ADAMS ACCESSION NUMBER ML003743741

THE EFFECTS OF DEREGULATION OF THE ELECTRIC POWER INDUSTRY ON THE NUCLEAR PLANT OFFSITE POWER SYSTEM: AN EVALUATION

Prepared by:
William S. Raughley

Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission

ABSTRACT

This report presents an evaluation of the impact of electric power industry deregulation on grid reliability and reactor safety. Deregulation has the potential to challenge operating and reliability limits on the transmission system and could affect the reliability of the electric power system and the offsite power to nuclear plants. The report describes the offsite power system, discusses the principal criteria for evaluating the effects of deregulation on the nuclear plant offsite power system, and presents a review of various staff risk-informed and engineering-based initiatives to evaluate deregulation issues related to the nuclear plant offsite power system. This report provides the basis for the information in SECY-99-129, "Effects of Electric Power Industry Deregulation on Electric Grid Reliability and Reactor Safety," May 11, 1999. On the basis of this study, the staff concluded that no further regulatory action was required, but did recommend certain staff follow-up actions.

CONTENTS

FIGURES

TABLES

APPENDICES

TABLES

ABBREVIATIONS

ASP	accident sequence precursor
CCDP	conditional core damage probability
CDF	core damage frequency
CFR	*Code of Federal Regulations*
EDG	emergency diesel generator
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FSAR	final safety analysis report
GDC	general design criterion
INEL	Idaho National Engineering and Environmental Laboratory (now INEEL)
ISO	independent system operator
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
LPCI	low-pressure coolant injection
MAIN	Mid-America Interconnected Network
MVAR	megavar
MW	megawatt
NAERO	North American Electric Reliability Organization
NERC	North American Electric Reliability Council
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
ORNL	Oak Ridge National Laboratory
PG&E	Pacific Gas and Electric Co.
PRA	probabilistic risk assessment
PWR	pressurized-water reactor
RCP	reactor coolant pump
RG	regulatory guide
SCE	Southern California Edison Co.
SBO	station blackout
SRM	staff requirements memorandum
VAR	volt amperes reactive
WSCC	Western Systems Coordinating Council

EXECUTIVE SUMMARY

This report presents recommendations addressing the potential effect of deregulation of the electric power industry on the nuclear plant offsite power system as requested in a staff requirements memorandum[1] dated May 27, 1997. This report also describes the offsite power system, discusses the principal criteria for evaluating the effects of deregulation on the nuclear plant offsite power system and the potential impact of deregulation on the nuclear plant offsite power system, and presents a review of the various staff risk-informed and engineering-based initiatives to evaluate deregulation issues related to the nuclear plant offsite power system. The report contains the following conclusions:

Evaluations performed by the staff indicate that the potential increase in risk resulting from grid-related loss of offsite power (LOOP) events due to deregulation is likely to be low; however, the staff will continue to monitor grid reliability and take action, as needed. For example, the North American Electric Reliability Council (NERC) reliability assessments and site visits indicate common grid reliability concerns. While the Nuclear Regulatory Commission does not have jurisdiction over operation of the grid, Information Notice 98-07, "Offsite Power Reliability Challenges From Industry Deregulation," February 27, 1998," alerted licensees to the potentially adverse effects of deregulation of the electric power industry on the reliability of the offsite power source. Consequently, nuclear power plants are expected to prepare for these concerns by ensuring that plant features for coping with LOOP and station blackout (SBO) events are properly monitored and maintained. In addition to the appropriate command, control, and communication infrastructure with the grid-controlling entity, existing regulatory controls should ensure the reliability of emergency power generators and the adequacy of protective relays and alarms for the switchyard and emergency buses.

As noted in SECY 99-129[2], the NRC will continue to promptly assess LOOP events as part of the inspection program and also as part of the accident sequence precursor (ASP) program. For events that exceed the ASP threshold of 1E-6, further review will be performed, where appropriate, to obtain plant-specific and potential generic insights concerning the event. If the inspection or ASP program reviews indicate that additional staff evaluation of the event is needed, the status of the plant response to deregulation concerns will be assessed using as a guide the protocol developed by Oak Ridge National Laboratory for the site visits. This information will indicate if more plant-specific or generic attention is necessary.

In addition, review of the NERC grid-reliability forecasts and follow-up discussions, as required, appear to be the most practical means of assessing the potential impact of deregulation on the offsite power system. Continued contact with NERC, the Federal Energy Regulatory Commission, and the Electric Power Research Institute will also enhance the NRC's understanding of potential deregulation issues related to grid reliability.

---

[1] U.S. Nuclear Regulatory Commission, Staff Requirements Memorandum, "Briefing on Electric Grid Reliability, April 23, 1997, and Briefing on Electric Utility Restructuring, April 24, 1997," May 27, 1997.

[2] SECY 99-129, "Effects of Electric Power Industry Deregulation on Electric Grid Reliability and Reactor Safety," May 11, 1999. Developed in cooperation with the Office of Nuclear Reactor Regulation.

On the basis of the staff's evaluation of the initiatives completed to date, the following recommendations were developed and subsequently noted in SECY 99-129.

(1) The staff will take no further regulatory action to address grid reliability associated with the deregulation issue.

(2) To ensure that the licensing basis is maintained, the staff will follow up on the NERC and site visit concerns, risk-informed analyses, operating experience, and ASP evaluations as follows:

   (a) The staff will evaluate the adequacy of (i) the existing technical guidance on offsite power and voltage issues, (ii) the degraded voltage protective relay setpoints, and (iii) the scope of the offsite power system frequency protection, including whether the existing reactor coolant pump underfrequency protection could lead to unnecessary trips. These actions will ensure that plant ac safety equipment remains protected from abnormal offsite system voltages and frequencies.

   (b) The staff will investigate causes of diesel generator unreliability identified from INEL-95/0035, "Emergency Diesel Generator Power System Reliability 1987–1993," February 1996. The staff will continue to assess the reliability of the onsite diesel generators to ensure that the reliability is maintained consistent with the risk studies used to develop the SBO rule (Title 10 *Code of Federal Regulations* [CFR] Part 50 Section 63).

   (c) The staff will continue to assess significant LOOP events that are reported in accordance with 10 CFR 50.72 and 50.73, for prompt review as part of the inspection program. The 10 CFR 50.73 LOOP events will also continue to be reviewed as part of the ASP program. Follow-up action will be considered, as indicated by the inspection program, for LOOP events that either meet or exceed the ASP conditional core damage probability of 1E-6, or that last longer than the national median time of approximately 30 minutes.

   (d) The staff will remain cognizant of the current status of grid issues, and will assess future electric power grid reliability and its potential impact on nuclear power plants' offsite power systems through its continued contacts with NERC, the Federal Energy Regulatory Commission and the Electric Power Research Institute.

1 INTRODUCTION

Deregulation of the electric power industry is part of the ongoing national trend to deregulate such major industries as the airlines, telecommunications, and natural gas. Before deregulation of the electric power industry, electricity was generated and transmitted by a single utility within predetermined geographic boundaries. In addition, consumer electricity rates were regulated. Further, a single utility had ownership of the generation and transmission systems that make up the grid in the utility's territory and sole responsibility for the design and coordination of generation and transmission facilities for reliable grid operation. Experience showed that under these conditions, the grid was a reliable source of electric power to the industry's nuclear power plants.

In 1992 the National Energy Policy Act was passed to encourage competition in the electric power industry. The National Energy Policy Act requires, among other things, open access to the electric transmission system without regard to geographic boundaries to promote competition among wholesale purchasers and sellers of electric power and statutory reforms to encourage utility participation in the formation of wholesale generators. The industry started to implement deregulation initiatives in 1996, following the Federal Energy Regulatory Commission (FERC) Order 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," April 24, 1996, which called for utilities to assure open and fair transmission access, system reliability, and reduced prices. Although the transmission system will remain regulated, State utility regulatory commissions have deregulated most of the generation system by removing the generating plants from the rate base and opening a power market. As utilities are deregulated they often restructure, creating generation subsidiaries or divesting their generation assets entirely.

Institutional, technical, and operating issues have emerged from the deregulation initiatives. The issues have been identified by FERC, the North American Electric Reliability Council (NERC), and individual licensees. Among institutional issues are those related to FERC requiring national conformance to grid-reliability standards. Among technical issues are those related to changes to the grid design and operating configuration that challenge operating limits and grid reliability. Among operating issues are those related to changes in the ownership, roles, responsibilities, and operational interfaces between the power market, the generating companies, and the transmission system owners. Following Commission briefings by the NRC staff and representatives from the Department of Energy, FERC, NERC, and the industry, the Commission identified four actions for the staff in a staff requirements memorandum (SRM), "Briefing on Electric Grid Reliability, April 23, 1997, and Briefing on Electric Utility Restructuring, April 24, 1997," May 27, 1997 (Ref. 1).

SECY-97-246, "Information on Staff Actions To Address Electric Grid Reliability Issues–WITS [work item tracking system] No. 9700205," October 23, 1997, presented a task action plan in response to the May 27, 1997, SRM. SECY-97-246 reported that three of the actions in the SRM had been completed (make contacts with other agencies; provide information regarding the V.C. Summer pressurized-water reactor (PWR) grid disturbance of July 11, 1989; and make regional contacts with power pool and reliability councils). The NRC also issued Information Notice 98-07, "Offsite Power Reliability Challenges From Industry Deregulation," February 27, 1998 (Ref. 2), to alert licensees to the potentially adverse effect of electric power industry

deregulation on the reliability of the offsite power source. The staff completed several activities as part of the task action plan, including a survey of 17 nuclear power plants and electric grid control centers, an assessment of the risk significance of potential grid unreliability due to deregulation, and an evaluation of loss of offsite power (LOOP) events at nuclear plants from 1980 through 1996. Contacts with NERC found that NERC completed reports in 1997 and 1998 assessing future electric power generation and transmission reliability on a regional basis.

This report presents background information for understanding the potential impact of deregulation of the electric power industry on the nuclear plant offsite power system and presents information compiled as part of the staff's task action plan to develop recommendations regarding the fourth item in the SRM:

> *The Commission asked the staff to give greater urgency to ensuring that related health and safety issues within the NRC's jurisdiction are addressed, particularly in reviewing the terms of the licensing basis and validating assumptions about grid reliability.*

2 BACKGROUND

2.1 Description of the Offsite Power System

The offsite power system is the preferred source of ac electric power for the industry's nuclear power plants. Nuclear power plants use this power to start and run redundant ac safety loads (emergency systems and engineered safety features) required to shut down the plant under all conditions.

Accident sequences at nuclear power plants have been initiated by grid disturbances that cause a LOOP to the ac electric safety loads needed to shut down the reactor. A LOOP is an event that occurs when all sources of offsite power are unavailable, causing the ac safety buses to de-energize, and onsite ac emergency power supplies to start and load. NUREG/CR 5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980–1996," June 1998 (Ref. 3), shows that there were 173 LOOPs between 1980 and 1996. Review of the accident sequence precursor (ASP) database found that 71 of the LOOPs met or exceeded the ASP threshold of 1E-6 conditional core damage (CCDP) probability. Plant-specific probabilistic risk assessment (PRA) studies have shown that station blackout (SBO) can be a significant contributor to core damage frequency (CDF). An SBO results from a LOOP and from the loss of all onsite ac emergency power. The range for the frequency of core damage as a result of an SBO accident is estimated in NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear power Plants," June 1988 (Ref. 4), as 1E-4 to 1E-6 per reactor-year. NUREG-1109, "Regulatory/Backfit Analysis for the Resolution of Unresolved Safety Issue A-44, Station Blackout," June, 1988 (Ref. 5), states as a goal that the expected CDF from an SBO could be maintained around 1E-5 or less per reactor-year for almost all plants.

By design, the offsite power system should be robust enough not to cause a LOOP or voltage or frequency instability following a trip of the nuclear unit or the largest single load or generator on the power system. In addition, the capacity and capability of the offsite power system are frequently demonstrated during a transfer of the station loads from the unit auxiliary transformer

to the offsite power supply following a unit trip. This is a severe test of the offsite power system since the unit trip significantly reduces the power being delivered to it and, within a few seconds, requires additional offsite power to run the station loads. The adequacy of the offsite power system to start and run the safety loads is demonstrated since the station load transferred generally exceeds the total accident safety load by a factor of 5 to 10.

