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Final Report

Operating Experience Assessment-Effects of Grid Events on Nuclear Power Plant Performance

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ABSTRACT

Deregulation of the electrical industry has resulted in major changes to the structure of the industry over the past few years. Whereas before, a single unified corporation both produced the electricity and operated the distribution system, that is no longer the case. The industry has split into separate generating companies and transmission companies. Most nuclear power plant (NPP) operators no longer have control of the distribution system operations. NPPs rely on an outside entity to provide reliable electrical power for NPP operation. An assessment was completed by the Office of Nuclear Regulatory Research (RES) to identify changes to grid performance relative to NPPs which could impact safety. The assessment also provides some numerical measures to characterize grid performance before and after deregulation - in particular, those related to loss of offsite power (LOOP).

The information gathered provides a baseline of grid performance to gauge the impact of deregulation and changes in grid operation. The period 1985-1996 was considered “before deregulation” and 1997-2001 “after deregulation.” The assessment found that major changes related to LOOPs after deregulation compared to before include the following: 1) the frequency of LOOP events at NPPs has decreased, 2) the average duration of LOOP events has increased, 3) where before LOOPs occurred more or less randomly throughout the year, for 1997-2001, most LOOP events occurred during the summer, and 4) the probability of a LOOP as a consequence of a reactor trip has increased.

The assessment re-enforces the need for NPP licensees and NRC to understand the condition of the grid throughout the year to assure that the risk due to potential grid conditions remains acceptable.

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ABBREVIATIONS

ASP	accident sequence precursor
ATWS	anticipated transient without scram
BWR	boiling water reactor
CAISO	California Independent System Operator
CCDP	conditional core damage probability
CDF	core damage frequency
CFR	*Code of Federal Regulations*
CPC	core protection calculator
DAWG	Disturbance Analyses Working Group
DOE	Department of Energy
EDG	emergency diesel generator
EOC	end-of-cycle
EOOS	equipment-out-of-service
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FSAR	Final Safety Analysis Report
FTR	failed to run(load)
GDC	General Design Criterion
GL	Generic Letter
IN	Information Notice
INPO	Institute of Nuclear Power Operations
kV	kilo-volt
LER	licensee event report
LOOP	loss of offsite power
MTC	moderator temperature coefficient
MVAR	megavolt-ampere-reactive
MW	megawatt
MWt	megawatt-thermal

NEPA	National Energy Policy Act
NERC	North American Electrical Reliability Council
NPP	nuclear power plant
NRC	Nuclear Regulatory Commission, U.S.
OOS	out of service
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PNO	preliminary notification
PRA	probabilistic risk assessment
PWR	pressurized water reactor
RA	reserve auxiliary transformer
RCP	reactor coolant pump
RES	Nuclear Regulatory Research, Office of (NRC)
RIS	Regulatory Issue Summary
RPT	recirculation pump trip
RY	reactor year
SAT	startup transformer
SBCS	steam bypass control system
SBO	station blackout
SBO-CT	station blackout combustion turbine
TCV	turbine control valve
UPS	uninterruptible power supply
VOPT	variable over power trip

EXECUTIVE SUMMARY

Deregulation of the electrical industry has resulted in major changes to the structure of the industry over the past few years. Whereas before, a single unified corporation both produced the electricity and operated the distribution system, that is no longer the case. The industry has split into separate generating companies and transmission companies. Increased coordination times to operate the grid may result from involvement of more companies. In addition, generating companies have daily open access to the grid and this changes the grid design and operating configurations that were established before deregulation. Nuclear power plants (NPPs) rely on an outside entity to provide reliable electrical power for NPP operation. The Office of Nuclear Regulatory Research (RES) completed an assessment that is intended to identify changes to grid performance relative to the safety performance of NPPs. The assessment also provides some numerical measures to characterize grid performance before and after deregulation - in particular, those related to loss of offsite power (LOOP).

The information gathered provides a baseline of grid performance to gauge the impact of deregulation and changes in grid operation. The period 1985–1996 was considered “before deregulation” and the 1997–2001 “after deregulation.” The assessment found that major changes related to LOOPs after deregulation compared to before include the following: 1) the frequency of LOOP events at NPPs has decreased, 2) the average duration of LOOP events has increased – the percentage of LOOPs longer than four hours has increased from approximately 17 percent to 67 percent, 3) where before LOOPs occurred more or less randomly throughout the year, for 1997-2001, most LOOP events occurred during the summer, and 4) the probability of a LOOP as a consequence of a reactor trip has increased by a factor of 5 (from 0.002 to 0.01).

Simplified event trees were developed to assess the impact of these changes on overall NPP risk, and to include the impact of the LOOP as a consequence of reactor trip. The combined impact of the changes noted above, and the reduced frequency of reactor trips, was assessed. The findings include the following: 1) the average yearly risk from LOOPs and reactor trips decreased, 2) a small number of events over the first five years of deregulated operation indicates that most of the risk from LOOPs occurs during the summer, and 3) including LOOP as a consequence of a reactor trip and the potential for degraded grid during the summer, the risk associated with an emergency diesel generator (EDG) out of service can be larger than previously realized.

The assessment re-enforces the need for NPP licensees and NRC to understand the condition of the grid throughout the year to assure that the risk due to potential grid conditions remains acceptable. To elaborate:

(1) The NRC does not regulate the grid; however, the performance of offsite power is a major factor for assessment of risk. With respect to maintaining the current levels of safety, offsite power is especially important with regard to the risk associated with EDG maintenance and outage activities. Consequently, NRC and licensee assessments of risk that support EDG maintenance and outage activities should include: (a) assessment of offsite power system reliability, (b) the potential for a consequential LOOP given a reactor trip, and (c) the potential increase in the LOOP frequency in the summer (May to September). Regarding (a) above, the assessment of the power system reliability and risks from plant activities can be better managed though coordination of EDG tests with transmission system operating conditions.

(2) Another important aspect of the changes to the electrical grid is the impact on the electrical analyses of NPP voltage limits and predictions of voltages following a reactor trip and whether a reactor trip will result in a LOOP. Recent experience shows that actual grid parameters may be worse than those assumed in electrical analyses due to transmission system loading, equipment out-of-service, lower than expected grid reactive capabilities, and lower grid operating voltage limits and action levels. NPP design basis electrical analyses used to determine plant voltages should use electrical parameters based on realistic estimates of the impact of those conditions.

(3) With the structural and operational changes that have occurred in the industry, it is important to have mechanisms, such as contracts between the NPP and transmission company, in place to ensure that grid operators will provide reliable electrical power. Some regional grid operating entities manage and control operational and engineering activities in real time to maintain grid availability and reliability. Since external factors impact the ability of licensees to manage risks and understand the condition of the grid, some NPP licensees have implemented contractual agreements with grid operators to provide a mechanism for maintaining secure electrical power in the deregulated environment. Contractual arrangements should include specific electrical requirements, communication protocols, operating procedures and action limits, maintenance responsibilities, station blackout (SBO) (alternate ac) power supply responsibilities, and NPP and grid. Within its proper roles and responsibilities, the NRC should communicate with the industry about the possible need for these mechanisms.

CAISO, PJM, and Callaway experience provides an opportunity for the industry and NRC to develop lessons to be learned. The assessment identified the following insights from this experience:

(1) While the data set is small, recent experience indicates that the average duration of LOOPs has increased. Based on historical data, power restoration times following a LOOP are assumed to be less than 4 hours; most recent LOOPs have lasted significantly longer.

Also, recent grid events, although not directly associated with LOOPs, indicate that grid recovery times may be longer. For example, in the Northeast, it took the grid operator (of 12 NPPs) 10 hours to resolve problems from unexpected behavior of the grid, despite implementation of planned voltage and load management programs and investigation found insufficient reactive capacity to quickly restore voltages. In the Mid-West, the grid operator needed 12 hours to change regional power flows and restore voltage to a NPP. These events support the concern identified in SECY 99-129 that the time needed to coordinate grid operations may increase in a deregulated environment.

(2) LOOPs, partial LOOPs, momentary LOOPs, and voltage degradations below the technical specification low limit following or coincident with a reactor trip may provide indication of a potential electrical weaknesses in the grid and a need for regulatory followup to prevent more serious events. In some events, plant equipment which control safety bus voltage levels, is assumed to be functional by the grid controlling entity for the range of external voltages maintained at the NPP. Periodic verification of NPP or other voltage controlling equipment operability may require compensatory measures such as a request for voltage adjustment from the grid control entity.

(3) Realistic assessment of the risk from grid events may need to consider the impact of a grid event on multiple NPPs. For example, one recent transmission system disturbance resulted in the simultaneous trip of four NPPs.

(4) Experience indicated that transmission system operation or disturbances may cause sustained or frequent current unbalances that result in damage to electrical equipment. It is common practice to protect expensive or important nonsafety equipment from current unbalances. Safety equipment does not always have the same level of protection. RES will further analyze this issue in the future.

(5) Grid-induced reactor transients can affect scram capability. Operating experience identified an instance where anticipated transient without scram mitigation based on end-of-cycle recirculation pump trip logic failed to operate correctly during a transmission system fault that produced large electrical load fluctuations. RES will further analyze this issue in the future.

(6) Grid conditions which result in over-frequency conditions can have unexpected consequences. At one plant, over-frequency conditions following a load rejection caused speed-up of the reactor coolant pumps which generated lifting forces on the core to within a small margin of causing core mechanical tilt. The over-frequency condition was not properly accounted for by the plant protective relay control logic. RES will further analyze this issue in the future.

(7) The synergistic effects of reduced reactive grid capability on the NPP from hot weather and multiple reactor power uprates should be evaluated. RES will further analyze this issue in the future.

1 INTRODUCTION

Deregulation of the electrical industry has resulted in major changes to the structure of the industry over the past few years. Whereas before, a single unified corporation both produced the electricity and operated the distribution system, that is no longer the case. The industry has split into separate generating companies and transmission companies. More companies are likely to lead to increased coordination times to operate the grid. In addition, generating companies have daily open access to the grid and this changes the grid design and operating configurations that were established before deregulation. Nuclear power plants (NPPs) rely on an outside entity to provide reliable electrical power for NPP operation.

