will automatically respond to frequency deviation.

Nonspinning Reserve — That operating reserve not connected to the system but capable of serving demand within a specific time, or Interruptible Demand that can be removed from the system in a specified time. Interruptible Demand may be included in the Nonspinning Reserve provided that it can be removed from service within ten minutes.

Planning Reserve — The difference between a Control Area's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Schedule — An agreed-upon transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the contracting parties and the Control Area(s) involved in the transaction.

Security — See Reliability.

Single Contingency — The sudden, unexpected failure or outage of a system facility(s) or element(s) (generating unit, transmission line, transformer, etc.). Elements removed from service as part of the operation of a remedial action scheme are considered part of a single contingency.

Stability — The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

Substation — A facility for switching electrical elements, transforming voltage, regulating power, or metering.

Supervisory Control — A form of remote control comprising an arrangement for the selective control of remotely located facilities by an electrical means over one or more communications media.

Supervisory Control and Data Acquisition (SCADA) — A system of remote control and telemetry used to monitor and control the electric system.

Surge — A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.

Synchronize — The process of connecting two previously separated alternating current apparatuses after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).

System — An interconnected combination of generation, transmission, and distribution components comprising an electric utility, an electric utility and independent power producer(s) (IPP), or group of utilities and IPP(s).

System Operator — An individual at an electric system control center whose responsibility it is to monitor and control that electric system in real time.

Thermal Rating — The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

Tie Line — A circuit connecting two or more Control Areas or systems of an electric system.

Time Error — An accumulated time difference between Control Area system time and the time standard. Time error is caused by a deviation in Interconnection frequency from 60.0 Hertz.

Time Error Correction — An offset to the Interconnection's scheduled frequency to correct for the time error accumulated on electric clocks.

Total Transfer Capability (TTC) — The amount of electric power that can be transferred over the interconnected transmission network in a *reliable* manner.

Transmission — An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Constraints — Limitations on a transmission line or element that may be reached during normal or contingency system operations.

Transmission Provider — Any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce.

Unit Commitment — The process of determining which generators should be operated each day to meet the daily demand of the system.

Voltage Collapse — An event that occurs when an electric system does not have adequate reactive support to maintain voltage stability. Voltage Collapse may result in outage of system elements and may include interruption in service to customers.

Voltage Control — The control of transmission voltage through adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

Voltage Limits

Normal Voltage Limits **—** The operating voltage range on the interconnected systems that is acceptable on a sustained basis.

Emergency Voltage Limits — The operating voltage range on the interconnected systems that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.

Voltage Reduction — A means to reduce the demand by lowering the customer's voltage.

Voltage Stability — The condition of an electric system in which the sustained voltage level is controllable and within predetermined limits.

Wheeling — The contracted use of electrical facilities of one or more entities to transmit electricity for another entity.