Alternating current electrical equipment, such as ac induction motors (which are the majority of the loads in the industry's nuclear power plants), has specific ranges of voltage and frequency for satisfactory operation under running and transient conditions. Industry standards specify the ranges for such equipment. As an example, the National Electric Manufacturers Association [NEMA] standard "NEMA-MG1," which applies to ac induction motors in the U.S., specifies that motors should be operated within 10 percent of nominal voltage, 5 percent of nominal frequency, and 5 percent of combined nominal voltage and frequency. A loss in performance is experienced if the motor is operated beyond these tolerances because abnormal motor voltage or frequency directly affects motor starting and running torque, speed, current, and overload capacity. In addition, excessive abnormal voltages or frequencies may cause non-recoverable damage or may cause overload protective relaying to trip the motor circuit breaker.

Because abnormal offsite power system voltages or frequencies may degrade the performance of all onsite ac safety loads, the nuclear plant is designed and operationally prepared to withstand a degradation or LOOP. Upon degradation or LOOP, plant or grid protective features disconnect the offsite power system from the onsite ac safety buses and automatically connect the onsite ac emergency power supplies. In addition, unit protective trips may be initiated when offsite power voltage or frequency degrades to avoid exceeding reactor core thermal-hydraulic safety limits. The nuclear plants are also designed to cope with an SBO. Further, the plants operationally prepared for a degraded grid have plant procedures to cope with both LOOP and SBO events. In addition, the grid-controlling entities have operating procedures to drop loads to preserve the power system integrity and restore offsite power following a grid disturbance.

The paragraphs that follow (1) define the terms grid, offsite power system, transmission, grid reliability, adequacy, and security and (2) describe NERC and its plans to reorganize.

The terms "grid" and "offsite power system" can be used interchangeably. The offsite power system for each nuclear power plant consists of a generating system that includes all offsite sources of electric power, and a transmission system as described below. For regulatory purposes, the offsite power system boundary is generally described in the Final Safety Analysis Report (FSAR) to start at the terminals of the safety bus circuit breaker(s) that connect the offsite power supply to the safety bus(es) and includes the offsite transmission and generation systems. The nuclear plant switchyard, which is designed to maximize the availability of the transmission system to nuclear plants, is part of the transmission system. The plant switchyard is typically under the operational control of the licensee's system load dispatcher.

"Transmission" is an indefinite term, which usually designates the highest voltages used on the grid, usually 115 kV and higher. The transmission system transfers the energy from the generating units to the loads and distribution systems via multiple redundant paths. The transmission system also interconnects power generation and transmission systems of utilities to the grid to achieve economic benefits through transfer of power to each other's system.

Figure 1, “Major Interconnections and NERC Regional Councils,” shows the four distinct interconnections in the United States and Canada: the western Interconnection, eastern interconnection, eastern Canada interconnection, and Texas interconnection. The interconnections also provide for redundancy of generation and transmission capacity and capability to system loads such as a nuclear power plant. The interconnections also serve as a path to spread major system disturbances to several States. For example, a grid-initiated event in Idaho in 1996 affected up to eight nuclear plants in Washington, California, and Arizona, and tripped four of the eight nuclear power plants (licensee event report 275/96-012, Preliminary Notification of Occurrence-IV-96-042). Thus, the number of interconnections is both a strength and vulnerability.

“Grid reliability” is defined by NERC in terms of the “adequacy” of the generation system and the “security” of the transmission system. The adequacy of the generation system is measured by the reserve megawatt (MW) and megavar (MVAR) margins to provide for uninterrupted service (generation reliability). Reserve MWs are a basic requirement for maintaining the stability of the system frequency. The system frequency decreases when the generated MW is less than the load plus the reserve MW, and increases when generated MW is greater than the load MW. Reserve MVARs are a basic requirement for maintaining voltage stability. The voltage decreases when the generated MVAR is less than load plus the reserve MVAR, and increases when generated MVAR is greater than the load MVAR. Therefore, offsite power system generation and load MW and MVAR mismatches, for any reason, including those caused by deregulation initiatives, appear as frequency and voltage variations at the nuclear plant.

The “security” of the transmission system is defined in terms of the ability of the electric system to withstand sudden disturbances, such as short circuits and unanticipated loss of system elements (transmission reliability). Security is typically measured by the extent of time that power is unavailable to a class of customers. Loss of a transmission line causes increased power flows in the available transmission lines and lower voltages at the loads served by these lines, such as nuclear power plant equipment (e.g., safety system pump motors).

“Grid reliability” is presently controlled nationally through voluntary participation in the NERC. NERC is a consensus organization that has 10 regional councils and a large internal board of directors. Figure 1 shows the geographic areas that correspond to the 10 NERC regional councils. NERC is planning to reorganize as the North American Electric Reliability Organization. The North American Electric Reliability Organization is planned to be a self-regulating organization, with a smaller external board of directors, whose powers are defined by FERC. The North American Electric Reliability Organization is expected to require national conformance to a set of reliability standards.

FIGURE UNAVAILABLE ELECTRONICALLY

2.2 Principal Criteria for Evaluating the Effects of Deregulation on the Nuclear Plant Offsite Power System

From an engineering, licensing, and risk perspective, evaluation of the effects of deregulation of the nuclear plant offsite power system involves the criteria in Table 1, "10 CFR 50 Offsite Power System Principal Criteria and Common Measures." Table 1 shows the principal offsite power system design criteria and their common measures. The principal design criteria, including both deterministic and risk considerations, that provide the licensing basis for the offsite electric power system appear in 10 CFR 50, Appendix A, General Design Criterion (GDC) 17, "Electric Power Systems." GDC 17 establishes the following minimum requirements for the principal design criteria for the offsite electric power system: offsite power system capacity, capability, availability, and provisions to minimize the probability of a LOOP. In 10 CFR 50.63, "Loss of all alternating current power," the staff establishes that the SBO duration shall be based on the reliability of onsite emergency ac power sources, the expected frequency of a LOOP, and the probable time needed to restore offsite power. Licensees generally address conformance of the offsite power system to these requirements in their FSARs. GDC 17 and 10 CFR 50.63 establish other requirements, such as the number of offsite connections to the plant; these are not listed in Table 1 since they are fixed by the design.

Table 1 10 CFR 50 Offsite Power System Principal Criteria and Common Measures

Principal Criteria	**Measure**
Capacity	MVAR and MW generation and load mismatches that degrade offsite power system frequency and voltage
Capability	Voltage Frequency
Provisions to minimize LOOP probability	A unit trip should not degrade voltage to initiate a LOOP
Availability	Duration of a LOOP Expected frequency of a LOOP
SBO duration basis	Reliability of the onsite emergency ac power sources Expected frequency of a LOOP Probable time needed to restore offsite power

Evaluation of the principal criteria in Table 1 is consistent with Oak Ridge National Laboratory (ORNL)/NRC/LTR/98-12, "Evaluation of the Reliability of the Offsite Power Supply as a Contributor to Risk of Nuclear Power Plants," which recommends that offsite power [design] basis requirements be adequately addressed.

2.3 The Potential Impact of Deregulation on the Nuclear Plant Offsite Power System

The following documents indicate that deregulation has the potential to adversely impact grid reliability: NERC grid reliability forecasts in Appendix A, "North American Electric Reliability

Council Reliability Assessment for 1997–2006 and 1998–2007"; an NRC site survey in Appendix B, “Site Visits”; the actions by one licensee in Appendix C, “Actions of the California Independent System Operator To Assure Grid Reliability”; and a general stability assessment by the Electric Power Research Institute (EPRI) (Ref. 6). The information in these appendices was used to identify the following potential impacts of deregulation of the electric power industry on the offsite power system that could affect the principal criteria in Table 1:

(1) The grid design and operating configurations were established before the electric power industry was deregulated to ensure the correct voltages and frequencies on the system. Deregulation may result in unanalyzed grid operating configurations from (a) daily changes in the operable generators from implementing the power market and (b) power load flows changes from the consumer’s selection of a supplier, which identifies where the power flows. Once the circuit configuration is defined, Kirchhoff’s laws of electricity, not the power market or consumers, determine how the current divides among the different grid paths under each operating configuration. Failure to analyze the grid under changing conditions and reconfigure the grid to avoid adverse configurations could result in the following:

- Transmission line congestion, that is, individual transmission current flows that exceed previously established limits and cause abnormal voltages at the nuclear plant(s) while the plants are operating.

- Unexpected responses of the grid following faults on the generation or transmission system that cause abnormal voltages and frequencies at the nuclear plant(s).

(2) Defaults on generation bids may erode reserve capacity margins that are needed to maintain system frequency and voltage stability following a disturbance.

(3) Assumptions about the availability of the offsite power supplies could change. Licensees are selling their generating facilities that supply offsite power to the nuclear plants. In some cases, licensees are selling the black-start power supplies that are used to restore power to the grid following a grid blackout.

(4) The duration of a LOOP or an SBO may increase. Changes in ownership and control of generation and transmission facilities may increase recovery time because of less coordination between generation and transmission facilities following a grid disturbance.

(5) The NERC reliability forecasts and the Office of Nuclear Reactor Regulation (NRR)/ORNL site survey show that the effects of deregulation on the nuclear power plants are regional. A major grid disturbance could affect several nuclear plants simultaneously.

(6) Pressures to keep electricity rates competitive may result in a reduction of grid maintenance or a reluctance to invest in transmission system upgrades that are needed to preserve the present level of grid reliability to the nuclear plants.

(7) As nuclear units are sold to nonutility entities, the new owners may choose to operate differently to compete in the power market. For example, nuclear generators may need to load-follow, that is, run fully loaded during the week days and partially loaded at other times. This could potentially impact the licensee, reactor systems, and fuel performance.

2.4 Scope

The following items are discussed in Section 3 and provide the basis for the staff's recommendations regarding deregulation:

- The operating experience was assessed to identify and evaluate potential weaknesses regarding (1) previous protective schemes that could complicate power system availability and reliability and (2) the provisions to minimize the probability of a LOOP.

- NERC reliability forecasts were used to obtain insights on future generation system adequacy and transmission system security.

- Sensitivity studies were reviewed for potential changes to event frequency and duration related to SBO.

- The operating experience was used to verify that the reliability of the onsite emergency power system is as assumed in the analysis of the risk margins for LOOP and SBO events.

Potential concerns from weather-initiated and nongrid-initiated LOOP events, and the reliability of systems, such as high-pressure coolant injection, needed to cope with an SBO, were not included in the scope of the study.

3 EVALUATION OF THE PRINCIPAL CRITERIA

This section of the report uses the criteria and measures in Table 1 to evaluate the potential effects of deregulation of the electric power industry on the nuclear plant offsite power system. The principal criteria were grouped into the following three sections: (1) the adequacy of the offsite power system voltage and frequency at the nuclear plants was used to evaluate capacity and capability, (2) minimizing the probability of a LOOP following a unit trip, and (3) risk and reliability measures were used to evaluate availability and SBO duration basis. Each section ends with an evaluation and recommendation that is used to formulate a conclusion and recommendations at the end of the report.

3.1 Adequacy of the Offsite Power System Voltage and Frequency at the Nuclear Plants

NRC requirements address the adequacy of voltage measures and require degraded voltage protective devices to assure that the requirements GDC 17 in Appendix A to 10 CFR 50, are satisfied.

In a letter sent to all power reactor licensees, "Adequacy of Station Electric Distribution System Voltages," August 8, 1979 (Ref. 7), the NRC required analysis to confirm the adequacy of the voltage levels in the station's electric distribution system. In summary, the letter calls for plant-specific analysis, which shows that the offsite power system and the onsite distribution system are of sufficient capacity and capability to start and operate redundant ac safety loads within their required voltage ratings in the event of an anticipated transient (such as a unit trip) or an accident (such as a loss-of-coolant accident), whichever presents the greater load. Evaluation of the adequacy of the grid as a source of offsite power for a nuclear plant requires analysis of a circuit whose components are the nuclear plant electrical distribution system, the offsite and onsite generators, and the components of the transmission system. The analysis generally results in a worst-case minimum and maximum plant voltage, each based on the worst-case offsite power system capacity (MW and MVAR) and voltage conditions. The analysis also results in alarm and protective setpoints for required degraded voltage protective devices. The NRC reviewed the licensee responses to the August 8, 1979, letter. In addition, the NRC reviewed these analyses as part of an Electrical Distribution System Functional Inspection at some licensee facilities from 1989 to 1992.