The Nuclear Regulatory Commission (NRC) Office of Nuclear Regulatory Research (RES) completed the work described in this report to identify and provide an assessment of grid events at NPPs before (1985-1996) and after deregulation (1997-2001). . The objectives of the work were to use accumulated operating experience from various sources to identify and assess (1) the numbers, types, and causes of these events, (2) potential risk-significant issues (3) potential challenges to the effectiveness of the NRC regulations, and (4) lessons learned. This assessment is intended to identify changes to grid performance relative to NPPs which could impact safety. The assessment also provides simplified numerical measures to characterize grid performance before and after deregulation - in particular, those related to loss of offsite power (LOOP). The information gathered provides a baseline of grid performance to gauge the impact of deregulation and changes in grid operation

For the purposes of this assessment, grid events include (1) losses of electric power from any remaining power supplies as a result of, or coincident with, a reactor trip, (2) reactor trips, losses of offsite power (LOOPs), or partial LOOPs in which the first event in the sequence of events occurred in the transmission network, i.e. the NPP switchyard or the transmission and generation system beyond the NPP switchyard, and (3) “events of interest” that provide an insight into the plant response to a grid initiated event.

Since our focus is on aspects of grid performance, some events are defined differently here than in other assessments - a number of the events which are defined in this assessment as grid related LOOPs or grid initiated based on transmission network equipment failures, personnel errors, or dependence on grid operator for recovery, are referred to in other event studies as plant-centered. For the purposes of this assessment a reactor trip from full power operation is a random test of the capacity and capability of the grid, and as such a LOOP as a consequence of a reactor trip may be a grid-related LOOP.

As an overview, Section 2 , “Background,” provides basic information necessary to understand the work. Section 3, “Discussion,” provides the analyses and discussion to satisfy the objectives of the work. The numbers, types, and causes of these events were developed from Appendix A, “Grid Events,” as as explained in Section 3.1. Analysis of these events identified some grid related LOOPs that were potentially risk-significant. These risks were assessed in Section 3.2 by comparing the risks from all LOOP events before and after deregulation on an equal basis using Appendix B, “Event Trees,” and actual operating data which were gathered in Appendix C, “LOOP and Scram Data, 1985-2001.” Sections 3.2 to 3.8 provide risk insights and lessons learned and end with assessments that are consolidated in Section 4, “Assessment.”

2 BACKGROUND

The NPP offsite power system is the “preferred source” of ac electric power, often referred to as the grid. The safety function of the offsite power system is to provide power to ac safety loads required to shut down the NPP, including loads in the reactor core decay heat removal system that are required to preserve the integrity of the reactor core and containment following a reactor trip. For the purposes of this assessment, the grid includes the switchyard or substation at the NPP, the offsite generating and transmission systems, and the offsite loads. Redundant onsite ac emergency power supplies, usually emergency diesel generators (EDGs), automatically provide power to the safety buses following a LOOP.

2.1 Principal Design, Operating and Maintenance Criteria and Risks

The NRC has no jurisdiction over the grid. However, NRC regulations and NPP Technical Specifications (TS) provide controls over the licensing bases, design criteria, NPP activities, and risks relative to the grid as discussed below. .

2.1.1 Principal Offsite Power System Design and Reliability Criteria

The principal design criteria for the licensing basis of the offsite electric power system are set forth in Appendix A Title 10 of the U.S. Code of Federal Regulations, Part 50, “Domestic Licensing of Production and Utilization Facilities” (10 CFR Part 50) (Ref. 1)

General Design Criterion (GDC) 17,"Electric power systems," of Appendix A states in part, that

> An onsite electric power system and an offsite electric power system shall be provided....The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability....
>
> Provisions...to minimize the probability of losing electric power from any of the remaining supplies as result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of a power from the transmission network, or the loss of power from the onsite electric power supplies.

Common capacity and capability terms are power, voltage, and frequency. While a detailed electrical engineering discussion of these terms is beyond the scope of this report, it suffices to understand that power has two components, real and reactive, measured in megawatts (MW) and megavars (MVAR), respectively. The real power flow between two points depends primarily on the relative voltage phase angles. The reactive power flow is a direct function of the difference in the magnitude of the voltage at these points.

The GDC 17 requirements are intended to ensure that the NPP connects to a sufficiently robust and reliable grid. The GDC 17 provisions to minimize the probability of losing electric power is a common design practice for any generating plant. The industry uses the same measures as GDC 17 to define grid reliability. The North American Electric Reliability Council (NERC), an industry organization that promotes and assesses grid reliability, defines grid reliability 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 amount of reserve power available to provide uninterruptible power. Grid operating entities maintain “spinning reserves” synchronized to the grid for immediately use. Voltage reductions and interrupting loads (rolling blackouts) also help to maintain reserves. The security of the transmission system is defined in terms of the ability of the system to withstand sudden disturbances, such a reactor trip or transmission line fault, and is measured by the power restoration time to a particular group of customers. Spinning reserves, and voltage and load management programs are important factors for grid operators to maintain system stability, adequate NPP voltages and frequencies, and recover from grid events in a timely manner.

The capacity and capability of the offsite power system are ensured through analyses (discussed in Section 2.4) that are part of the licensing bases. The NRC Standard Technical Specifications (TS) (Ref. 2), which are typical of NPP TS, provide for verification of the availability of the offsite power supplies every 7 days. The TS impose limiting conditions of operation (LCO) including shutdown of the reactor should offsite power not be restored in a timely manner, typically in times up to 72 hours for loss of individual offsite power supplies and shorter times for loss of multiple offsite power supplies. The NRC TS states that the operability of ac electrical considers the capacity and capability of the remaining sources, reasonable time for repairs, and the low probability of a design basis accident occurring in this period. Continued operation for 72 hours generally requires, consistent with Regulatory Guide 1.93, “Availability of Electric Power Sources,” 1974, that licensees assess that system stability and reserves are such that a single failure (including a reactor trip) would not cause a LOOP.

2.1.2 Principal Risks and Regulatory Expectations

Section 50.63," Loss of All Alternating Current Power," is commonly referred to as "the station blackout rule." A station blackout (SBO) is defined in Section 50.2 as the “complete loss of electric power to the essential and nonessential electric switchgear buses in an NPP (i.e., a LOOP concurrent with a turbine trip and unavailability of the emergency ac power system)."   The SBO rule requires that NPPs be capable of withstanding an SBO by maintaining core cooling for a specified duration (coping time) and recover from the SBO event. The principle parts of SBO accident sequence are: (1) the initiating LOOP-the frequency of a LOOP (2) the loss of onsite power-the unreliability of the onsite ac emergency power supplies and common cause failure unreliability, (3) recovery-the likelihood that ac power will be restored before the core is damaged, and (4) core damage probability - the sequences that result in core damage from the failure to recover ac power and consequently, the failure of decay heat removal or support systems necessary to safely shutdown. Core cooling failures, or loss of reactor core cooling integrity can occur in 1 to 2 hours. Failures can also occur in 4 to 8 or more hours from support system failures (e.g. batteries, compressed air, HVAC) or design limitations (e.g. high suppression pool temperatures).

The SBO rule was based on NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants," dated June 1988(Ref. 3). According to NUREG-1032, the estimated range for the frequency of core damage as a result of an SBO accident is 1E-6 to 1E-4 per reactor-year (RY). NUREG-1032 focused on the reliability of the onsite power system based on the judgement that it would be easier to implement modifications, if required, on the onsite power system rather than the grid.   NUREG-1032 stated that offsite power system reliability was dependent on a number of factors, such as repair and restoration capability, that were difficult to analyze and control.

An RES report, "Regulatory Effectiveness of the Station Blackout Rule," dated August 15, 2000 (Ref. 4) assessed if the SBO rule achieved the desired outcome. The RES report compared the risk reduction expectations from SBO rule implementation as established in NUREG-1109, "Regulatory/Backfit Analysis for the Resolution of the Unresolved Safety Issue A-44, 'Station Blackout," June 1988 to the estimated risks from an SBO as documented in the licensee probabilistic risk assessments (PRA). The RES report shows that SBO rule implementation resulted in a risk reduction in the mean SBO core damage frequency (CDF) of 3.2E-05 per reactor year (RY), slightly better than the 2.6E-05/RY expected.

NUREG-1032 concludes that "the capability to restore offsite power in a timely manner (less than 8 hours) can have a significant effect on accident consequences." NUREG-1032 studied LOOP event frequency and duration data in three categories to i.e., plant-centered, weather-related, and grid-related events and found the median recovery times to be 18, 210, and 36 minutes respectively, based on data from 1968 through 1985. NUREG-1032 found the overall median recovery time to be 36 minutes.   NUREG-1032 data shows that prior to SBO implementation, of the 59 LOOPs at power which were identified, only four (7%) were more than four hours; one was a grid event, three were weather related events, and the longest plant related event was 165 minutes. NUREG-1032 expected "enhanced recovery times" for grid related and severe weather LOOPs based on the availability of plant recovery procedures and at least one source of ac power.

NUREG-5496, “Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996,” dated June 1998 (Ref. 5) found the median recovery times to be 20, 204, and 140.5 minutes for plant-centered, weather-related, and grid-related events. NUREG-5496 found the overall median recovery time for LOOPs at power to be 60 minutes. More specifically, NUREG-5496 identified six grid-related LOOPs from 1986 to 1989 with a median recovery time of 140 minutes and no grid-related LOOPs from 1990 to 1996. NUREG-5496 found that up to 1996, the number of grid-related LOOPs was quite low and the recovery times were longer but the data set was small; the executive summary concluded that the recovery times for SBO type events were well below the minimum SBO coping time.