Regardless of the outcome of deregulation of the electric power industry, nuclear plant protective features ensure protection of ac safety equipment from abnormal offsite power system voltage and frequency resulting from deregulation and all other conditions. Operation of degraded voltage relays initiates the following: (1) isolation of the offsite power system from the onsite ac electric safety-related auxiliaries, (2) the start of the onsite emergency ac power supplies, and (3) loading of the ac safety-related loads to the onsite supply. These relays operate as a result of a blackout or any other condition that degrades voltage, including conditions that may be caused by deregulation initiatives. A low-voltage alarm alerts operators to declining voltage conditions. However, numerous licensee event reports from 1993 to 1998, which are listed in Appendix D, "Operating Experience," Table D-1, "1993–1998 Events Identifying Weaknesses In Voltage-Related Analyses, Tests, and Surveillance Procedures Affecting Plant Design and Administrative Controls," indicate weaknesses that affected the adequacy of the degraded voltage design, particularly the degraded voltage protective setpoints, and in the administrative controls to cope with the LOOP. Such weaknesses may also indicate weaknesses in the technical guidance or that the licensees are periodically reviewing potential degraded voltage issues. Operating experience indicates that the existing technical guidance on offsite power system voltage issues, including the degraded voltage relay setpoints, needs to be addressed and was included in recommendation 2a (Ref. 8).

A degraded grid that affects the nuclear plant ac safety loads may also result from abnormal frequencies. At most nuclear plants, there is no frequency protection to isolate the nuclear plant's safety buses from abnormal offsite power supply frequency. However, plant and offsite power system protective relay operations are coordinated to ensure that the system frequency does not drop below acceptable levels, and to prevent widespread blackouts. These relays automatically trip unstable system generators and system loads, in a deliberate manner, until the system stabilizes. These relays operate as a result of insufficient capacity, blackout, or any other condition that leads to degraded frequency, including conditions caused by deregulation initiatives. However, the Western Systems Coordinating Council (WSCC) identified design deficiencies and recommended attention in the areas of the automatic controls and the protective relaying that ensure the adequacy of the system frequency (WSCC, 1994) (Ref. 9) and (WSCC, 1996) (Ref. 10). The WSCC investigation of major grid disturbances that occurred in 1994 and 1996 found that devices did not operate properly to sectionalize the grid

to maintain frequency stability, resulting in the cascaded trips of several nuclear and fossil units that exacerbated the disturbance. In addition, a site survey of 17 plants, which is summarized in Appendix B, recommended the following: “NRC staff should reevaluate the underfrequency protection trip settings and other grid considerations in view of concerns regarding cascading trips” (Ref. 8). This recommendation was included in SECY 99-129 (Ref. 8) under recommendation 2a. This includes the protection of the ac safety loads as, and whether, the existing reactor coolant pump underfrequency protection, which trips the unit when reactor limits are exceeded, is coordinated with the other frequency protection and leading to cascading trips during grid events. The recommendation was based on information from a utility suggesting that the independent system operator (ISO) protocol should require rigorous analysis of selected underfrequency scenarios.

A search of the operating experience also found that grid transients may initiate reactor protective trips before the event reaches the threshold of a degraded grid or LOOP. The search did not find any weaknesses in reactor protective features as a result of grid transients.

Evaluation and Recommendation

The nuclear power plants and the grid, in combination, must have adequate voltage and frequency protective relaying and alarms to ensure that changes in the design and operation of the offsite power system in a deregulated environment do not result in abnormal levels of voltage or frequency at redundant ac safety-related loads under any condition. In this regard, there are regulatory controls in place to ensure the adequacy of protective relays for emergency buses. However, the operating experience indicates weaknesses that affected the degraded voltage protective setpoints and scope of the frequency protection that need to be addressed.

To ensure that plant ac safety loads are protected from abnormal offsite system voltages and frequencies the staff will evaluate the adequacy of (1) the existing technical guidance on offsite power and voltage issues, (2) the degraded voltage relay setpoints, and (3) the scope of the offsite power system frequency protection to include whether the existing grid and reactor coolant pump underfrequency protection coordination could lead to unnecessary trips.

3.2 Minimizing the Probability of a Loss of Offsite Power Following a Unit Trip

In 10 CFR 50, Appendix A, GDC 17 requires in part that provisions shall be included to minimize the probability of losing electric power from any of the remaining offsite power supplies as a result of, or coincident with, the loss of power generated by the nuclear unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies. Even without the requirements in GDC 17, most utilities design and operate the offsite power system so that a unit trip (of any fossil, hydro, or nuclear unit) does not result in significantly degraded voltages or frequencies. To comply, the grid must have sufficient grid reserve capacity margin (MW and MVAR) to accommodate a nuclear plant trip that reduces the grid MW and MVAR capacity, and within a few seconds requires additional MW and MVAR to start and run the nuclear plant’s ac auxiliary and safety loads. Review of several FSARs indicates that licensees have generally stated therein that a unit trip will not result in a LOOP. However, review of the operating experience from 1988 through 1998 found five events listed in Appendix D, “Operating Experience,” Table D-2, “LOOPs That Followed a Unit Trip.” Table D-2 indicates five cases in which a unit trip caused a voltage drop or loss of voltage to the ac safety

loads at a nuclear plant. Note that the V.C. Summer unit trip listed in Table D-2 demonstrates how a unit trip resulted in cascading trips of other units, grid instability, and a LOOP.

Evaluation and Recommendation

Collectively, five unit trips over a 10-year period is not a significant number. However, individually, the trips may indicate specific offsite power system weaknesses that resulted in a LOOP at the nuclear plants.

A LOOP following a unit trip should be investigated by the staff as a degraded voltage issue.

3.3 Reliability and Risk

The assessment for future grid reliability and risks involves unquantifiable amounts of uncertainty as follows:

- The NRC and licensee reliability and risk assessments are based on historical operating data in a regulated industry and generally show that the nuclear plant offsite power supply is reliable. Grid operation in a deregulated industry may result in different operating data, particularly in view of changes in operation of the grid due to new roles and responsibilities, new entities that include the power exchange, and different operating reliability and engineering limits criteria that have the potential to invalidate the historical data.

- NERC grid reliability forecasts and an ORNL/NRC evaluation of the offsite power system as a contributor to risk at nuclear power plants used forecasted data developed by industry experts. The NERC reliability assessments have stated that assessing reliability beyond the near term is extremely difficult because of the level of uncertainty in the data since neither the generation resources nor loads are known in an open market.

It is important to understand (1) how the data for LOOP events are collected, and (2) that changes are being made to ensure that all LOOP events are reported to the NRC. LOOP events are generally reported to the NRC in accordance with 10 CFR 50.72 and 50.73 as a result of engineered safety features actuations that result in the start and loading of onsite emergency ac power supplies. However, there are seven plants at which the emergency power supplies are not considered engineered safety features. The staff issued the proposed rule revisions to capture these seven plants in accordance with 10 CFR 50.72 and 50.73 in June 1999, and plans to issue the final rule in February 2000.

It is also important to understand how the NRC data need to be used to capture all grid-initiated events. NRC studies generally classified LOOP events into severe-weather-related events, grid-related events, and plant-centered events. Severe-weather-related events are those in which the weather affected a large area and are capable of disrupting plant operation. Grid-related events are those in which widespread power system problems in the offsite power grid caused and impacted the duration of the LOOP. The data in NUREG/CR-5496 indicate six grid-related events. Plant-centered events are those in which the plant design and operational factors played a major role in the cause and duration of the LOOP. There are plant-centered grid-initiated events within the plant-centered grouping that had a local effect on the grid, such

as transmission system load dispatcher errors, transmission line faults near the plant, and switchyard events. The data in NUREG/CR-5496 show there were six plant-centered, grid-initiated events to include one load dispatcher error and five transmission line faults near the plant. In total there were 12 grid-initiated events and these were counted in the RES study that is discussed in Section 3.3.5. The 32 LOOP events initiated in the plant switchyard, which is located on the plant site but is part of the transmission system, were not counted for the purposes of risk studies. Understanding how the events are classified may be important when discussing grid failures with NERC, FERC, and the Department of Energy.

3.3.1 North American Electric Reliability Council Assessments of Future Grid Reliability

NERC presently considers the potential impact of deregulation and forecasts the generation and transmission system reliability on a regional basis. NERC has completed three reliability assessments: (1) “Reliability Assessment, 1997–2006,” October 1997, (2) “Reliability Assessment, 1998–2007,” September 1998, and (3) “1998 Summer Assessment,” May 1998. In Appendix A to this report, “North American Electric Reliability Council Reliability Assessment for 1997–2000 and 1998–2007,” the reports are summarized. Major observations from review of the reports follow::

- NERC reliability forecasts state that the system will be adequate for the next 3 to 5 years, but it faces significant challenges in transition to a fully competitive and open market.

- NERC reliability forecasts are highly area sensitive. NERC regional self-assessments present specific regional reliability concerns and plans or completed actions that address the concerns.

- NERC has identified opportunities for improvement, areas for increased attention, and the need to monitor performance.

NERC predictions about deregulation reducing capacity margins materialized in the summer of 1998 for some licensees.

- Detroit Edison, Philadelphia Electric Company, and Enron have filed complaints that as a result of new FERC procedures, some companies cut off power deliveries from their competitors by citing the risk of overloading their own transmission lines. The new procedures allow a utility to disconnect other utilities from its system if it finds that the reliability of the system is being endangered by the connection (Wall Street Journal, July 24, 1998).

- One power trader defaulted on its contract to supply electricity to several utilities, (Southern Company and First Energy Corporation, holding company for Duquesne, Centerior, and Ohio Edison power companies) following a sharp increase in power market prices (Wall Street Journal, July 9, 1998).

3.3.2 Evaluation of Loss of Offsite Power Events

The staff developed NUREG-1032 as part of its resolution of Unresolved Safety Issue A-44, “Station Blackout.” In NUREG-1032, the staff discusses actual LOOP events that took place

from 1968 through 1985. These were divided into three categories: plant-centered, weather-related, and grid-related. The staff found that frequency and duration of a LOOP are (and remain) important aspects to SBO accident sequences that can dominate the total risk at some nuclear power plants. These data are updated in NUREG/CR-5496.

Table 2, "NUREG-1032 and NUREG/CR-5496 – LOOP Frequency and Duration Comparison," shows that for grid-related LOOP events, the initiating frequency has a decreasing trend (an approximate order of magnitude reduction), and the duration has an increasing trend (an approximate increase by a factor of 4). NUREG/CR-5496 notes that the recovery times tend to be longer, but the data set is small.

Table 2 NUREG-1032 and NUREG/CR-5496 LOOP Frequency and Duration Comparison

Type of LOOP event	Frequency of occurrence per reactor-year		Median duration in minutes	
	1032	**CR-5496**	**1032**	**CR-5496**
Grid-related	0.018	0.0019	36	140
Plant-centered	0.087	0.04	18	20
Weather-related	0.009	0.0066	270	144
Total	0.114	0.0485	—	—

The data in NUREG-1032 and NUREG/CR-5496 also show that plant-centered events were the major cause of LOOP events, and that weather-related and grid-related events caused LOOPs to a much lesser degree. The data show that grid-related events are only a small percentage of the total LOOP frequency per site-year that is used as an input to PRAs that evaluate accident consequences from total LOOP. In addition, considering all the data in NUREG-1032 and NUREG/CR-5496, the median national average duration of LOOPs is approximately 30 minutes. The data in NUREG/CR-5496 reveal that if 10 additional grid-related events and plant-centered grid-initiated events were to occur, it would change the most recent total LOOP initiating frequency from 0.0485 to only 0.0586 per reactor-year. An order-of-magnitude increase in the grid-related and plant-centered grid-initiated LOOP initiating frequency would not result in a significant change in the total LOOP initiating frequency used in the PRA. Consequently the potential increases in risk due to deregulation is likely to be low.

The letter that issued NUREG/CR-5496 (Ref. 11), recommended that no further regulatory action is needed with respect to milestone 4 of the task action plan on grid reliability. The AEOD letter also stated that increases in grid-related LOOP frequency can be identified through routine monitoring and analysis of operating experience before they become a significant contributor to risk from LOOP events. In addition, the grid-related LOOP duration has an increasing trend that can also be identified through routine monitoring and analysis of operating experience before becoming a significant contributor to risk from LOOP events. Further, LOOP

events above the national median duration of 30 minutes may need review through the inspection process.

3.3.3 Accident Sequence Precursor Evaluation of Grid-Initiated Loss of Offsite Power Events

Offsite power system disturbances and LOOPs that initiate accident sequences are evaluated on an ongoing basis as part of the NRC ASP program. An ASP event has a CCDP of 1.0E-6 or more. Appendix E, “Accident Sequence Precursor Results for Grid-Related and Plant-Centered Grid-Initiated Events,” shows the ASP events from 1980 to 1996 that were also grid-initiated LOOP events. Table E-1, “Accident Sequence Precursor Results for Grid-Related Events From 1980 to 1996," lists the six grid-related events that occurred from 1980 to 1996. Table E-2, “Accident Sequence Precursor Results for Plant-Centered Grid-Initiated Events From 1980 to 1996,” shows nine plant-centered, grid initiated events that were ASP events. Table E-2 includes events in the switchyard that is part of the transmission system and that often has plant involvement through the operator interface. Three events in Table E-2 were counted twice since they affected two units. The tables also show the following:

- All grid-related events were ASP events.