2.1.3 Control of Risks From Running EDG Tests To The Grid

EDGs are periodically tested (monthly) to the grid one at a time, for 60 minutes, and approximately every 18 months for 24 hours, as specified in the TS. NRC Standard TS surveillance requirements bases state that testing one EDG at a time avoids common cause failures that might result from offsite circuit or grid perturbations. The 60 minute run stabilizes engine temperatures, while minimizing the time the EDG is connected to the offsite source. The Standard TS notes that the 24 hour test is not performed with the reactor at power but may be performed to reestablish operability provided an assessment determines the safety of the plant is maintained or enhanced. The TS bases state the assessment shall consider potential outcomes and transients associated with a perturbation of the offsite or onsite system when tied together and measure these risks against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the surveillance is performed while at power.

10 CFR 50.65, “ Requirements for monitoring the effectiveness of maintenance at nuclear power plants,” commonly referred to as the “maintenance rule,” requires licensees to assess and manage risk when performing maintenance activities as follows:

> (a)(4) Before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventative maintenance), the licensee shall assess and manage the increase in the risk that may result form the proposed maintenance activities. The scope of the assessment may be limited to structures, systems, and components that a risk-informed evaluation process has shown to be significant to public health and safety.

NRC Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants, May 2000 (Ref. 6) provides guidance on implementing the provisions of 10CFR50.65 (a)(4) by endorsing Section 11 to NUMARC 93-01, “Nuclear Energy Institute Industry Guideline For Monitoring The Effectiveness of Maintenance At Nuclear Power Plants, February 22, 2000 (Ref. 7). Section 11 to NUMARC 93-01 addresses offsite power in several areas. For example, Section 11.3.2.8 states “Emergent conditions may result in the need for action prior to conduct of the assessment, or could change the conditions of a previously performed assessment. Examples include ......or significant changes in external conditions (weather, offsite power availability).”

2.2 Reactor Trips Degrade the Grid and Result in Regulatory Actions

All reactor trips from full power operation are a random test of the capacity and capability of the grid and as such are potentially grid-related events. Under GDC 17 the grid should have sufficient capacity and capability to allow the NPP to pass this test. When a reactor trips, the voltage in the vicinity of the NPP drops from the loss of NPP main generator reactive power supply and the additional loading from the transfer of the NPP loads to the grid. The voltage normally recovers quickly as “spinning reserves” and other reactive power supplies immediately supply power. LOOPs, partial LOOPs, momentary LOOPs, and voltage degradations below the plant specific low limit following or coincident with a reactor trip are evidence of a potential electrical weaknesses in the grid.

The NRC took generic actions consistent with GDC 17 after two reactor trips in summer months resulted in degraded NPP voltages below the levels needed to respond to a design basis event. One of the events involved two occurrences, two weeks apart, in July 1976 at a NPP in the Northeast. In the first occurrence, when the reactor tripped the 345 kV voltage dropped approximately 5% from 352 kV to 333 kV for one hour. This voltage reduction along with the voltage drops through the NPP transformers, reduced the voltage at safety related equipment to levels that were insufficient to operate the equipment. In addition, certain non-safety related equipment did not start due to blown fuses. Corrective action included raising undervoltage relays setpoints to assure the plant would be separated from a degraded grid before the voltage dropped to a point where equipment operability could no longer be assured.

A few weeks later, the inrush current from the start of a non-safety 1500 horsepower motor resulted in low voltage and the EDGs automatically started and loaded. However, during automatic load sequencing the inrush current from safety motor starts caused the bus voltage to drop below the new undervoltage setpoints. The CCDP for this event was 1.4E-02 due to the lack of plant procedures to respond to the event. This event resulted in an NRC generic letter (not numbered at the time) dated June 2, 1977 (referenced in ref. 8) requiring licensees to add degraded voltage relays to trip the offsite power supply to safety buses and start the emergency onsite power supplies at or above the calculated minimum voltage levels needed to withstand a design basis event.

The second reactor trip occurred in September 1978 at a dual unit NPP. When the reactor tripped, the transfer of the station loads tripped a transmission system auto-transformer that was already feeding the other NPP's station power transformer. The loads from both NPPs transferred to, and overloaded, a "back-up" NPP transformer. Power was restored in approximately 88 minutes and the CCDP was less than 1.0E-06. The licensee's review of the event found that degraded voltage conditions would result at the safety buses following a design basis event and that the safety loads might not transfer to the EDGs. After this his event, the NRC issued Generic Letter (GL) 79-36, "Adequacy of Station Electric Distribution System Voltages," August 8, 1979 (Ref. 8) which expanded the NRC review of the adequacy of the electric power system to include the results of plant-specific analysis using NRC guidelines for voltage drop calculations.

The GL 79-39 guidelines for voltage drop calculations require licensees to consider a reactor trip and the "minimum expected "and" maximum expected grid voltage as follows:

> Separate analyses assuming the power source to the safety buses is ... (c) other available connections to the offsite network one by one assuming the need for electric power is initiated by (1) an anticipated transient (e.g, unit trip) or (2) an accident, whichever presents the largest load demand situation.
>
> The voltage at the terminals of the safety loads should be calculated based on....the assumption that grid voltage is at the "minimum expected value" ....and selected based on the least of the following: (a) The minimum steady-state voltage experienced at the connection to the offsite circuit. (b) The minimum voltage expected at the connection to the offsite circuit due to contingency plans which may result in reduced voltage from the grid. (c)The minimum predicted grid voltage from grid stability analysis (e.g. load flow studies).
>
> Provide assurance the actions to assure adequate voltage levels for safety loads do not result in excessive voltage, assuming the maximum expected value of voltage at the connection of the offsite circuit...
>
> ....requests licensees to state planned actions including any LCO for TS in response to experiencing voltages below analytical values.

2.3 Nuclear Power Plant Voltages Based on Grid Electrical Parameters

The North American electric power supply grid consists of four nearly independent large major areas that are interconnected. Approximately 160 control centers perform the load dispatching and switching operations. Current flows freely within this system according to the laws of electricity. The grid operating or transmission entity analyzes this system for stability, short circuits, load flows, and voltages to ensure that the grid security is maintained. Typically, thousands of grid operating configurations are analyzed, assuming numerous initial conditions, such as the availability of the generators, sudden loss of the large generators or loads, the minimum and peak transmission system loading, equipment out of service (EOOS), and faults.

The results of the grid analyses are typically summarized for the NPP in terms of the minimum and maximum expected voltages and impedances at the high-voltage terminals of the NPP power transformers. The NPP uses these parameters to calculate whether NPP internal voltages are within equipment ratings and the minimum voltages using the GL 79-36 guidelines. Licensees periodically revise these analyses with updated external voltages and impedances from the grid operating entity. If the NPP internal voltages are not adequate, i.e expecting that a unit trip or other condition would result in operating voltage too close to the degraded voltage relay and alarm setpoint, the licensees and grid operating entity may adjust their systems (e.g. move NPP or grid transformer voltage taps) or establish compensatory measures (e.g. procedure revisions) to avoid potentially adverse conditions or configurations. In some cases, the NPP or the grid operating entity may need to add equipment such as a transformer with an automatic load tap changer or capacitors.

2.4 Effects of Deregulation of the Electric Power Industry on Nuclear Power Plants

In 1992, the National Energy Policy Act (NEPA) encouraged competition in the electric power industry. NEPA requires, in part, open generator access to the transmission system and statutory reforms to encourage the formation of wholesale generators. The electric industry began deregulating after the April, 1996 issuance of 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,” which requires that utility and nonutility generators have open access to the electric power transmission system. A detailed state-by-state status is available on a Department of Energy website and shows about 50% of the state utility regulatory commissions have or plan to deregulate, and 50% have no plans to deregulate or have put deregulation on hold.

Prior to economic deregulation of the electrical system, NRC licensees were both electrical generators and transmission system operators. Initial licensing of NPPs included analyses of electrical system performance with certain contingencies to assure reliable offsite power. With economic deregulation, NRC licensees no longer control the transmission system - typically, generation and transmission are separate corporations.

Deregulation is of interest to the NRC. The appendices of NRC, “Strategic Plan, Fiscal Year 2000 - Fiscal Year 2005,“ October 4, 2000 (Ref. 8) note that one of the major external factors that could significantly affect achievement of Strategic or Performance Goals is the ongoing economic deregulation and restructuring of the electric power industry. The NRC has not asked its licensees to analyze electrical system performance under the current conditions, however, SECY-01-0044, “Status of Staff Efforts Regarding Possible Effects of Nuclear Industry Consolidation on NRC Oversight,” March 16, 2001 (Ref. 9) recommends in the area of grid stability and reliability issues that the staff monitor the developments unfolding in different parts of the country and continue the current efforts to assimilate information.

An RES study, “The Effects of Deregulation of the Electric Power Industry on The Nuclear Plant Offsite Power System: An Evaluation,” dated June 30, 1999 (Ref. 10) was the basis for the information in SECY 99-129 in response to Commissioners’ questions. The RES study was based on NPP operating experience, the staff’s review of NERC reliability forecasts, visits to 17 grid control entities, and the actions of two licensees with the California Independent System Operator (CAISO). The RES study and SECY 99-129 identified the potential impacts of deregulation of the electric industry on grid reliability that are relevant to this assessment:

- The risk from the potential grid unreliability due to deregulation is likely to be minimal, although individual plants might have an increase in the CDF due to deregulation of as much as 1.5E-05/RY.

- The grid design and operating configurations were established before the electric power industry was deregulated to ensure the correct voltages on the grid and at NPPs. Failure to analyze and reconfigure the grid under changing conditions could result in abnormal voltages or frequencies at the NPPs. Deregulation may result in unanalyzed grid operating configurations because open access to the transmission system changes the current flows and voltages throughout the grid according to fundamental (Kirchoff’s) laws of electricity. Today more blocks of power are being transmitted over greater distances; and grid operating entities not in involved the power transaction may see their operation disrupted by unexpected power flows. Predicting the amount and path of the current and power and the voltages throughout the grid requires analyses.

- The duration of a LOOP or a SBO may increase. Changes in ownership and control of generation and transmission facilities adds to the number of entities that must be coordinated and is likely to increase recovery times following a grid disturbance.