- There has been, on average, one grid-initiated ASP LOOP event per year from 1980 through 1996 (six grid-related events from Table E-1 and nine plant-centered, grid-initiated ASP events from Table E-2).

3.3.4 Site Visits To Evaluate the Reliability of the Offsite Power Supply as a Contributor to Risk at Nuclear Power Plants

Members of the staff, with contractor support from ORNL, visited 17 nuclear power plants and their associated system control centers to obtain information regarding system operation during the transition to a deregulated environment. These visits included at least one plant in each of the 10 regional councils that are members of NERC. A standard set of questions was asked at each site visit. ORNL/NRC/LTR/98-12, “Evaluation of the Reliability of the Offsite Power Supply as a Contributor to Risk of Nuclear Power Plants” (Ref. 12) analyzes information obtained during the visits and documents a wide range of concerns from weaknesses in addressing the impact of deregulation. Appendix B, “Site Visits,” summarizes information contained in ORNL/NRC/LTR/98-12.

As part of the ORNL/NRC/LTR/98-12 report, a set of criteria was developed to gain a subjective method for quantifying the future impact of electric industry restructuring on LOOP frequency and time to restore offsite power. Expert opinion was used to apply the criteria to individual nuclear plants and to provide (1) a set of multipliers to be applied to the LOOP frequency developed from NUREG-1032 and NUREG/CR-5496, and (2) revised times to recover offsite power. This method is discussed in Section 5 of the ORNL report, and was applied to a group of 17 plants. Plants at which ORNL identified potential concerns with the transition to a deregulated environment were assigned a multiplier that increased their LOOP initiating frequency or regional blackout recovery time. Conversely, plants that had analyzed or were analyzing the transmission system to ensure adequate voltage were assigned multipliers that decreased their LOOP initiating frequency. Also, plants that had well-defined grid blackout procedures were assigned multipliers that decreased their regional recovery time.

The multipliers for the LOOP frequency ranged from 0.5 to 3.4, with an average of 1.0. The LOOP frequency for 4 of the 17 plants exceeded the average. The predicted time to restore offsite power ranged from 0.2 to 5.1 hours, with an average of 1.9 hours. Seven of the plants had recovery times that exceeded the average. Of the 17 plants, 3 were assigned multipliers that increased above the average both the LOOP initiating frequency and time to recover.

The following were noted from the review of the ORNL and NERC reports:

- Onsite follow-up found there is significant diversity among NERC regions and between utilities within regions in addressing the potential effects of deregulation that may impact the risk that are not evident from risk analyses. For example, predicted increases in the frequency and duration at some plants indicate that not all licensees will address deregulation without potentially eroding risk margins, and this is in conflict with a previous statement that the potential increases in risk due to deregulation is likely to be low.

- Appendix B contains a table from ORNL/NRC/LTR/98-12. The table shows NERC regional areas of concern. The ORNL report has identified grid-reliability concerns in some of the same areas as NERC reliability assessments. However, the NERC reliability assessments include regional self-assessments that generally provide completed or planned actions to address the concerns.

- The ORNL protocol that was used to conduct interviews at the sites and control centers, if updated to address the ORNL concerns, could be used as a guideline for NRC follow-up of future grid events as appropriate.

The following recommendations are made in ORNL/NRC/LTR/98-12 and explained in Appendix B. The staff's disposition of these recommendations is also discussed in Section 3.3.7 (p. 18).

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

- The impact of restructuring across the Nation in the next 5 years will most probably be significant; but currently, local area impacts are difficult to anticipate until ISO alignments and industry structure are fully established. The NRC should be vigilant to ensure 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.

The staff visited the California ISO in May 1998 and March 1999 as part of the staff action plan. The California ISO was of particular interest since California has fully deregulated, and consequently, is one of the areas that has addressed grid-reliability issues resulting from deregulation. The California ISO is a nonprofit agency that assumed operation of the California (and nearby) transmission systems from investor-owned utilities on March 31, 1998, as part of

deregulation of the electric power industry in California. Like the power pools in the U.S., the California ISO manages and controls regional operational and engineering activities related to maintaining grid reliability. Unlike other regional grid-reliability centers, the California ISO is mandated by a state law (AB 1890) that mentions reliability 26 times and gives the California ISO powers to address grid reliability.

The California ISO addressed the adequacy of the grid and nuclear plant ac power systems in terms of the factors that drive reliability, minimize power interruptions, and facilitate recovery as shown in Appendix C, "Actions of the California Independent System Operator To Assure Grid Reliability." At a meeting with NRC in March 1999, the California ISO stated that the greater command, control, and communication within the WSCC was a significant contributor to enhancing grid reliability. The following actions also significantly enhance command, control, and communication, and thus grid reliability:

- The NERC/WSCC grid reliability standards were revised for reliable operation of the grid as a result of events that had adverse effects on the adequacy and security of the western interconnection.

- Transmission control agreements were established between the generator and transmission system owners as binding contracts that specify technical and administrative terms and conditions to help ensure grid reliability.

- The California ISO performs the long-term, annual, daily, and hourly electrical security analysis to ensure that power system is operated in an analyzed configuration.

- The California ISO provides the generators and transmission system owners with daily and hourly watt, volt amperes reactive, and voltage requirements. The California ISO coordinates generator and transmission owner outages and redirects the scheduling to meet the requirements.

- Approximately $400 million was spent to conceptualize, plan, design, build, and implement the technical and operational processes and the monitoring, dispatch, and communication systems to ensure reliable operation of the grid.

- The California ISO has the authority to implement emergency procedures (i.e., for emergency market intervention) to redirect units on, loads off, and purchases/ sales/ resales. The California ISO reviewed the adequacy of the restoration and recovery procedures from a grid disturbance, particularly at licensees that have divested their offsite power supplies, or when the licensee no longer directly operates the transmission and generation systems.

3.3.5 Risk Significance of Potential Grid Unreliability Due to Deregulation

.
Appendix F, "Risk Significance of Potential Grid Unreliability Due to Deregulation," is a copy of the study that was completed by the Probabilistic Risk Analysis Branch, RES, to analyze the risk significance of grid unreliability as part of the task action plan. This sensitivity study was based on the postulated frequency of LOOPs and recovery times developed in ORNL/NRC/LTR/98-12 and on the data and models in NUREG/CR-5496 to include both grid-

related events and plant-centered, grid-initiated events. The analysis estimated the increase in CDF caused by deregulation of the average plant (i.e., if all plants had the same risk) and for outlier plants (i.e., plants that might be most affected by deregulation). For the outlier plants, the maximum increase in CDF was based on the maximum increase in LOOP frequency and the worst case identified in ORNL/NRC/LTR/98-12. The RES study concluded that the risk significance of potential grid unreliability due to deregulation is likely to be minimal for the average nuclear power plant, although a sensitivity study showed that the largest increase in CDF caused by deregulation is 1.5E-5 per reactor-year.

As part of the task action plan, NRR performed a study to assess the potential effect of deregulation on nuclear power plant CDF (Ref. 13). This study modeled an example PWR and boiling-water reactor with baseline SBO CDF of 3.6E-6/reactor-year and 5.3E-6/reactor-year, respectively. The study assumed the values of grid-related LOOP frequency and non-recovery times reported in NUREG-1032, and used the staff's simplified probabilistic assessment risk models (which are used for the ASP program). Sensitivity studies were performed to determine the combination of factors (LOOP frequency, recovery time) needed to increase the baseline CDFs to the SBO goal of 1E-5/reactor-year. For the example PWR, the grid-related LOOP frequency must increase by more than a factor of 10 (from 0.01/reactor-year to more than 0.1/reactor-year) and the expected offsite recovery time must double before the SBO goal is compromised. For boiling-water reactors, the grid-related LOOP frequency must increase by about six times (from 0.01/reactor-year to 0.06/reactor-year) and the expected offsite recovery time must double before the SBO goal is compromised. Other combinations of LOOP frequency and recovery time to meet the SBO goal are given in the NRR report.

3.3.6 Onsite Alternating Current Emergency Power System Reliability

In consideration of the potential impact of deregulation on a nuclear plant SBO, it is equally important to review the functional reliability of the emergency power system used to mitigate the LOOP and prevent a LOOP event from progressing to an SBO event. The Idaho National Engineering Laboratory (INEL) (now INEEL), under NRC contract, completed a reliability study, INEL-95/0035, "Emergency Diesel Generator Power System Reliability, 1987–1993," February 1996 (Ref. 14). INEL-95/0035 indicated that the reliability estimate for 29 plants reporting under Regulatory Guide (RG) 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric power Systems at Nuclear Power Plants" (Ref. 15), with a 0.950 target goal is 0.987. The target reliability estimate for the emergency diesel generators (EDGs) at RG 1.108 plants with a 0.975 target goal is 0.985. This study notes that the target reliability goals do not require or account for unavailability of the EDG due to maintenance out of service. This study shows maintenance out of service could contribute to EDG reliability.

A letter issuing the report noted that "The overall nature of the failures experienced by the plants reporting per RG 1.108 during actual demands differed somewhat from those discovered during monthly surveillance testing, engineering and design reviews, and routine inspections. This indicates that the current testing and inspection activities may not be focusing on the dominant contributors to unreliability during actual demands and may need to be modified to better factor in the conditions and experiences gained from actual system demands." INEL plans to complete an update of the INEL-95/0035 study by January 2000.

3.3.7 Summary Evaluation and Recommendations for Sections 3.3.1 through 3.3.6

Risk evaluations performed by the staff indicate that there is margin to accommodate the potential increase in risk due to deregulation or that the potential increase in the risk resulting from deregulation is likely to be low. In addition, the risk margins do not provide justification for either licensee actions or vigilant NRC action as recommended in ORNL/NRC/LTR/98-12. As stated in the introduction to this report, IN 98-07 was issued to alert licensees to the potential effects of deregulation on the reliability of the offsite power source. Consequently, the staff should take no further regulatory action.

The need for monitoring and follow-up on selected events by the staff is supported by (1) NERC and ORNL reports that indicate that the impact of deregulation may result in regional grid-reliability concerns, (2) some cases in both the NERC and the ORNL/NRC reports that indicate common regional grid reliability concerns, (3) the RES analysis that indicates that individual plants may possibly exceed the SBO objective of 1E-5 per reactor-year, (4) an increasing trend in the grid-related recovery time from 36 minutes to 140 minutes, (5) all grid-related LOOP events meeting or exceeding the ASP threshold of 1E-6 CCDP, and (6) staff observations in INEL-95/0035 about EDG reliability. The staff should

- Monitor LOOP events to detect (and ensure correction of) increases in grid-related LOOP frequency or duration before they become a significant contributor to risk from LOOP events. All grid-related events; plant-centered, grid-initiated events; and events of national interest that affected a nuclear plant and are reported in accordance with 10 CFR Part 50.72 or 10 CFR 50.73 should be considered for evaluation as follows: For events that meet or exceed the ASP CCDP of 1E-6 or have a duration in excess of 30 minutes, onsite and grid control center follow-up, such as an augmented team inspection, should be considered, using the protocol in ORNL/NRC/LTR/98-12, Appendix C, updated to specifically address ORNL concerns, as a guideline.

- Take a forward look at grid reliability by reviewing NERC reliability assessments. NERC grid-reliability concerns should be reviewed by the staff and discussed with NERC as appropriate. In addition, communication with NERC, EPRI, and FERC at the program level, should enhance the forward-looking view of deregulation, including ongoing programs and potential weaknesses.

- The known causes of diesel generator unreliability identified in INEL-95/0035 should be investigated. In addition, the staff should ensure that the reliability of the onsite diesel generators, to include maintenance out of service, is maintained commensurate with the risk studies used to develop the SBO rule.

4 CONCLUSION

Evaluations performed by the staff indicate that the potential increase in risk resulting from grid-related LOOP events due to deregulation is likely to be low; however, the staff will continue to monitor grid reliability and take action, as needed. For example, the NERC reliability assessments and site visits indicate common grid reliability concerns. While the NRC does not have jurisdiction over operation of the grid, Information Notice 98-07, “Offsite Power Reliability

Challenges From Industry Deregulation," February 27, 1998," alerted licensees to the potentially adverse effects of deregulation of the electric power industry on the reliability of the offsite power source. Consequently, nuclear power plants are expected to prepare for these concerns by ensuring that plant features for coping with LOOP and SBO events are properly monitored and maintained. In addition to the appropriate command, control, and communication infrastructure with the grid-controlling entity, existing regulatory controls should ensure the reliability of emergency power generators and the adequacy of protective relays and alarms for the switchyard and emergency buses.