The NRC issued Information Notice (IN) 98-07, “Offsite Power Reliability Challenges From Industry Deregulation,” February 27, 1998” (Ref. 11) to alert licensees to the potential adverse effects of deregulation of the electric power industry on the reliability of the offsite power source. The NRC also issued IN 2000-06: “Offsite Power Voltage Inadequacies,” March 27, 2000 (Ref. 12) to inform licensees of events that caused concerns about the voltage adequacy of offsite power sources.

At an industry/NRC meeting on May 18, 2000 (Ref. 13) the industry discussed the initiatives of the Pennsylvania, New Jersey, Maryland (PJM) Nuclear Owners/Operators (grid operator for 12 NPPs), the California ISO (grid operator for 8 NPPs), and the Institute of Nuclear Power Operations (INPO) to help maintain GDC 17, the SBO rule, and technical specification compliance in a deregulated environment. The industry initiatives include a plant-by-plant review to ensure each NPP has established appropriate interface with the grid operator, verified procedural adequacy for a LOOP or degraded grid, verified responsibility for NPP and switchyard high voltage equipment maintenance, confirmed the validity of grid reliability and design assumptions and the degraded voltage trip settings, and trained operators; these actions were detailed in a letter from the Nuclear Energy Institute (NEI) to the NRC on June 26, 2000, “Electric Grid Voltage Adequacy. (Ref. 14)” A followup meeting was held on October 27, 2000 (Ref. 15) to discuss the status of industry activities, the Electric Power Research Institute (EPRI) Power Delivery Initiative to develop tools to enhance grid reliability, and the agenda for an industry workshop “Grid Reliability Workshop” that took place in April, 2001.

The NRC issued Regulatory Issue Summary (RIS) 2000-24, “Concerns About Offsite Power Voltage,” December 21, 2000 (Ref. 16) to inform addressees of concerns about grid reliability challenges as a result of industry deregulation, potential voltage inadequacies of offsite power sources, and actions the industry had committed to address this issue. The RIS also stated that the NRC is continuing to work with the nuclear power industry to address this matter and acknowledged that the Nuclear Energy Institute would take the following steps as an industry initiative: (1) provide guidance to utilities on the need for, and acceptable techniques available to ensure, adequate post-trip voltages; (2) establish provisions to log and evaluate unplanned post-trip switchyard voltages to help verify and validate that the intent of Item 1 is met; and(3) determine plant-specific risks of degraded voltage and double sequencing scenarios.
The NRC is periodically reviewing the status of industry initiatives under RIS 2000-24. The industry and the NRC met on March 15, 2002 (Ref. 17) to discuss the status of industry INPO, EPRI, CASIO, and PJM activities. The industry concluded that their initiatives verify that barriers are in place to ensure NPPs are protected from a degraded grid; however, the details of plant specific results are not available to the NRC.

3.0 DISCUSSION

For purposes of this work, since our focus is on aspects of grid performance, some events are defined differently here than in other assessments - a number of the events which are defined in this assessment as grid related LOOPs are referred to in other event studies, which had a different focus, as plant-centered. These aspects are discussed below.

The executive summary of NUREG-5496, which estimates the LOOP frequency and duration based on operating experience from 1980–1996 states "...For this study, the event was considered an initiating event if the LOOP caused the reactor to trip or if both the LOOP and the reactor trip were part of the same plant transient, resulting from the same root cause. It was not an initiating event if either no reactor trip occurred, or the cause of the reactor trip did not directly cause the LOOP event, but the reactor trip subsequently caused the LOOP event. All events included in this study are LOOP events, but only the initiating events were used in the frequency analysis."

Consider the following example. An event initiated by a turbine trip which resulted in a LOOP would be considered a plant-centered event in most instances. However, if the reason that the plant disconnected from the grid following the turbine trip was that the grid voltage decreased below the undervoltage relay settings because of the loss of the plant's own generating capacity or grid voltage or loading conditions at the time of the turbine trip, for our purposes, this event is considered grid related. One of the goals of GDC 17 is to assure that a plant trip will not result in a LOOP. If due to lack of capacity or capability to withstand a sudden disturbance, the grid is in a condition such that the lost generation due to the NPP trip causes conditions which lead to a LOOP, our interpretation is that the LOOP is grid related. For purposes of this assessment, the initiating event may be a turbine trip, but the root cause of the LOOP is the degraded condition of the grid.

This distinction may be important from a risk perspective. Although some licensees risk analysis may consider the potential for a reactor trip to cause a LOOP; licensee risk analysis often consider a reactor trip and a LOOP to be independent events. The typical risk analysis considers a reactor trip and a LOOP to be independent events - the probability of a LOOP is not impacted by the reactor trip. However, if the grid is in a condition such that a loss of generation leads to degraded voltage and a consequential LOOP, the risk impact of a reactor trip would be greater. Also power restoration, which is important from a risk perspective, is also dependent on grid operator direction and action following grid initiated event-for our purposes it is planned to investigate if this time is increasing or decreasing.

Consider another example. It is generally assumed that a reactor trip will not lead to a LOOP at a different NPP. However, if grid conditions are such that loss of generating capacity from a NPP trip leads to degraded voltage and a LOOP at another site or plant, the LOOP is considered to be grid related. Again, the risk implications of a reactor trip would be greater, particularly if several units are affected.

The risk impact of grid related events may be underestimated due to the classification of events as plant centered when the root cause relates to the ability of the grid to maintain adequate electrical power following a reactor trip.

3.1 Methods for Data Collection and Risk Analyses

For the purposes of this assessment before deregulation was assumed to be 1985–1996 and after deregulation was assumed to be 1997–2001. As 1997 was first full year of NPP operation with the grid deregulated it was selected as the starting point for deregulation; in April 1996, FERC Order 888 required that generators have open access to the transmission system.

To be consistent with other NRC assessments, this assessment considered an event to be a LOOP when all available EDGs started and loaded. A partial LOOP was indicated by the start and loading of one or more, but not all the EDGs.   Momentary LOOPs and partial LOOPs were indicated by the start of the EDGs; however, the voltage quickly recovered so the EDGs did not load. Partial or momentary LOOPs are generally not risk significant unless complications set-in; however, they helped to identify potential NPP sensitivities to a grid-related event.

Appendix A, provides summaries of grid events that affected NPP performance from 1994 through 2001. Although deregulation did not start until 1997, RES selected 1994 as a starting point for the collection of events; RES was aware of least one grid entity that used 1994–1996 grid events that affected its NPPs, in part, to obtain the lessons learned for its future operation in a deregulated environment, so it was judged RES should do the same. The events were identified and summarized from licensee event reports (LERs) in the NRC Sequence Coding and Search System, NRC inspection reports, NRC preliminary notification (PNO) reports, NERC Disturbance Analysis Working Group (DAWG) reports, and CAISO and PJM reports, which are discussed below. The LER, PNO, and DAWG event dates were cross-referenced to identify the events affecting multiple NPPs. It is emphasized the CAISO and PJM reports were used not to be critical, but to gain insights; these entities are proactive with comprehensive programs and actions for the operating large, robust grids in a deregulated environment.

The DAWG reports helped identify when the NPP event was part of a larger grid disturbance when this was not evident from the LER. The NERC DAWG analyzes a subset of the grid events reported to the Department of Energy (DOE) under 10 CFR, Chapter II, “Report of Major Electric Utility System Emergencies,” Section 205.351 “Reporting Requirements,”(Ref. 18). Section 205.351 requires electric utilities or other entities engaged in the generation, transmission, or distribution of electric energy for delivery or sale to the public to report to DOE certain losses of system “firm” loads, voltage reductions or public appeals, vulnerabilities that could impact system reliability, and fuel supply limitations. Some of the DOE events that involve the transmission system are of interest for this report. The DOE events and NERC DAWG reports are available on their websites.

In many of the Appendix A events power restoration, which is important from a risk perspective, was at least in part, dependent on grid operator direction and action following grid initiated event. The Appendix A events were defined and grouped as follows:

- R events are losses of electric power from any remaining power supplies as a result of, or coincident with, a reactor trip at power. R events are random tests of the capacity and capability of the grid. Losses of electric power with a reactor trip include any LOOPs, partial LOOPs, momentary LOOPs, or voltage degradations below the plant specific low limit. The LOOPs are potentially risk significant.

- S events are reactor trips where the first event in the sequence of events leading to the reactor trip was in the switchyard or substation nearest the plant.

- T events are reactor trips where the first event in the sequence of events leading to the reactor trip was in the transmission system beyond the switchyard or substation nearest the plant.

- L events are LOOPs where the first event in the sequence of events leading to the LOOP was in the grid. LOOPs at zero power are indicated by a zero suffix. Momentary LOOPS are indicated by LM. LOOPs at power are potentially risk significant.

- PL events are partial LOOPS where the first event in the sequence of events leading to the partial LOOP was in the grid.

- I events are events of interest that provide insights into the plant response to a grid initiated event, but did not involve a unit trip, LOOP, or partial LOOP.

Table 1 “Grid Event Summary,” gives the numbers, types, and dominant causes the reactor events from 1994 to 2001 based on detailed information in Appendix A, Tables A-1 and A-4. The R and L event groups LOOPs are potentially risk significant and analyzed in Section 3.2 and discussed in Section 3.3.