The NRC will continue to promptly assess LOOP events as part of the inspection program and also as part of the ASP program. For events that exceed the ASP threshold of 1E-6, further review will be performed, where appropriate, to obtain plant-specific and potential generic insights concerning the event. If the inspection or ASP program reviews indicate that additional staff evaluation of the event is needed, the status of the plant response to deregulation concerns will be assessed using as a guide the protocol developed by ORNL for the site visits. This information will indicate if more plant-specific or generic attention is necessary.

In addition, review of the NERC grid-reliability forecasts and follow-up discussions, as required, appear to be the most practical means of assessing the potential impact of deregulation on the offsite power system. Continued contact with NERC, FERC, and EPRI will also enhance the NRC's understanding of potential deregulation issues related to grid reliability.

5 RECOMMENDATIONS

On the basis of the staff's evaluation of the initiatives completed to date, the following recommendations were developed and subsequently noted in SECY 99-129 (Ref. 8).

(1) The staff will take no further regulatory action to address grid reliability associated with the deregulation issue.

(2) To ensure that the licensing basis is maintained, the staff will follow up on the NERC and site visit concerns, risk-informed analyses, operating experience, and ASP evaluations as follows:

   (a) The staff will evaluate the adequacy of (i) the existing technical guidance on offsite power and voltage issues, (ii) the degraded voltage protective relay setpoints, and (iii) the scope of the offsite power system frequency protection, including whether the existing reactor coolant pump underfrequency protection could lead to unnecessary trips. These actions will ensure that plant ac safety equipment remains protected from abnormal offsite system voltages and frequencies.

   (b) The staff will investigate causes of diesel generator unreliability identified from INEL-95/0035, "Emergency Diesel Generator Power System Reliability 1987–1993," February 1996. The staff will continue to assess the reliability of the onsite diesel generators to ensure that the reliability is maintained consistent with the risk studies used to develop the SBO rule (10 CFR 50.63).

(c) The staff will continue to assess significant LOOP events that are reported in accordance with 10 CFR 50.72 and 50.73, for prompt review as part of the inspection program. The 10 CFR 50.73 LOOP events will also continue to be reviewed as part of the ASP program. Follow-up action will be considered, as indicated by the inspection program, for LOOP events that either meet or exceed the ASP conditional core damage probability of 1E-6, or that last longer than the national median time of approximately 30 minutes.

(d) The staff will remain cognizant of the current status of grid issues, and will assess future electric power grid reliability and its potential impact on nuclear power plants' offsite power systems through its continued contacts with NERC, the Federal Energy Regulatory Commission and the Electric Power Research Institute.

6 REFERENCES

1. U.S. Nuclear Regulatory Commission, Staff Requirements Memorandum, "Briefing on Electric Grid Reliability, April 23, 1997, and Briefing on Electric Utility Restructuring, April 24, 1997," May 27, 1997.

2. U.S. Nuclear Regulatory Commission, Information Notice 98-07, "Offsite Power Reliability Challenges From Industry Deregulation," February 27, 1998.

3. U.S. Nuclear Regulatory Commission, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980–1996," NUREG/CR-5496, June 1998.

4. U.S. Nuclear Regulatory Commission, "Evaluation of Station Blackout Accidents at Nuclear Power Plants," NUREG-1032, June 1988.

5. U.S. Nuclear Regulatory Commission, "Regulatory/Backfit Analysis for the Resolution of Unresolved Safety Issue A-44, 'Station Blackout'," NUREG-1109, June 1988.

6. Electric Power Research Institute, "Breakthrough in Stability Assessment," *EPRI Journal*, August 1996.

7. U.S. Nuclear Regulatory Commission, letter to All Power Reactor Licensees, "Adequacy of Station Electric Distribution System Voltages," August 8, 1979.

8. U.S. Nuclear Regulatory Commission, SECY 99-129, "Effects of Electric Power Industry Deregulation on Electric Grid Reliability and Reactor Safety," May 11, 1999.

9. Western System Coordinating Council, "WSCC System Disturbance Report," December 14, 1994.

10. Western System Coordinating Council, "WSCC Preliminary System Disturbance Report," December 8, 1996.

11. U.S. Nuclear Regulatory Commission, Office for Analysis and Evaluation of Operational Data, letter from C.E. Rossi, “Issue of Special Report–Emergency Diesel Generator Power System Reliability 1987–1993, INEL-95-0035,” March 22, 1996.

12. U.S. Nuclear Regulatory Commission, “Evaluation of the Reliability of the Offsite Power Supply as a Contributor to Risk of Nuclear Plants,” ORNL/NRC/LTR/98-12, August 1998.

13. Nicholas T. Saltos and Daniel M. O’Neal, “Risk Impact of Electric Grid ‘Deregulation’ on Nuclear Power Plants,” September 2, 1998.

14. U.S. Nuclear Regulatory Commission, “Emergency Diesel Generator Power System Reliability 1987–1993,” INEL-95/0035, February 1996.

15. U.S. Nuclear Regulatory Commission, “Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants,” Regulatory Guide 1.108.

APPENDICES

APPENDIX A

North American Electric Reliability Council
Reliability Assessment for 1997–2006 and 1998–2007

North American Electric Reliability Council
Reliability Assessment for 1997–2006 and 1998–2007

As part of the task action plan, the Nuclear Regulatory Commission has maintained communication with the North American Electric Reliability Council (NERC) and reviewed several NERC documents to stay informed about deregulation issues.

NERC was formed in 1968 as one of the corrective actions from northeast grid blackouts that occurred in the 1960s. NERC's role is to coordinate, promote, and communicate information about the reliability of the electric utility generation and transmission systems. NERC membership and member compliance with its reliability criteria are voluntary. NERC is presently a consensus organization made up of 10 independent councils and an internal board of directors of approximately 35 directors. NERC's plans to expand its charter and reorganize as the North American Electric Reliability Organization (NAERO) are viewed as significant. NAERO is planned to be a self-regulating organization with a smaller external board of directors whose powers are defined by the Federal Energy Regulatory Commission (FERC). NAERO is expected to require national conformance to a set of standards and to have the authority to impose fines as appropriate.

NERC forecasts generation and transmission reliability. NERC has completed a "Reliability Assessment, 1997–2006," October 1997; a "Reliability Assessment, 1998–2007," September 1998; and a "1998 Summer Assessment," May 1998. The reports assess future electric generation and transmission reliability on a regional basis and identify regional grid reliability concerns, opportunities for improvement, areas for increased attention, and the need to monitor performance. The following statements were either obtained or developed from the NERC reports.

- The system will be adequate for the next 3 to 5 years, but it faces significant challenges in transition to a fully competitive and open market. The challenges are related to maintaining adequate capacity and capability, and minimizing the probability of a grid disturbance.

- The potential exists for capacity shortfalls and the erosion of capacity margins. To NERC, the risk is that an inadequate supply of either resources or transmission could result in an inability to supply electricity to the customer. NERC forecasts that electric supply adequacy could deteriorate in the long term if development of additional generating and transmission capacity does not keep pace with growing customer demand. NERC states that about 24,400 megawatt (MW) of generation additions are planned (not committed to or under construction) before 2002, and demand is projected to grow by about 36,000 MW. NERC also states that only 6,588 miles of new transmission (230 kV and above) are planned throughout North America over the next 10 years. This is less than the transmission miles that have been added over the last 5 years.

- Capacity margins under certain conditions may decrease to dangerously low levels. Margins in Electric Reliability Council of Texas (ERCOT) could fall below 10 percent unless proposed capacity additions are constructed by 2003, in the eastern interconnection by 2004, and in the western interconnection by 2007.

- NERC also states that assessing reliability beyond the near term is extremely difficult because of the level of uncertainty in the data since neither the generation resources nor loads are known in an open market.

- Market-driven changes in transmission usage patterns, the number and complexity of transactions, and the need to deliver replacement power to capacity-deficient areas are causing new transmission limitations to appear in new and unexpected locations.

- Increasing reliance on capacity purchases from undisclosed sources and the reluctance of generation developers to disclose plans for future capacity additions make modeling of the system for long-term transmission analysis virtually impossible.

- Transition to the year 2000 will be a critical challenge to the electric industry. At the request of the Department of Energy, NERC is coordinating the electric industry's response to this challenge.

- Improvement opportunities exist, particularly in system protection. A recent post-disturbance analysis by NERC shows opportunities for improvement: system protection, communications, planning and operational analyses, training, and rights-of-way maintenance. System frequency protection was noted as an area in which increased attention needs to be focused, since many recent disturbances were triggered or aggravated by misoperation of protective systems that are designed to prevent physical damage and cascading trips.

- The integrated planning process, which ensured coordination of generation and transmission plans in the past, is being dismantled as the industry restructures for an open market. These processes are being replaced with processes that are neither mature nor fully developed.

- The evolution of retail access is also injecting uncertainty into the reliability picture. The information and control to fully implement the concept of direct retail access are not yet available to deal with sales volume. Legislative and regulatory initiatives will occur at a pace that could overtake the industry's ability to manage them.

- It is clear that evolution of the industry deregulation introduces uncertainties that could adversely impact the future of reliability of the bulk power systems of the US and Canada. Performance will have to be continually monitored as the electric industry proceeds.

- As part of the reliability assessments, the NERC regional councils perform self-assessments. In some cases the self-assessments indicate potential weaknesses in the supply adequacy and security. Nuclear plant outages in both the U.S. and Canada, and peak demands in excess of capacity were cited as the main causes of generation system unreliability. Transmission line overload (congestion) was cited as a challenging transmission system security. In all cases, the self-initiated actions to correct weaknesses were noted, particularly procedure and operator training activities to enhance operational preparedness.

NERC "1998 Summer Assessment" contributed the following insights:

- Ongoing nuclear generation outages in the Mid-America Interconnected Network (MAIN) Region, New England, Michigan, and Ontario continue to reduce electricity supplies in several areas. Having adequate resources to meet customer demands for electricity in these areas will depend on the ability of the transmission system to deliver replacement supplies. The ability of the transmission system in the Midwest to provide simultaneous delivery of replacement power to the MAIN Region and Michigan is untested.

- Last summer, a number of key transmission system interfaces were frequently operated up to their limits to meet the import requirements of resources-deficient areas, especially in and adjacent to the MAIN Region. That trend is expected to continue this summer.

- Throughout the regions, parallel path flows from increased electricity transfers are stressing transmission systems. These flows are at magnitudes and in directions not anticipated at the time the systems were designed. Consequently, system operators are relying more on special operating procedures and special protection systems to ensure system security.

- A significant amount of demand is under contract and can be interrupted during system emergencies to keep supply and demand in balance.

- Coordinated operation of the transmission system will be essential to the reliability of the eastern interconnection this summer. The transmission system will be required to operate under unprecedented and sometimes unstudied conditions. Day-to-day and hour-to hour coordination between and among control area operators and security coordinators will be necessary to operate under the challenging conditions expected this summer.

- Despite the efforts of the MAIN Region to improve the resource situation, MAIN will have to implement transmission loading relief procedures to manage the loadings on the various elements of the transmission systems.

- The stated assumptions in the NERC forecast are as follows:

  - The weather will be normal.
  - Economic activity will occur as assumed in the demand forecasts.
  - Generating and transmission equipment will perform at average availability levels.
  - Generating units that are undergoing planned outages will return to service as scheduled.
  - Generating unit and transmission additions and upgrades will be in service as scheduled.
  - Demand reductions expected from direct control load management and interruptible demand contracts would be effective, if and when they are needed.
  - Electricity transfers will occur as projected.

APPENDIX B

Site Visits

Site Visits

As part of the task action plan, members of the staff, with contractor support from Oak Ridge National Laboratory (ORNL), visited 17 nuclear power plants and system control centers to obtain information regrading system operation during the transition to a deregulated environment. These trips included all of the 10 regional councils that are members of the North American Electric Reliability Council (NERC). Preceding to the trips, a protocol was developed to request information regarding electric power grid performance, impact on nuclear plant operations, forecasting, emergency conditions, and recovery from offsite power disturbances. Industry participation was on a voluntary basis and provided the staff with significant insights regarding the interrelationship between the nuclear plants and the system control centers. An evaluation of the information gathered during the visits was summarized in ORNL report, "Evaluation of the Reliability of the Offsite Power Supply as a Contributor to Risk of Nuclear Power Plants," ORNL/NRC/LTR/98-12, August 1998 (Ref. 11).