Table 1 – Grid Event Summary

Event group		Number of reactor events per year (1994–2001)									Dominant causes
		94	95	96	97	98	99	00	01	Total	
R		0	0	2	3	1	3	1		10	3 LOOPs , 6 partial LOOPs, & one voltage degradation from plant/grid electrical weaknesses
S		4	6	2	2	2	2	4	2	24	Grid equipment malfunctions
T		4	5	7	3			2	1	22	Grid equipment malfunctions
L	@ power					1				1	Grid equipment malfunctions
	0 power	1			1		1	1		4	Human error
PL		3			1	2	1	2		9	Grid equipment malfunctions
Total		12	11	11	10	6	7	10	3	70	Grid equipment malfunctions

Simplified event trees were developed in Appendix B, “Risk Analyses” for the purposes of estimating and comparing the average industry CDF from an SBO before (1985–1996) and after (1997-2001) from deregulation using LOOP and other operating data in Appendix C, “LOOP and Scram Data 1985-2001.” As mentioned above, past risk analysis typically consider a reactor trip followed by a LOOP, to be two independent events, i.e. risk analysis do not always model this event because of low probability. However, Table 1 there were more LOOPs from R events - as a result of or consequence of a reactor trip - than L events. Appendix C, “LOOP and Scram Data 1985–2001,” Table C-1 shows that two of the six LOOPs between 1997-2001 were as a consequence of a reactor trip was developed; based on this observation, a model was developed below to evaluate the risk contribution from a LOOP as a consequence of a reactor trip. As all of the LOOPs since 1997 occurred in the summer-May to September in contrast to 23 of 54 LOOPs in the summers of 1985-1996, the data was also analyzed after deregulation for the summer months.

3.2 Risk Insights and General Observations

3.2.1 Risk Insights

The risk results are summarized in Table 2, “Changes In Risk After Deregulation.” The table provides a “delta CDF” and “observations” that help explain the delta CDF in term of key data changes.

The “delta CDF” was obtained by subtracting the risk “BEFORE” deregulation from the risks after deregulation. A negative delta CDF indicates the risks have decreased since deregulation. A positive delta CDFs may offset the risk reduction obtained from SBO rule implementation. Specifically a delta CDF of more than 0.6E-05/RY (the difference between the risk reduction outcome and expectation from SBO rule implementation) and a delta CDF of more than 3.2E-05/RY (the outcome from SBO rule implementation) partially and completely offsets the risk reduction from SBO rule implementation, respectively.

Table 2

Changes In Risk After Deregulation

Observation		**Baseline Change -Delta CDF/RY**
BEFORE deregulation 1985–1996	Average industry CDF from an SBO is 1.3E-05/RY considering consequential and plant/grid/weather LOOPs . -Risk reduction from SBO rule 3.2E-05/RY; expectation 2.6E-05/RY -Reactor trips/RY=3.4 -LOOPs/RY=0.05 -Probability(LOOP/reactor trip) =0.002 -Percent LOOPs >4hours=17%	0
AFTER deregulation 1997–2001	Risk reduction from SBO rule implementation maintained. CDF decreased below baseline due to offsetting changes: -Reactor trips/RY =1.0 -LOOPs/RY=0.009 -Probability(LOOP/reactor trip)=0.0045 -Percent of LOOPs > 4 hours=67%	-0.9E-05
SUMMER After deregulation 1997-2001	Risk reduction from SBO rule implementation maintained. CDF decreased below baseline due to offsetting changes: -Reactor trips/RY=1.1 -LOOPs/RY =0.021 -P(LOOP/reactor trip)= 0.01 -Percent LOOPs > 4 hours =67%	-.5E-05
SUMMER SENSITIVITY 1997-2001	Risk reduction from SBO rule implementation offset -EDG out-of-service for 14 days with a chance of a degraded grid -Increase time grid degraded to 30 days based on experience -EDG out-of-service for 14 days with the grid degraded	 1.1E-05 1.4E-05 7.8E-04

The BEFORE observations benchmark the risks, the risk reduction obtained from SBO rule implementation which are used to evaluate the significance of changes in risk after deregulation, and key data that are used to explain the delta CDF. The key data include the number of reactor trips per RY; the number of LOOPs/RY; the probability of a LOOP as a consequence of a reactor trip or and the percent LOOPs more than 4 hours. As a point of reference P(LOOP/RT) is 0.002 and corresponds to the grid being in this condition approximately 18 hours per year (8760 hours per year times 0.002). The results are compared graphically in Figure 1, “Risk Profile” in terms of the CDF/RY. Figure 1 and Table 2 indicate the following:

- The risks “AFTER” deregulation (1997-2001) have decreased just below the risk BEFORE deregulation. This indicates that deregulation has not eroded the risk reduction from SBO rule implementation. Comparison of the key factors in Table 2 before and after deregulation help to explain the decrease in the risk; i.e., the decreases in the risk from the decreases in the number reactor trips/RY and number of LOOPs/RY have offset the increases in the risk from the increases in percentage of LOOPs more than 4 hours and probability of a LOOP given a reactor trip. As a point of reference P(LOOP/RT) is 0.0045 (as compared to 0.002 before deregulation) and corresponds to the grid being in this condition approximately 40 hours per year.

- The risks after deregulation in the “SUMMER” - May to September, 1997–2001- have decreased slightly below that BEFORE deregulation; again deregulation has not eroded the risk reduction from SBO rule implementation. Comparison of the key factors in Table 2 before and after deregulation help to explain the decrease in the risk; i.e. the decreases in the risk from the decreases in the number reactor trips/RY and number of LOOPs/RY have offset the increases in the risk from the increases in the percentage of LOOPs more than 4 hours and the probability of a LOOP given a reactor trip. As a point of reference P(LOOP/RT) is 0.01 and corresponds to the grid being in this condition approximately 88 hours per year, all during the summer months.

- SUMMER SENSITIVITY studies were completed to evaluate the potential risk increases from (1) the EDG out of service (OOS) for 14 days with a higher likelihood that the grid will be in degraded condition, (2) increasing in the amount of time that the grid is degraded, and (3) the EDG OOS for 14 days while the grid is degraded. Actual approved EDG OOS typically range from 3 to 14 days; plant specific analyses may provide different results.”

  Table 2 delta CDFs indicates that in each of these three case, the risk increase partially or fully offsets the risk reduction from SBO rule implementation. In each of these cases, this risk increase may not be detected unless the assessment of the risk considers the increased CDF from an SBO (a) as a result of a consequential LOOP and other LOOPs separately (b) summer time operation (c) actual demand performance under LOOP conditions (d) the results of electrical analyses to determine whether a reactor trip will cause a LOOP (discussed in Section 3.3). The discussion follows:

(1) The first sensitivity study estimated a delta CDF as a result of having one of two EDGS OOS with a 0.01 chance that a LOOP will result from a reactor trip. Table 2 and Figure 1 shows this as a spike in the risk as “EDG/Avg” that is just above the risk before deregulation

(2) The second sensitivity study evaluated the risk increase from an increase in the amount of time the grid was degraded (the time that the probability of a LOOP given a reactor trip was 1) to approximately 800 hours or approximately 30 days . When this time is increased to 800 hours, the risk and delta CDF increase above the BEFORE values as shown in Figure 1, “30Day” and Table 2. At a recent meeting, EPRI shared data that showed that one region of the country experienced a “Stage 3" alert approximately 795.8 hours over a few months in one year as a result of market gaming. Stage 3 is when the system reserves have been depleted to approximately 1.5% of the load and the final stage of the grid operators three-step emergency program that is accompanied by load curtailment (rolling blackouts) to keep from further erosion of the reserves needed for system stability should there be a disturbance such as a large generating unit trip or transmission system fault.

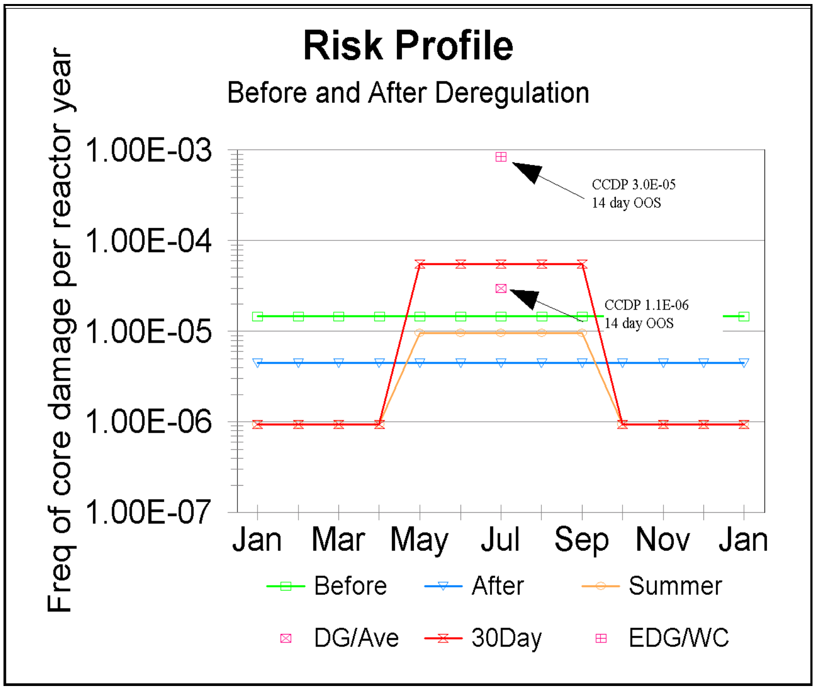

Figure 1 - Risk Profile

(3) As shown in Figure 1 and Table 2, the worse case increase in the risk above the before deregulation values is when the one EDGs is unavailable for 14 days with the reactor at power and the grid is in a condition such that a LOOP could result from a reactor trip. Figure 1 shows this as a spike, “EDG/WC.” As previously discussed, TS typically allow one EDG to be unavailable for allowed outage times (AOTs) of up to 72 hours, and in some cases with compensatory measures, up to 14 days. “As previously discussed in Appendix B, Section B.4, item (4) the CCDPs used in the risk analysis reflect the use of compensatory measures.

The NRC does not regulate the grid; however, the performance of offsite power is a major factor for assessment of risk. As previously discussed the licensees are expected to assess and manage the increase in the risk that may result from maintenance and outage activities; NPPs should understand the condition of the grid before scheduling EDG, maintenance or AOTs.

Assessment

With respect to maintaining the current levels of safety, offsite power is especially important with regard to the risk associated with emergency diesel generator (EDG) maintenance and outage activities. Consequently, NRC and licensee assessments of risk that support EDG maintenance and outage activities should include: (a) assessment of offsite power system reliability, (b) the potential for a consequential LOOP given a reactor trip, and (c) the potential increase in the LOOP frequency in the summer (May to September). Regarding (a) above, the assessment of the power system reliability and risks from plant activities can be better managed though coordination of EDG tests with transmission system operating conditions.

3.2.2 General Observations

1. Table 1 shows that grid problems that affect the NPP are not infrequent. Table 1 shows that grid equipment failures and malfunctions were the dominant causal factor for every event group except the R event group, which was dominated by grid and plant electrical weaknesses (see Section 3.3.2). Appendix A indicates that most of the grid equipment failures and malfunctions were in high-voltage circuit breakers and protective relays of the switchyard and transmission system.

2. Some NPPs and transmission companies used the experience (events 1, 2, 37 in Appendix A) to establish or strengthen interface agreements to better control operating, maintenance, and design activities that potentially affect the NPP. Similar agreements could be used to enhance the maintenance of high-voltage circuit breaker and protective relays which were previously noted to be a dominant causal factor. The NRC does not require or review these agreements.

   In event 2, the SBO alternate ac power supply failed to start during a NPP test and the NPP discovered that the transmission company, who owned the alternate ac (SBO) power supply, installed a modification 4 months earlier that defeated its safety function. This is an example where a contractual agreement requiring NPP review and approval of transmission company SBO alternate ac power supply modifications may have ensured their operability.

3. While the data set is small, recent experience indicates that the average duration of LOOPs has increased. Based on historical data, power restoration times following a LOOP are assumed to be less than 4 hours; most recent LOOPs have lasted significantly longer. In addition, longer LOOPs are not consistent with regulatory expectations . Table 3, “Percent of LOOPs Greater Than 4 Hours,” shows changes in the percent of LOOPs more than four hours and median recovery times.

Table 3
LOOP Recovery Time

	Before SBO rule NUREG-1032 1968-1985	Before Deregulation BASELINE 1985-1996	After deregulation AFTER 1997-2001
Percent of LOOP > 4 hours	7	17	67
Median LOOP restoration time in minutes	36	60	612

NUREG-1032 concludes that “the capability to restore offsite power in a timely manner can have a significant effect on accident consequences.” NUREG-1032 found the overall median recovery time to be 36 minutes based on data from 1968 through 1985. NUREG-1032 data shows seven percent were more than four hours; one was a grid event, three were weather related events, and the longest plant related event was 165 minutes. NUREG-1032 expected “enhanced recovery times” for grid related and severe weather LOOPs based on the availability of plant recovery procedures and at least one source of ac power. NUREG-5496 data from 1985–1996 indicates the overall median recovery time for LOOPs at power to be 60 minutes and that 17 percent of the LOOPs lasted more than 4 hours. More recently, the data from 1997-2001 show 67 percent of the six LOOPs lasted more than four hours and the median recovery time is 612 minutes. Appendix C data shows that one plant LOOP was 1980 minutes, two weather (involving the grid) LOOPs lasted 688 and 1560 minutes, and one LOOP from a reactor trip lasted 612 minutes (event 16). The expectations for enhanced recovery have not been achieved. In addition, five of the six LOOPs since 1997 involved the grid.

4. Three of the events summarized in Appendix A reached thresholds of interest from a risk perspective under the NRC ASP Program. The ASP Program found the CCDPs of events 16, 33, and 58 to be 2.8E-06, 9.6E-06, and 9.1E-05, respectively. The CCDPs reached a threshold interest because of NPP conditions, not because of grid anomalies. However the ASP analyses of individual events alone may not be giving the entire picture from a risk perspective. For example as shown in Figures 1, the CCDP is a factor in the analysis of the CDF and CCDPs on the order of E-06 and 3.0E-05 can result in CDFs that could substantially offset the reduction obtained from SBO rule implementation.

5. Events identified equipment sensitivities to low voltage.

   Three events in Appendix A (8, 20, 34) identified microprocessor-controlled equipment that was sensitive to low voltage as follows: a radiation monitor lost program memory (event 8); several programmable controllers swapped from auto to manual following a voltage transient (event 20); and voltage-regulating transformers shut down following a voltage transient, and the licensee found they automatically shut down when voltage drops to 20% of nominal for 6 to 8 cycles (event 34). Microprocessor-controlled equipment has been used to replace analog equipment, and the voltage characteristics of the replacement equipment appears to warrant attention.

Two events in Appendix A (17 and 45) show that circulating water pump synchronous motor trips are sensitive to momentary low voltages due to switchyard and transmission line faults. Optimizing synchronous motor protective trips may avoid some reactor trips.

Assessment

It is important to have mechanisms in place to ensure that grid operators will provide reliable electrical power. Since external factors impact the ability of licensees to manage risks and understand the condition of the grid, some NPP licensees have implemented contractual agreements with grid operators to provide a mechanism for maintaining secure electrical power in the deregulated environment. Contractual arrangements should include specific, communication protocols, operating procedures and action limits, maintenance responsibilities, SBO (alternate ac) power supply responsibilities, and NPP and grid.

While the data set is small, recent experience indicates that the average duration of LOOPs has increased. Based on historical information, power restoration times following a LOOP are assumed to be less than 4 hours; more recent LOOPs have lasted significantly longer. Recently (1997-2001) NPP and grid operating experience power restoration times are typically in excess of four hours and in the past they were rarely longer than four hours. Longer restoration for most of the events challenge whether either the NPP or the grid operator could actually restore power to a NPP in time under accident conditions such as an SBO. These events support the concern identified in SECY 99-129 that the time needed to coordinate grid operations may increase in a deregulated environment.

3.3 Nuclear Plant Voltages Not Always Analyzed For Grid Conditions Experienced

The review of the R events in Appendix A found that three LOOPs (events 3, 16, and 33), five partial LOOPs (events 15, 22, 38, 60, 62, and 64) and a voltage degradation below the minimum voltage required by the technical specification for 12 hours (event 74) occurred coincident with, or as a result of, a reactor trip. These events were similar as follows:

(1) Up to the time of the reactor trip, the offsite power supplies were operable per NPP control room voltage readings that verified the technical specification minimum voltage requirements. In addition, analyses of the offsite power system following a unit trip did not predict these events.

(2) A review of the previous and subsequent reactor trips at the NPPs with R events in Appendix A found that LOOPs, partial LOOPs, and voltage degradations were not coincident with these reactor trips. The initial grid and plant electrical conditions at the time of the R events were different than in previous and subsequent reactor trips and did not include heavy transmission line loading, switchyard and transmission EOOS, and degraded plant voltage-controlling equipment. This is discussed further in Section 3.3.1.

(3) Eight of the 10 R events took place in June, July, and August. Seven of the 10 events were in the Northeast (Maryland, New York, New Jersey, Pennsylvania, and Vermont). In the summer, the increased system loading associated with the temperature lowers the voltage at the ends of transmission lines. This is discussed further in Section 3.3.2.

(4) The partial LOOPs (events 15, 22, 38, 60, 62, and 64) and a voltage degradation below the minimum voltage required by the technical specification for 12 hours (event 74) are not risk significant but provide early indication that NPPs may not have analyzed the grid for the conditions experience.

3.3.1 Grid Loading and Equipment Out of Service

Ideally, NPPs determine NPP voltage limits based on electrical system analyses which account for the most limiting transmission system loading conditions and equipment out of service (EOOS).

In event 74 in Appendix A, the licensee found that their failure to properly consider the impacts of deregulation (i.e heavy grid loading coupled with the loss of voltage support from the NPP generator) resulted in lower than expected NPP safety bus voltage. In addition it took 12 hours to change power flows between Canada and Texas and get the required voltages to the NPP; this helps to confirm the SECY 99-129 hypothesis that changes in ownership and control of generation and transmission facilities adds to the number of entities that must be coordinated and is likely to increase recovery times following a grid disturbance. Coordination of grid operators in a deregulated environment challenges the expectations of “enhanced recovery” or power recovery to the grid accident conditions. In event 3 the licensee attributed the LOOP to the combined effects of heavy grid loading, a 500 kV substation out of service (OOS), loss of voltage support from the NPP generator (resulting in a 4.5% voltage drop) and the transfer of the NPP load (which resulted in an additional 3 to 6% voltage drop). The severity of the grid condition revealed that the NPP station power transformer automatic tap changer had not been set consistent with the design analyses so it could not compensate for the degraded grid.

Transmission analyses typically assume at least one major pre-event EOOS or contingency. Events 15, 33, 38, and 60 in Appendix A involved multiple contingencies or very abnormal operating conditions. Event 15 involved a transmission line outage and a substation outage that left one of two available power generation paths, and a transmission line OOS that disabled a NPP protective trip. In event 33, the licensee attempted sustaining NPP operation with major current unbalances in both high-voltage generator output circuit breakers. In event 38, a switchyard high-voltage circuit breaker was inadvertently closed during troubleshooting with one of three offsite transmission lines OOS and a latent failure in a high-voltage circuit breaker control system. In event 60, one of two high-voltage generator circuit breakers was OOS, a latent failure existed on a switchyard disconnect switch, and NPP electrical equipment malfunctioned.

In some events plant equipment, such as station power transformer automatic tap changers, which control safety bus voltage levels, is assumed to be functional in the analyses of internal voltages and by the grid controlling entity for the range of external voltages maintained at the NPP. Thus, an inoperable NPP transformer automatic tap changer is a problem for both the NPP plant and the grid operators As mentioned earlier in event 15 in Appendix A, a NPP transformer automatic tap changer had not been set consistent with the design analyses. In event 16 in Appendix A, a NPP transformer automatic tap changer had been in manual for approximately 1 year due to a degraded relay and procedures that allowed its manual operation without compensatory measures. Alarms that would draw operator's attention to inoperable safety bus voltage controlling equipment can help NPP operators identify the need to request additional voltage support from the grid operators. Periodic verification of NPP transformer automatic tap changer or other voltage controlling equipment operability could also help reduce the likelihood and impact of low voltage damage to plant equipment. In addition, NPP procedures that allow manual operation of this equipment should require compensatory measures such as a request for voltage adjustment from the grid control entity prior to operation.