As part of the ORNL/NRC/LTR/98-12 report, a set of criteria was developed to provide a subjective method for assessing the future impact of electric industry restructuring on loss of offsite power (LOOP) frequency and time to restore offsite power. Experts who were consulted to apply the criteria to individual nuclear plants provided a set of multipliers to be applied to the LOOP frequency given in NUREG-1032, and revised times to recover offsite power. This method is discussed in Section 5 of the ORNL report, and was applied to a group of 17 plants. Plants that appeared to have potential weaknesses associated with deregulation were assigned a multiplier that increased their LOOP initiating frequency or regional blackout recovery time. Conversely, plants that had analyzed or were analyzing the transmission system to ensure adequate voltage were assigned multipliers that decreased their LOOP initiating frequency. Plants that had well-defined and contracted grid blackout procedures were assigned multipliers that decreased their regional recovery time. Information gathered from visits to 17 plant sites documented a wide range of concerns from weaknesses in addressing the impact of deregulation that could change the LOOP initiating frequency and duration.

The multipliers for the LOOP frequency ranged from 0.5 to 3.4, with an average of 1.0. The LOOP initiating frequency for four plants was greater than the average. The predicted time to restore offsite power ranged from 0.2 to 5.1 hours, with an average of 1.9 hours (most plants have the capability to provide core cooling for 4 hours without ac power). Seven plants had recovery times that were greater than the average but this is not meaningful without knowledge of actual coping time. Of the 17 plants, 3 had multipliers that were both greater than the LOOP initiating frequency and regional recovery time average. Table 6.1 from ORNL/NRC/LTR/98-12 shows NERC regional areas of concern. NERC reliability assessments identified grid reliability concerns in some of the same areas and that they were being addressed or planned to be addressed by the NERC regional councils.

The following information was obtained from ORNL/NRC/LTR/98-12:

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.

Overview of Concerns

Restructuring of the electric power industry is resulting in an 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 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.

Summary

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 Western Systems Coordinating Council [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 5 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.

Restructuring's impact on each of the reliability councils varies significantly. Table 6.1 of the ORNL report presents a regional summary of the findings of ORNL 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 toward full industry restructuring, as shown by the third and fourth lines on the table. Four regions employ widespread use of advanced tools (ERCOT, Florida Reliability Coordinating Council [FRCC], Mid-Atlantic Area Council [MAAC], WSCC and three (East Central Area Reliability Coordination Agreement [ECAR], Mid-Continent Area Power Pool [MAPP], Southwest Power Pool [SPP]) were not as advanced. In one region (MAIN) the use of advanced tools varies from control area to control area. In two other regions (Northeast Power Coordinating Council [NPCC] and Southeastern Electric Reliability Council [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.

The ORNL report further states:

> 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	*X*	√	√	√	S	*X*	S	S	*X*	√
Commercial restructuring	*X*			√	*X*	*X*	S	*X*	*X*	S

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

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

APPENDIX C

Actions of the California Independent System Operator
To Assure Grid Reliability

Actions of the California Independent System Operator To Assure Grid Reliability

As part of the task action plan, members of the staff, with contractor support from ORNL, visited 17 nuclear power plants and system control centers to obtain information regarding system operation during the transition to a deregulated environment. The staff also visited the California independent system operator (ISO) in May 1998 and March 1999. The California ISO visits provided valuable insights since California had, with a few exceptions, fully deregulated its electric power industry.

The California ISO is a nonprofit agency that assumed operation of the California (and nearby) transmission systems from investor-owned utilities on March 31, 1998, as part of deregulation of the electric power industry in California. Nuclear plant licensees Southern California Edison Co. (SCE), San Diego Gas and Electric, and Pacific Gas and Electric Co. (PG&E) participate in the California ISO. Like the power pools in the U.S., the California ISO manages and controls regional operational and engineering activities related to maintaining grid reliability. Unlike other regional grid reliability centers, the ISO is mandated by a State law (AB 1890) that mentions reliability 26 times. State law AB 1890 gives the ISO authority to mandate the following:

- transmission line(s) be built
- generator(s) be built
- authorize spot power contracts
- under emergency conditions, run out of the market

Implementation of deregulation initiatives in California has also resulted in a power market that auctions the electricity produced by the generators, and an ISO that operates the grid. The power market obtains the load requirements from the ISO and solicits bids, typically for a capacity, ramp rate, and cost per MW-hour in each of the power markets (base load power, supplement power on demand, grid black-start capacity and capability, etc). Anyone can bid on the power market by obtaining the approval of FERC. The power market results define the generators that will run to the grid. The results of the power market are forwarded to the ISO who has assumed responsibility for grid reliability, engineering, and operating limits; and directs operation of generating and transmission companies directly or through the traditional load dispatchers.

The ISO operates the electric transmission grid in a reliable manner and gives open access to all qualified users. In California, the ISO employs approximately 400 people. The California ISO spent approximately $400 million over 4 years. To ensure that the system is operated reliably, the ISO continuously analyzes, monitors, and directs operation of the grid to assure continuous operation within the ratings of the equipment and loads in the circuit. The ISO also implements and enforces minimum reliability criteria, schedules the transmission, coordinates outages, performs reliability analysis to assure the system will work within specific reliability criteria, directs the operating parameters of the generators, and directs restoration and recovery following a grid disturbance. The ISO completes daily power system analyses after the power exchange bids before the power market closes and again after the market closes to assure the grid will be operated in an analyzed condition. Typical analyses are load flow, voltage profiles, short-circuit analyses, and stability analysis to ensure grid reliability. The ISO requires rebidding, or redirects the bids, when the analyses do not provide for a reliable system.

The ISO addressed the adequacy of the grid and nuclear plant ac power systems in terms of the factors that drive reliability, minimize power interruptions, and facilitate recovery as follows:

Command, control, and communication. At the meeting between the NRC and the California ISO in March 1999, the California ISO stated that there was greater command, control, and communication within the WSCC. The California ISO believes this has contributed to grid reliability as (1) three independent major regions PG&E, SCE, and San Diego Gas and Electric are being operated as one region maximizing the availability of the transmission and generation resources and (2) the need for operator intervention has been significantly reduced. The ISO operates and maintains the primary and backup real-time communications network.

WSCC operating and reliability criteria. The NERC/WSCC grid-reliability standards were revised for reliable operation of the grid as a result of events that had unfavorable effects on the adequacy and security of the western interconnection. The criteria were revised to add that the grid must remain stable following the sudden loss of all generating plants feeding a common switchyard. In the past, nuclear power plant licensees generally analyzed the loss of one unit.

Transmission control agreements. These agreements were established between the generator and transmission system owners as binding contracts that specify technical and administrative terms and conditions to help ensure grid reliability. The contracts are presently being revised to impose penalties and sanctions for violating ISO requirements. The contracts caused the nuclear plant licensees and the California ISO to identify and address nuclear plant electrical vulnerabilities that could emerge from deregulation.

As a load on the grid, the licensees contracted with the ISO for its offsite power and grid black-start capability. To develop technical requirements for the contract, the staff at San Onofre and Diablo Canyon reevaluated loss of ac power conditions requiring operation of safety-related power systems, degraded voltage setpoints, the adequacy of actuation signals for operation of the safety-related power system following a loss of power, and the sequence for starting and loading the safety-related power supply. As a result of the West Coast grid disturbance in 1996, both licensees reviewed the effect of the offsite power system voltage drop following the trip of two operating units at their respective sites to ensure the ac safety-related loads connection was delayed until the voltage recovered to an acceptable level.

To ensure it could meet the contract requirements of San Onofre and Diablo Canyon, the ISO determined the grid operating configurations and conditions that would degrade the nuclear plant power requirements and established protocols to take corrective actions to prevent degradation. As a result, the grid conditions leading to a degraded nuclear plant safety-related bus voltage were identified and alarmed, and corrective actions were proceduralized by the ISO. The ISO contracted black-start capability with three other plants to ensure timely restoration of power to the grid and nuclear plants. The ISO has established nuclear plant power availability and requirements as a priority. In the end, the ISO operating protocol and procedures ensured the adequacy of nuclear plant offsite power and the restoration of offsite power following collapse of the grid.

As a generator, the owners of San On0fre and Diablo Canyon nuclear plants contracted with the ISO as regulatory “must run” units. That is, the State had mandated that these plants run when available on a cost-based rate and not on a market-driven rate. When the units’

investment costs are recovered, cost basis may be converted to a market-based rate. PG&E and SCE observed that after they recover their investment costs they may be required to give up their regulatory must run status and compete in the market. This may require that they load follow. This would need to be evaluated and limits established.

Sanctions. The ISO is in the process of implementing severe financial penalties for not meeting such contract obligations as delivering power as scheduled, complying with operating instructions, or adhering to reliability criteria.

Security analysis. The grid is an electrical circuit through which power flows according to the laws of electricity. Before implementing power market results, the California ISO performs security analyses (load flow, voltage, short circuit, and stability analysis) to assure the system is always operated in an analyzed condition.

The ISO does the long-term, annual, daily, and hourly electrical analysis to ensure that offsite power system voltage and frequency are stable, node and terminal voltages are adequate, load and short circuit current flows are within equipment ratings, and the minimum operating reliability criteria are met. To date these studies have identified congestion (overloads), abnormal conditions, and remedial actions that include redirecting the power market.

Transmission and generation scheduling. The ISO provides the generators and transmission system owners with daily and hourly schedules that are the wattage, volt ampers reactive (VAR), and voltage requirements as a function of time. The ISO coordinates generator and transmission owner outages and redirects the scheduling as required.

Significant resource commitment to control grid. Approximately $400 million was spent to conceptualize, plan, design, build, and implement the technical and operational processes and the monitoring, dispatch, and communication systems to ensure reliable operation of the grid. The California ISO has a full-time staff of approximately 400 employees, indicating the magnitude of the task to control the grid. One of the two California ISO operating centers has 130 operators, 30 schedule coordinators, 13 operation engineers, and 7 planners.

Reliability and economic decisions in the daily operation of the grid system not made by the same parties. Conflicts between grid reliability and cost of electricity were eliminated in the restructuring. The ISO is responsible for reliability. The power market determines the economic alternatives and the price of electricity. The ISO has the authority to intervene in the power market to request alternate power market bids to resolve anticipated operating problems or, on an emergency basis, to redirect real time operations.

Restoration and recovery. The ISO has the authority to implement emergency procedures for emergency market intervention to redirect units on, loads off, and purchases/sales/resales. The California ISO reviewed the adequacy of the restoration and procedures to recover from grid disturbances, particularly at licensee facilities that have divested their offsite power supplies, or when the licensee no longer directly operates the transmission and generation systems.

APPENDIX D

Operating Experience

Operating Experience

Table D–1 1993–1998 Events Identifying Weaknesses in Voltage-Related Analyses, Tests, and Surveillance Procedures Affecting Plant Design and Administrative Controls

LER No. and Plant(s)	Event Date	Description of Event
289/98-010 Three Mile Island Unit 1	08/25/98	Due to the use of nonconservative impedance values, the plant's engineered safeguards buses could separate from the grid during single auxiliary transformer operation with a loss-of-coolant accident (LOCA). A procedure change was implemented to reduce the balance of plant loading during single auxiliary transformer operation.
275/98-010 Diablo Canyon Units 1 & 2	08/24/98	Degraded voltage relay trip setpoints drifted below required values. The design had not allowed adequate margin for setpoint drift. A design change was implemented to increase the setpoint margin and the relay settings.
293/98-015 Pilgrim	06/22/98	A potential low-voltage condition, coincident with a LOCA, may cause the core spray pump motor overcurrent relays to trip the motors. Analysis leading to relay setpoint changes and/or logic circuit modifications were stated to be the corrective action. Administrative controls were also added that required station operators to contact the regional grid operators once per shift to verify that the grid voltage is being maintained above the station minimum required level of 342 kV.
293/98-014 Pilgrim	06/22/98	A potential degraded grid voltage condition, coincident with a LOCA, may cause the emergency power to be restored later than is assumed in the design-basis accident analysis. Analysis leading to relay setpoint changes and/or logic circuit modifications were stated to be the corrective action.
302/98-002 Crystal River Unit 3	02/02/98	Insufficient administrative controls were established to ensure that an offsite power source would remain a qualified source of power. As a result of an NRC inspector followup item, the licensee found that the 500 kV backfeed was an unqualified offsite power source because there was no design calculation to support the 500 kV backfeed power source alignment. Subsequent calculation identified voltage and current loading limitations. Administrative controls were established to maintain 500 kV within acceptable limits.
423/98-006 Millstone 3	01/15/98	The degraded voltage relays and emergency diesel generator start relays had not been considered within response time tests required by the technical specifications.
293/97-015 Pilgrim	11/04/97	Salt service water pump motor overload settings were found to be too low for single salt service water pump operation with degraded voltage.

Table D–1 1993–1998 Events Identifying Weaknesses in Voltage-Related Analyses, Tests, and Surveillance Procedures Affecting Plant Design and Administrative Controls (Cont.)