Four events in Appendix A were also random tests of the grid that resulted in unexpected voltage drops; these types of events may provide early signs of weaknesses in offsite power system capacity and capability. In event 22, the offsite power system could not support the simultaneous restart of two 5500 HP feedwater pump motors without a partial LOOP. In event 59 the restart of a reactor recirculation pump motor caused an unexpected voltage transient. In event 57 the electrical perturbation from Unit 1 reactor trip, tripped a Unit 2 heater drain pump motor and caused a Unit 2 load reduction. In event 67 seven safety and some nonsafety motors tripped, and did not restart following the voltage drop from the bus transfer and start of two auxiliary feedwater pump motors. In events 22 and 67 if the grid does not have the capability, automatic control circuitry could be used to minimize the probability of a LOOP.

3.3.2 Grid Reactive Capability Weakened

Several of the R events occurred in the summer in the Northeast. The PJM Interconnection issued a publicly available study, "Results of Heat Wave 1999: July 1999 Low Voltage Condition Root Cause Analysis," dated March 21, 2000 (Ref. 19) for the purposes of identifying and correcting the root causes of low-voltage conditions on two exceptionally hot days on July 6 and 19, 1999. On both occasions the 500 kV system voltage at multiple sites dropped approximately 5% from highs ranging from 545 kV to 525 kV, to lows ranging from 515 kV to 495 kV. Short-term (30 minutes) grid anomalies during periods of high load are not uncommon while the grid operating entity determines and completes response actions. PJM was concerned that the peak load was not predicted and noted that it took several hours to restore voltage after implementing all load management programs and 5% voltage reductions. The PJM concerns are consistent with those in SECY 99-129, IN-98-07, and IN-00-06.

The PJM data show that, in both cases, widespread voltage reductions began near 10am and voltages dropped sharply at noon. The voltages were restored to the 10am and noon levels in approximately 10 and 6 hours, respectively, on July 6 and in 7 and 2 hours on July 19.

PJM found that the low-voltage conditions occurred because reactive demand exceeded reactive supply due to record usage of electricity from high temperatures in much of the eastern half of the U.S. Reactive supply was insufficient because some generators were unavailable or unable to meet their rated reactive capability due to ambient conditions. Specifically, 54 PJM generators reached a limit that restricted MVAR output to 72% of the reported capability and weakened the grids capability to maintain adequate levels of voltage.

The PJM system did not have the reactive capacity as required by GDC 17 and consequently was unable to restore voltages as quickly as expected. The analyses of grid voltage levels were incorrect because generator reactive capability design limits were used instead of the actual capabilities. Consequently, NPP voltages used to determine operability and analyses of offsite voltage performance after a reactor trip are likely to be optimistic. Alternatively compensating reactive capability can be purchased, obtained from new reactive power sources such as new generation or capacitor banks.

As another consideration, reactor power uprates also reduce generator reactive capability and collectively weaken the grid's capacity to maintain or restore voltages as it did on the PJM system. Licensees have been using power uprates to increase the output of their NPPs. As of May 1, 2002, the NRC has completed 62 reviews, and the industry has collectively gained approximately 3760 megawatt thermal (MWt) or 1200 megawatts electrical (MWe), an average of approximately 20 MWe increase per NPP. However, the main generator reactive capability decreases as the power (MW) output increases. For example, if a generator had a nameplate rating of 1000 MVA, 95% power factor at rated voltage, it would correspond to an operating point of 950 MW and 312 MVAR. If the power output increased approximately 20 MW to 970 MW, the reactive capability would decrease to 243 MVAR, a difference of approximately 70 MVAR. Collectively, the 1200 MW increase on 62 reactors has been accompanied by a 4340 MVAR decrease.

Assessment

An important aspect of the changes to the electrical grid is the impact on the electrical analyses of NPP voltage limits and predictions of voltages following a reactor trip and whether a reactor trip will result in a LOOP. Recent experience shows that actual grid parameters may be worse than those assumed in electrical analyses due to transmission system loading, equipment out-of-service, lower than expected grid reactive capabilities, and lower grid operating voltage limits and action levels. NPP design basis electrical analyses used to determine plant voltages should use electrical parameters based on realistic estimates of the impact of those conditions.

Lessons learned include:

- LOOPs, partial LOOPs, momentary LOOPs, and voltage degradations below the technical specification low limit following or coincident with a reactor trip are evidence of a potential electrical weaknesses in the grid.

- The synergistic effects of reduced reactive capability on the NPP from hot weather and several reactor power uprates should evaluated.

- In some events, plant equipment such as station power transformer automatic tap changers, which control safety bus voltage levels, is assumed to be functional in the analyses of internal voltages and by the grid controlling entity for the range of external voltages maintained at the NPP. Periodic verification of NPP or other voltage controlling equipment operability may be necessary to ensure their availability and require compensatory measures such as a request for voltage adjustment from the grid control entity should availability be compromised.

- Under some circumstance degraded grid recovery times may take several hours. In the Northeast, it took the grid operator for 12 NPPs 10 hours to resolve grid problems from the unexpected behavior of the grid after planned voltage and load management programs had been implemented and investigation found the grid power restoration procedures did not work because the grid did not have the reactive capacity to quickly restore voltages. In the Mid-West it took grid operations 12 hours to change regional power flows and restore voltage to a NPP after the grid was stressed. These events support the concern identified in SECY 99-129 (as discussed in the background section) that the time needed to coordinate grid operations may increase in a deregulated environment.

3.3.3 Transmission System Faults May Involve Multiple Reactor Trips

The review of the T events found that transmission system faults may involve multiple reactor trips (events 24, 25, 48, and 53 in Appendix A). None of the events caused a LOOP. Events 48 and 53 were similar: two reactors at a dual-unit site tripped after a remote transmission line fault opened multiple high-voltage circuit breakers, including the generator output breakers in the switchyard.

In events 24 and 25, multiple reactors tripped, and other NPP operations were affected in a minor way, during a grid disturbance due to the operation of common protective and/or design features. The licensee final safety analysis reports (FSARs) demonstrated the adequacy of the offsite power system by summarizing the results from power system analyses without discussing operation of these features. In event 24, two pressurized water reactors (PWRs) tripped simultaneously due to reactor coolant pump (RCP) bus undervoltage during a transmission system disturbance. As a corrective action, one of the NPPs lowered the RCP bus undervoltage and underfrequency setpoints to the minimum allowed by the technical specifications. In event 25, four PWRs tripped simultaneously: at one site, two reactors tripped due to RCP bus undervoltage; and at another site, two of three reactors exceeded the variable overpower trip setpoint (VOPT) during the load swing at the NPP from the transmission system fault.

Differences in the moderator temperature coefficient (MTC) levels explain why two of three reactors tripped at one site. The MTC is a measure of the reduction in the core reactivity as the water temperature increases. Two of the three reactors tripped when load fluctuations (a 700 MW decrease and significant load increase due to the grid instability) caused the steam bypass control system (SBCS) valves to open and exceed the VOPT setpoint within the core protection calculators (CSCs). The third reactor spiked to 102% power without reaching the VOPT setpoint. The MTCs for the two reactors that tripped were -34 and -23.5 pcm per degree Fahrenheit and near the end of core condition (EOC). The MTC for the reactor that did not trip was more positive (-9 pcm per degree Fahrenheit) and near the beginning of core conditions. The CPC VOPT is an expected response to the load change, as are the opening of the SBCS valves, the increased steam demand, and the resulting power increase due to decreasing temperature with a negative MTC. However, the closer the unit is to the EOC, the more rapid the power increase and more likely that VOPT will trip the reactor.

The risk significance is that in the cases above the total risk from an event would be equal to the sum of the risks from individual plants affected. The risk from a transmission line fault is the sum of the risks from the NPPs involved i.e. 2–4 times individual plant risks.

As summarized in Appendix A, industry analyses of events 24 and 25 resulted in a total of 65 recommendations to address improved regional operational and engineering activities to maintain grid reliability. The events resulted in recommendations that helped CAISO, which was under development at the time of these events, to develop and implement a very broad and comprehensive grid reliability program to manage and control regional operational and engineering activities in real time. The program includes continuous update of analyses to reflect operating conditions and changes in operating configurations .

Assessment

The significance of a grid event will need to take into consideration the impact of multiple reactor units. In addition, NPP licensee analysis of the affects of transmission system disturbances had not been updated to account for current grid conditions. Operation in a deregulated environment may be better served by a comprehensive grid reliability program to manage and control regional operational and engineering activities in real time, as is the case with the California ISO and PJM, to maintain secure electrical power to NPPs.

3.4 NPPs Must Contract For Adequate Voltage Support

As a result of the July 1999 events, PJM identified 20 corrective actions including one in the area of voltage operating criteria. The PJM website provides the “Voltage Criteria and Voltage Limits Working Group Report,” dated September 11, 2000 (Ref. 20) that contains the “PJM-Base-Line Voltage Limits,” which are duplicated below in Table 4. These voltage limits were part of FERC Docket No. ER00-2993-000, “Order Accepting Tariff Filing,” dated August 31, 2000, which amends the PJM Operating Agreement to permit and accommodate requests that PJM schedule and dispatch generation to meet voltage limits (in Table 4) that are more restrictive than those PJM otherwise determines are required for the reliable operation of the transmission system in the PJM control area.