LER No. and Plant(s)	Event Date	Description of Event
247/97-018 Indian Point Unit 2	07/26/97	Misoperation of switchyard relays resulted in load rejection and a unit trip. The unit overspeed resulted in a frequency between 68 and 73 hertz causing the ac motors, including the reactor coolant pumps (RCPs), to overspeed and increase flow. Subsequent investigation by Westinghouse found "gross tilting" of the reactor internals to be more limiting with respect to flow conditions. Westinghouse found that 115.8 percent reactor coolant system flow is more limiting than previously identified RCP speed of 125 percent. The recorded reactor coolant flow change was 15.7 percent and the total flow increased from 96.0 percent to 111.8 percent. Normally the load rejection should have generated an immediate bus transfer. However, the switchyard breaker alignment defeated the control logic that would cause a direct generator trip and bus transfer.
498/97-004 South Texas Units 1 & 2	03/19/97	During a review of surveillance procedures required by NRC Generic Letter 96-01, the licensee found that the surveillance testing procedures for the 4160 sustained degraded voltage and the degraded voltage coincident with safety injection did not adequately test all logic contacts to fully meet the surveillance requirements.
423/97-010 Millstone 3	01/29/97	The licensee identified a potential voltage condition that would not allow multiple plant systems to meet their design function. The worst-case minimum voltage values had not been used in 480-volt and 120-volt voltage calculations. Since the units were shut down, administrative controls were established to require monitoring of bus voltages to ensure that adequate voltages are maintained.
275/96-018 Diablo Canyon Units 1 & 2	11/21/96	As part of the review of voltage relay setpoint drift trends, the licensee concluded that a relay modification was needed.
395/96-006 Summer	07/11/96	Pursuant to 10 CFR Part 21, the licensee identified multiple failures of a relay over a 3-year period that were attributed to an integrated circuit in the relay. The relays are used in degraded voltage, loss of voltage, and RCP undervoltage reactor trip applications.
254/96-009 Quad Cities Units 1 & 2	05/23/96	The actual cable length was twice the cable length used in voltage analysis. Use of the correct cable length resulted in insufficient voltage to several safety-related motors
302/96-012 Crystal River Unit 3	04/11/96	The battery chargers have not have been qualified to operate within their specified range for ac voltage input.

Table D–1 1993–1998 Events Identifying Weaknesses in Voltage-Related Analyses, Tests, and Surveillance Procedures Affecting Plant Design and Administrative Controls (Cont.)

LER No. and Plant(s)	Event Date	Description of Event
277/96-002 Peach Bottom Units 2 & 3	01/26/96	During enhanced functional testing of the degraded voltage relays, station personnel determined that the trip settings had been slightly below their technical specifications allowable settings since 1994. The event was attributed to weak test procedures that did not specify the range and accuracy of the test equipment.
272/96-001 Salem Units 1 & 2	01/03/96	Analysis indicated that 36 thermal overloads were undersized because the original design had not fully considered installed ambient temperatures and degraded voltage conditions.
275/95-007 Diablo Canyon Units 1 & 2	08/08/95	The 230 kV system may not be able to meet its design requirements for all system loading conditions. Studies indicated that during peak loading, all lines and Morro Bay Power Plant Units 3 & 4 need to be in service to meet the Diablo Canyon plants' voltage requirements. Review of the voltage levels since 1990 found the voltage dropped below that required 19 times lasting 30 minutes, and 44 times lasting 72 hours.
266/95-004 Point Beach Units 1 & 2	03/28/95	The setpoints for the loss-of-voltage relays were not calibrated to the technical specification requirements because of an error in the setpoint document.
528/95-001 Palo Verde Unit 1	02/15/95	The plant voltage dropped below administratively imposed limits for 2.5 minutes because Energy Control Center personnel had not anticipated the severity of the Palo Verde switchyard voltage drop while removing a transmission line from service and lowering the VARS on Palo Verde Unit 1.
461/94-005 Clinton	04/08/94	Analysis of potential low-voltage conditions, coincident with a LOCA, concluded that the degraded voltage relay reset point of 3799 volts (90.5 percent of bus nominal voltage or 94.5 percent of motor nominal voltage) did not ensure sufficient voltages for all equipment at the 120-volt level.
249/94-005 Dresden Units 2 & 3	04/11/94	Multiple degraded voltage relays were out of calibration in a non-conservative direction. This was attributed to a defective power supply used in past testing and the past modification of the relay (LER 237/92-037) .
237/94-010 Dresden Units 2 & 3	04/12/94	As a result of a review initiated by an NRC inspection report, the licensee found that the minimum starting voltage for the high-pressure coolant injection room cooler fans was above the degraded voltage relay setpoint.
336/94-012 Millstone Unit 2	05/05/94	The failure of 6 out of 8 degraded voltage relay modules was caused by heat stress on an integrated circuit that causes premature failure.
446/94-006 Comanche Peak Units 1 & 2	05/26/94	The methodology and instrumentation did not result in adequate calibration of the degraded voltage relays.

Table D–1 1993–1998 Events Identifying Weaknesses in Voltage-Related Analyses, Tests, and Surveillance Procedures Affecting Plant Design and Administrative Controls (Cont.)

LER No. and Plant(s)	Event Date	Description of Event
341/94-003 Fermi 2	07/15/94	Test procedure deficiencies were discovered related to the comprehensiveness of undervoltage logic functional tests
331/94-012 Duane Arnold	10/04/94	On October 4 and upon recalibration on October 17, degraded voltage relays were found outside of voltage and time limits because of harmonic distortion of the ac power source during the calibration.
245/94-001 Millstone Unit 1	12/30/93	Analysis found that, under certain conditions a LOCA and a unit trip would result in a loss of offsite power (LOOP) to emergency buses 14E and 14F. With the switchyard voltage at the worst-case minimum value of 348 kV (Millstone 1 tripped and Millstone 2 & 3 offline/trip) the LOCA mitigation loads, in combination with the normal loads, which are not shed upon receipt of an accident signal, combine to produce a voltage drop that results in actuation of the relays that monitor for degraded bus voltage conditions.
219/93-005 Oyster Creek	09/09/93	Under certain conditions, degraded voltage may not allow some loads downstream of the 4160-volt buses to perform their intended safety function.
272/93-014 Salem Units 1&2	07/22/93	The 91.6 percent setpoint for degraded voltage relays would not fully protect the 230- and 460-volt motors.
155/93-005 Big Rock Point	07/14/93	The primary containment spray motor operator capability may have been insufficient to open under degraded voltage conditions. Under degraded voltage conditions, the voltage at the valve was calculated to be 50.2 percent versus its capability of 80 percent.
302/93-008 Crystal River Unit 3	07/06/93	The high-pressure injection suction valve may not be capable of performing its safety function under degraded voltage conditions. Analysis indicated that the valve may not have sufficient voltage to release its brake.
336/93-008 Millstone Unit 2	05/05/93	The charging pumps could have insufficient control power during a degraded voltage condition and could fail to start. The charging pumps have long lengths of cable that reduce the voltage available to the charging pump starting devices. In 1976, Millstone experienced a degraded voltage and the charging pumps did not start . At this time, transformer taps were adjusted to compensate for the reduced voltage without considering the long cable lengths.
237/93-005 Dresden Units 2 & 3	03/05/93	Sustained degraded voltage on the low-pressure coolant injection (LPCI) swing bus and 4-kV safety bus results in failure of both the LPCI and Division II core spray systems, causing an emergency core cooling response that is more limiting than the current licensing basis.

Table D–1 1993–1998 Events Identifying Weaknesses in Voltage-Related Analyses, Tests, and Surveillance Procedures Affecting Plant Design and Administrative Controls (Cont.)

LER No. and Plant(s)	Event Date	Description of Event
254/93-005 Quad Cities Units 1 & 2	03/05/93	Sustained degraded voltage on the LPCI swing bus and 4-kV safety bus results in failure of both the LPCI and Division II core spray systems, resulting in an emergency core cooling response that is more limiting than the current licensing basis.
528/93-011 Palo Verde Units 1, 2, & 3	01/14/93	The licensee found several substandard equipment voltage conditions as a result of the switchyard voltage being below its design basis minimum of 95 percent and the startup transformer fully loaded.
266/93-001 Point Beach Units 1 & 2	01/07/93	An evaluation indicated that the degraded voltage relay settings on the 4160-volt safety-related buses could be too low to provide adequate protection for safety-related equipment. A switchyard voltage of 351 kV (approximately 102 percent of nominal) or less causes the voltage at the 480-volt buses to be below the minimum required to ensure proper operation of the safety equipment. The degraded voltage relay setpoint was increased from 3875 volts, ± 2 percent to 3959 volts, ± 1/2 percent.
461/97-010-01 Clinton	04/08/92	In 1997, while reviewing surveillance procedures associated with degraded voltage, the licensee discovered that the procedure had not been updated to reflect the conservative minimum offsite voltage that was reestablished in 1994 as a result of a 1992 concern (LER 94-005). Review of previous offsite voltages found that the voltage had gone below the 1994 value and the licensee did not enter technical specification action statements.
461/97-035-01 Clinton	09/29/86	The battery chargers may not be capable of supplying full-rated voltage and current flow at the degraded voltage setpoint. The internal battery charger transformer taps were adjusted.
461/97-034-01 Clinton	09/29/86	During degraded voltage conditions, offsite power supply breakers could trip on undervoltage during transient electrical bus loading conditions associated with a block start of the LOCA loads. The design used improper cable resistance values and pump-motor brake horsepower ratings. A modification staggered the initial transient loading from the block loading.

Table D–2 Loss of Offsite Power Events that Followed a Unit Trip

LER No. and Plant(s)	Event Date	Description of Event
219/97-010 Oyster Creek	08/01/97	A LOOP followed a manual reactor scram. The cause of the LOOP was that the startup transformer's voltage regulator was set to control voltage at a level that was lower than the worst case assumed in the analysis. During transfer of the in-house loads to the startup transformer, the voltage dropped an expected 3-6 percent. When the plant trip occurred, the grid voltage dropped 4.5 percent because of heavy demand, and one of two 500 kV power supplies from the plant to the regional grid was out of service. The transformer's voltage regulator setting and the combined voltage drops were below the degraded grid relay setpoint.
219/89-015 Oyster Creek	06/19/89	A LOOP followed a reactor scram. An error by a maintenance technician tripped the main generator and caused a reactor scram. By design, control logic did not permit the auxiliary loads to transfer, causing a sustained undervoltage condition at the emergency buses.
395/89-012 Summer	07/11/89	A LOOP followed a reactor trip. In addition, three other generating stations tripped while attempting to compensate for the loss of V.C. Summer. As a result of the loss of four generating stations, the offsite voltage to the safety buses decreased below the minimum acceptable value. Peak load demand contributed to the grid disturbance.
311/86-007 Salem Unit 2	08/26/86	A LOOP (as defined by the licensee to be the loss of two out of three buses) followed a reactor trip. An undervoltage condition on two out of three vital buses was caused by the transfer of the nonsafety buses to the station power transformers and was aggravated by multiple transfers between the station power transformers. Block loading of safeguards equipment onto the vital buses contributed to the undervoltage.
272/83-033 Salem Unit 1	08/11/83	A LOOP followed a unit trip. Following a unit trip, a low voltage condition occurred on all Unit 1 vital buses associated with the transfer of the nonsafety-related buses to the station power transformers.

APPENDIX E

Accident Sequence Precursor Results for Grid-Related and Plant-Centered, Grid-Initiated Events

Table E–1 Accident Sequence Precursor Results for Grid-Related Events From 1980 To 1996

LER No. and Plant(s)	Event Date	Description	Conditional Core Damage Probability	Recovery Time (Minutes)
395/89-012 Summer	01/11/89	Grid – Instability	1.5E-04	130
251/85-011 Turkey Point 3	05/17/85	Grid – Multiple intense brush fires shorted out three transmission lines almost simultaneously	3.8E-05	156
251/85-011 Turkey Point 4	05/17/85	Grid – Multiple intense brush fires shorted out three transmission lines almost simultaneously	3.8E-05	125
331/84-028 Duane Arnold	07/14/84	Grid – Degraded Voltage	7.3E-05	1.0 (estimated)
312/81-034 Rancho Seco	06/19/81	Grid – High demand for load depressed switchyard voltage	5.2E-06	360
312/81-039 Rancho Seco	08/07/81	Grid – High demand for load depressed switchyard voltage	6.9E-06	180

Table E–2 Accident Sequence Precursor Results for Plant-Centered, Grid-Initiated Events From 1987 To 1996

LER No. and Plant(s)	Event Date	Description	Conditional Core Damage Probability	Recovery Time (Minutes)
313/80-022 ANO	06/24/96	Fault on one transmission line and overload of another	5.4E-06	1.0 (estimated)
334/93-013 Beaver Valley 1&2	10/12/93	Switchyard- human error (HE) caused dual unit trip	5.5E-05	15
327/92-027 Sequoyah 1&2	12/31/92	Grid configuration heavily contributed to dual unit trip	1.8E-04	95
270/92-004 Oconee	10/19/92	Switchyard-HE during battery restoration	2.1E-04	57
271/91-009 Vermont Yankee	04/23/91	Switchyard-HE during battery restoration	2.9E-04	277
369/91-001 McGuire	02/11/91	Switchyard -HE while testing circuit breaker	2.6E-04	40
249/89-001 Dresden	03/25/89	Switchyard-Circuit breaker fault	1.3E-05	45 (estimated)
456/88-022 Braidwood	10/16/88	Transmission line potential transformer failed at a remote location	1.8E-04	95
317/87-012 Calvert Cliffs 1&2	07/23/87	Faults on a transmission line from tree contact	4.8E-04	118

APPENDIX F

Risk Significance of Potential Grid Unreliability Due to Deregulation

Risk Significance of Potential Grid Unreliability Due to Deregulation

By Lee Abramson
Probabilistic Risk Analysis Branch
Division of Risk Analysis and Application, RES

It is concluded that the risk significance of potential grid unreliability due to deregulation is likely to be minimal for the average nuclear power plant (NPP), although individual NPPs might possibly exceed the station blackout (SBO) objective as a result of deregulation. From Reference 1, the SBO objective is that the contribution to overall core damage frequency (CDF) from SBO should not exceed 1E-5 per reactor year. From Reference 6, this objective was met by about 70 percent of the 54 plant units which estimated the contribution to CDF from SBO.

The basis for this conclusion is as follows:

Three studies have been published which deal with various aspects of assessing the projected risk from grid-related (GR) loss of offsite power (LOSP) events.

1. NRR has performed a parametric study (attached) which relates changes in the frequency and duration of LOSP events at a NPP to changes in the margin to meeting the SBO objective. The study demonstrated the feasibility of its approach by applying a simplified calculational tool to two plants, Surry and Clinton. Coupled with an assessment of the likely effects of grid deregulation on the frequency and duration of LOSP events, this approach can be used to estimate plant-specific changes in CDF due to grid deregulation.

2. Reference 2 predicts, based on expert judgment, multipliers for the frequency of GR-LOSP events and absolute blackout times at 17 NPPs as they might be affected by deregulation. Reference 2 also notes that the impact of deregulation is likely to occur over the next 5 years, but that “in the longer run, commercial pressures should force structural changes that would be assumed to increase reliability” (p. 16).

3. Reference 3 presents and analyzes data on the frequency and duration of GR-LOSP events at all U.S. NPPs for 1980-1996.

Based on the results of these studies, it is concluded that the risk significance of potential grid unreliability due to deregulation is likely to be minimal for the average NPP, although individual NPPs might possibly exceed the SBO objective as a result of deregulation. First, the effect on the average plant is examined. Taking account of the possible effects of deregulation and the individual characteristics of the plants, the frequency of GR-LOSP events at 17 NPPs around the country is predicted in terms of multipliers of the national average GR-LOSP frequency (Ref. 2). The average value of the 17 multipliers is 1.0. Assuming that the 17 multipliers are representative of all NPPs, this result implies that the GR-LOSP frequency of the average plant would not be affected by deregulation. Therefore, if grid deregulation had no effect on the recovery of LOSP, there would be no change in the grid-related risk of the average plant.

However, it is to be expected that an increase in grid unreliability will also lead to an increase in recovery time after a LOSP event and a resultant increase in risk. To assess the effect of this

change, it is necessary to estimate both the frequency of a GR-LOSP event at an average plant and the increase in the conditional core damage probability (CCDP) given a LOSP event.

Let F_{GR} = frequency of a GR-LOSP event
$\Delta CCDP_{GR}$ = change in the CCDP
ΔCDF_{GR} = change in core damage frequency.

Then $\Delta CDF_{GR} = (F_{GR})\ (\Delta CCDP_{GR})$. Equation (1)

Estimate F_{GR}: From Ref. 3, Table 3-4, six GR-LOSP events occurred in the period 1980-1996. Subsequent analysis by AEOD (private communication) has determined that one grid-related event was omitted in Ref. 3 and five LOSP events listed in Ref. 3 as plant-centered were actually grid-initiated. These six events are considered grid-related in this analysis, making a total of 12 GR-LOSP events in 1980-1996. From Ref. 3, Tables 3-1 and 3-2, 1188.8 and 455.5 unit-years of criticality and shutdown occurred, respectively, in 1980-1996. The frequency for the average plant in 1980-1996 was, therefore, 12/(1188.8+455.5) = 7.3E-3 per RY. Because there is no change expected in the GR-LOSP frequency for the average NPP due to deregulation, it is concluded that:

F_{GR} = 7.3E-3/RY.

Estimate $\Delta CCDP_{GR}$: In the event of LOSP, core damage will occur if all of the emergency diesel generators (EDGs) fail and if the time to recovery of offsite power exceeds the coping time of the plant. The probability of this latter event is called the nonrecovery probability.

Let PF_{EDG} = probability that all EDGs fail in the event of LOSP
ΔNRP_{GR} = increase in the nonrecovery probability due to grid deregulation.

Then $\Delta CCDP_{GR} = (PF_{EDG})\ (\Delta NRP_{GR})$. Equation (2)

Estimate PF_{EDG}: Because every plant has at least two EDGs, a conservative estimate of PF_{EDG} is given by the probability that neither of two EDGs will start and run if a GR-LOSP event occurs. Both EDGs are unavailable if (a) one is out for maintenance and the other fails or (b) both fail, either independently or due to a common cause. From Reference 4, the estimated EDG unreliability is 0.044, of which approximately 70 percent is attributed to maintenance; accordingly, a maintenance unavailability of 0.031 (70 % of 0.044) and an EDG failure probability of 0.013 (30% of 0.044) are assumed. From Table 4 of Reference 5, the common cause alpha factor for two EDGs failing to start is 0.0312 and failing to run is 0.0401; a conservative choice is the larger of these two values.

Accordingly, a common cause alpha factor of 0.040 is assumed. Combining these values:

PF_{EDG} = (maintenance & failure) + (two independent failures)
+ (independent failure & common cause)
$= 2(0.031)(0.013) + (0.013)^2 + (0.013)(0.040)$
= 1.5E-3.

Estimate ΔNRP_{GR}: For the 12 GR-LOSP events identified above, five had recovery times of 6 minutes or less and seven had recovery times between 118 and 360 minutes. It is reasonable to assume that grid deregulation will not significantly affect the recovery times of LOSP events like the five with very short recovery times, so that the nonrecovery probability for such events remains at 0. Accordingly, it is assumed that the nonrecovery probability can increase due to grid deregulation for only 7/12 = 58% of the GR-LOSP events. This fraction of 0.58 will be used as a weighting factor to estimate ΔNRP_{GR}.

Because the increase in the nonrecovery probability due to grid deregulation is clearly less than its value after deregulation, a conservative estimate of ΔNRP_{GR} is the nonrecovery probability after grid deregulation. Following Ref. 3, the distribution of recovery time is assumed to be lognormal. To account for variability between plants, recovery time, T_{rec}, is modeled as a product of two lognormals, T_b and T_w, where T_b is the distribution of the median recovery time over all plants and T_w is the distribution of recovery time about the median at any given plant.

Estimates of absolute blackout times as affected by grid deregulation are predicted for 17 plants in Table A.1 of Ref. 2. To determine T_b, these 17 values are considered medians of recovery times as affected by grid deregulation. Based on these values, T_b is lognormal with median = 78 minutes and error factor = 5.15.

Because T_w models recovery time about the median at a plant, the median of T_w is 1. A conservative estimate of its error factor is based on the observed recovery times associated with seven of the 12 LOSP events in 1980-1996, omitting the five events with very short recovery times (The error factor is conservative because the observed recovery times reflect between-plant as well as within-plant variability, while T_w accounts only for within-plant variability.) Based on four recovery times from Table 3-4 of Ref. 3 and an additional value of 118 minutes from the subsequent AEOD analysis, and after omitting correlated values in two cases where a LOSP event affected two plants at a site, the error factor of T_w is calculated as 2.07. Combining this value with the error factor of 5.15 for T_b, the error factor for T_{rec} is equal to 6.00. Furthermore, the median of $T_{rec} = T_b \bullet T_W$ is the product of the medians of its factors and is equal to (78)(1) = 78 minutes or 1.3 hours.

From the SBO rule, a plausible estimate for the coping time of the average plant is 4 hours. From the properties of the lognormal distribution, the probability that a lognormal with median m and error factor f exceeds x is equal to:

$$\Phi\ (\ 1.645\ [\ \ln\ (\ m\ /\ x\ )\ /\ \ln\ f\ ]\ )\ ,$$

where $\Phi\ (\ y\ )$ is the probability that a standard normal with mean 0 and variance 1 is less than y. Therefore, the probability that the recovery time modeled by T_{rec} exceeds 4 hours is equal to:

$$\Phi\ (\ 1.645\ [\ \ln\ (1.3\ /\ 4)\ /\ \ln\ (6.00)\ ]\ )\ =\ \Phi\ (\ 1.645\ [\ -0.627]\ )\ =\ \Phi\ (\ -1.032\ )\ =\ 0.15.$$

As explained above, this is multiplied by the weighting factor of 0.58 to yield:

$$\Delta NRP_{GR} = 0.087 \text{ for the average plant.}$$

Estimate ΔCDF_{GR}: Substituting the values for ΔNRP_{GR}, PF_{EDG} and F_{GR} into Equations (2) and (1) yields:

$$\begin{aligned} \Delta CDF_{GR} &= (7.3E\text{-}3/RY)\ (1.5E\text{-}3)\ (0.087) \\ &= 9.5E\text{-}7/RY. \end{aligned}$$

This value for the change in CDF for the average plant due to grid deregulation is an order of magnitude less than the SBO objective of 1E-5 per RY. It can be concluded that, except for plants which were very close to meeting the objective before deregulation, plants which met the SBO objective before deregulation would be likely to meet it after deregulation.

Outlier Plants: This analysis applies to the average NPP. It remains to examine the effect on plants which might be most affected by deregulation. Only 4 of the 17 multipliers for the GR-LOSP frequency are greater than 1.0 and the largest is 3.4 (Ref. 2, Table A.1). Taking this as the largest increase in F_{GR} for any plant, the largest increase in the GR-LOSP frequency (ΔF_{GR}) for any plant is:

$$\begin{aligned} \Delta F_{GR} &= 3.4F_{GR} - F_{GR} \\ &= (2.4)\ (7.3E\text{-}3/RY) \\ &= 1.8E\text{-}2/RY. \end{aligned}$$

From Equation (2), the largest change in the CCDP depends on the largest change in the nonrecovery probability, because PF_{EDG} is not affected by deregulation. Assuming $T_{rec} > 4$ with probability one, a bound on the largest change in ΔNRP_{GR} is given by the weighting factor of 0.58.

Multiplying these values for ΔF_{GR} , PF_{EDG} and ΔNRP_{GR} yields:

$$(1.8E\text{-}2/RY)\ (1.5E\text{-}3)\ (0.58) = 1.5E\text{-}5/RY.$$

This result is a conservative bound on the largest increase in CDF due to grid deregulation. Accordingly, it is possible that a plant which met the SBO objective before deregulation would not meet it after deregulation.

REFERENCES

1. A.M. Rubin, *Regulatory/Backfit Analysis for the Resolution of Unresolved Safety Issue A-44*, Station Blackout, NUREG-1109 U.S. Nuclear Regulatory Commission, June 1988, p. 37.

2. B.J. Kirby, et al., *Evaluation of the Reliability of the Offsite Power Supply as a Contributor to Risk of Nuclear Plants*, ORNL/NRC/LTR/98-12, Oak Ridge National Laboratory, August 1998.

3. C.L. Atwood, et al., *Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996*, NUREG/CR-5496, INEEL/EXT-97-00887, Idaho National Engineering and Environmental Laboratory, November 1998.

4. G.M. Grant, et al., Emergency Diesel Generator Power System Reliability, 1987-1993, INEL-95/0035, Idaho National Engineering Laboratory, February 1996.

5. F.M. Marshall, et al., *Common-Cause Failure Parameter Estimations*, NUREG/CR-5497, INEEL/EXT-97-01328, Idaho National Engineering and Environmental Laboratory, October 1998.

6. *Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance*, NUREG-1560, Vol 2., U.S. Nuclear Regulatory Commission, December 1997, p. 16-9.