Table 4. PJM Base-Line Voltage Limits

Voltage level (kV)	**Load Dump* (kV)**	**Emergency Low** (kV)**	**Normal Low (kV)**	**Normal High (kV)**	**Voltage Drop****
500	475 0.95	485 0.97	500 1.00	550 1.10	5%
345	310 0.90	317 0.92	328 0.95	362 1.05	5-8%
230	207 0.90	212 0.92	219 0.95	242 1.05	5-8%
138	124 0.90	212 0.92	131 0.95	145 1.05	5-10%
115	103 0.90	106 0.92	109 0.95	121 1.05	5-10%
69	62 0.90	63.5 0.92	65.5 0.95	72.5 1.05	5-10%

***=post-contingency 5 minute Emergency Limit, **=post-contingency 15 minute Emergency Limit**

Table 4 “ “Normal” voltages of 0.95 nominal are likely to be below plant specified limits. NPPs will have to request more restrictive voltage limits per the tariff. The entity making the request will be responsible for all incremental generation and other costs, and that PJM will post on its internet site its current determination of the voltage criteria that it will employ for transmission grid reliability. In its filing, PJM used NPP voltage requirements to demonstrate the need for the amendment to the operating agreement, stating that NPPs may have internal plant requirements that require voltage limits different than the generic voltage limits necessary for the transmission system.

RES previously found (ref 10) that on the west coast the CAISO and its NPP generators have implemented binding "transmission control agreements" to ensure, in part, that the appropriate technical parameters in the NPP analyses are explicitly stated. In a meeting between the NRC and the industry on May 18, 2000 (ref. 13) one of the west coast NPPs discussed the status of a NPP "grid specification" for the grid operator. The specification gives technical details that the grid operators need, such as NPP transient and steady state loads, as a function of time, to ensure the 230 kV offsite power system voltage would not go below the 218 kV. The grid specification requires inspection and preventive maintenance of 230 kV switchyard equipment under the control of the transmission entity but important to the adequacy of the NPP offsite power system.

Assessment

Some grid operating entities that supply offsite power to NPPs, such as PJM and the CAISO, maintain comprehensive grid reliability programs. They manage and control regional operational and engineering activities through activities such as: electrical analysis of the grid in real time, development of time-based voltage criteria, and implementation of binding contracts to supply electrical power to meet NPP specifications. These programs help NPPs maintain the validity of technical specifications, recovery times consistent with the SBO rule, and their obligations under GDC17. These programs have been, in part, implemented through contractual agreements between NPPs and grid operators so as to provide a mechanism for maintaining some assurance of secure electrical power in a deregulated system to include specific grid and NPP electrical requirements necessary to analyze and monitor the grid for the NPP.

3.5 EDG Test With Grid Degraded May Compromise Independence

Operating experience (events 7, 24, and 56) shows that an EDG failed one of three times while running to the grid for test given a grid transient such as one in the transmission system or from reactor trip. From a risk perspective, EDG testing to the grid for up to 24 hours was found to be important, but not as significant EDG AOTs of 14 days with the grid degraded previously discussed in Section 3.2. In event 7, the EDG tripped as transmission system switching operations were being performed. In event 24, the EDG was exposed to a transmission system fault while protective relaying was out of service to allow transmission test activities. In events 7 and 24, the EDG tripped and realigned to the safety buses as designed. However, in event 24 the EDG tripped later in the event when attempting to restore offsite power. Better coordination of EDG test and transmission test and operating activities might have minimized the risks.

In event 56, the EDG overloaded after attempting to assume a greater share of the load on the grid when the reactor tripped. The licensee estimated that the EDG current exceeded 600 amps for 5 minutes (at least 133% above its continuous rating and 113 % above its short-time rating) which was just below its overcurrent trip. No EDG damage was found during follow-up inspection and tests. It could be argued that there EDG could have been restarted immediately if required. It could also be argued that the EDGs may not have the thermal capability to restart immediately successfully for this event, i.e. the EDGs were not typically purchased, or tested, to demonstrate they have the thermal capability to withstand an initial load sequence, load run, an overload as described, and immediately begin load sequencing for a second time. Better protective relaying would trip the EDG from an overcurrent within a few seconds of the reactor trip.

<u>Assessment</u>

Experience shows that running the onsite emergency diesel generator (EDG) to the grid for testing with the reactor at power can potentially result in (a) the loss of an offsite and onsite emergency power supply, or (b) damage to the EDG. The potential for these incidents could be reduced if the NPP and the transmission company would better coordinate activities so that the EDG is not tested to the grid when the grid is in a degraded condition.

3.6 Potential Damaging Effects of Current Unbalances From Grid Disturbances

An RES report "Operating Experience Assessment-Energetic Faults in 4.16 kV To 13.8 kV Switchgear and Bus Ducts That Caused fires In Nuclear Power Plants 1986-2001," dated February 22, 2002 (Ref. 21) discussed an event that occurred on March 18, 2001, at a nuclear plant in Taiwan, involving a fire and SBO due to an energetic electrical fault in 4.16 kV switchgear with an insulation failure. The CCDP for the event was 2.2E-03. The damage was so extensive that the exact cause could not be determined. A University of Texas consultant reviewed the NPP station logs and found that frequent unbalanced transmission line voltages since 1985 may have resulted in current unbalances (also termed negative phase sequence current) that e prematurely aged the switchgear insulation. The utility suspected that ferromagnetic resonance–NPP plant and transmission system equipment electrical interactions–may have resulted in damaging levels of voltage. The available information indicated there was no safety bus protective relaying to quickly detect the conditions.

In events 33, 50, 75, and 78 in Appendix A, phase current unbalances from grid-initiated events tripped the reactor. In three of the four events (50, 75, 78), reactor trips were initiated as a result of current unbalances from grid events that tripped non-safety-related RCP motors, circulating water pump motors, or the main generators. In these events, alarms also alerted operators to abnormal current unbalances.

Event 33 shows the damaging effects of phase current unbalance on NPP switchyard equipment. In June 1997 a switchyard relay technician reported unbalanced phase current readings on phase B of the generator 230 kV output circuit breakers GB1-02 and GB1-12. The readings for GB1-02 were 1020, 420, and 1080 amps; normally these readings are within a few percent of each other but these readings indicate a 60% current unbalance. The current readings for GB1-12 were 1182, 2100, and 1140 amps and indicate an 80% current unbalance. The plant operated at 100% power for two days when the GB1-02 circuit breaker failed and the generator and reactor tripped.

Assessment

Experience indicated that transmission system operation or disturbances may cause sustained or frequent current unbalances that result in damage to electrical equipment. It is common practice to protect expensive or important nonsafety equipment from current unbalances. Safety equipment does not always have the same level of protection. RES will further analyze this issue in the future.

3.7 Grid Transients May Degrade Scram and ATWS Capabilities

Grid-induced reactor transients can affect scram capability . Events 64 and 65 in appendix A show that the BWR reactor scram or the end-of-cycle reactor recirculation (EOC-RPT) pump trip may not occur during large load swings (approximately 800 MW) from a grid disturbance. In events 64 and 65, faults and equipment problems at an offsite 500 kV switchyard that directly feeds an NPP 500 kV switchyard resulted in generator load fluctuations, fast closure of the turbine control valves (TCV), and a reactor trip without the EOC-RPT. The licensee's evaluation of the events found that a partial load rejection can actuate circuitry that causes TCV motion in excess of design assumptions and may not always actuate a reactor scram or satisfy the EOC-RPT control logic. The licensee found the FSAR analyses enveloped these events. Although not required, the licensee did not investigate if large load fluctuations produce pressure excursions that approach those analyzed for an ATWS.

Assessment

Operating experience identified an instance where ATWS mitigation based on EOC-RPT logic failed to operate correctly during a transmission system fault that produced large electrical load fluctuations. However, the risk associated with this failure is expected to be very low.

3.8 Effects of Overfrequency On Reactor Integrity

Grid-induced reactor transients can affect reactor vessel integrity. The Westinghouse evaluation of event 15 in Appendix A found that "gross tilting" or rocking of the reactor internals (i.e. uplift of the fuel rods due to excess RCP flow) is limiting with respect to allowable reactor coolant flow. While the licensee was taking one of two available 345 kV power generation paths for a NPP OOS, a 345 kV relay malfunctioned, tripped the remaining power path, and tripped the reactor following a load rejection. The EOOS also disabled an NPP electrical protective trip that left the RCP electrically connected to the main generator, which was overspeeding from the load rejection. The RCP rated flows increased from 96% to 111.8% as a result of the increased frequency from the main generator. In analyzing the effects of the increased RCP flow, Westinghouse found a new RCP flow limit of 115.8% is more limiting than the previous 125% limit identified in the licensee's FSAR. Had the RCP flow been at 100% initially, the new limit may have been reached.

Assessment

Grid conditions which result in over-frequency conditions can have unexpected consequences. At one plant, over-frequency conditions following a load rejection caused speed-up of the reactor coolant pumps which generated lifting forces on the core to within a small margin of causing core mechanical tilt. The over-frequency condition was not properly accounted for by the plant protective relay control logic.

4 ASSESSMENT

Deregulation of the electrical industry has resulted in major changes to the structure of the industry over the past few years. Whereas before, a single unified corporation both produced the electricity and operated the distribution system, that is no longer the case. The industry has split into separate generating companies and transmission companies. Increased coordination times to operate the grid may result from involvement of more companies. In addition, generating companies have daily open access to the grid and this changes the grid design and operating configurations that were established before deregulation. NPPs rely on an outside entity to provide reliable electrical power for NPP operation. RES completed an assessment that is intended to identify changes to grid performance relative to the safety performance of NPPs. The assessment also provides some numerical measures to characterize grid performance before and after deregulation - in particular, those related to a LOOP.

The information gathered provides a baseline of grid performance to gauge the impact of deregulation and changes in grid operation. The period 1985–1996 was considered "before deregulation" and the 1997–2001 "after deregulation." The assessment found that major changes related to LOOPs after deregulation compared to before include the following: 1) the frequency of LOOP events at NPPs has decreased, 2) the average duration of LOOP events has increased – the percentage of LOOPs longer than four hours has increased from approximately 17 percent to 67 percent, 3) where before LOOPs occurred more or less randomly throughout the year, for 1997-2001, most LOOP events occurred during the summer, and 4) the probability of a LOOP as a consequence of a reactor trip has increased by a factor of 5 (from 0.002 to 0.01)..

Simplified event trees were developed to assess the impact of these changes on overall NPP risk, and to include the impact of the LOOP as a consequence of reactor trip. The combined impact of the changes noted above, and the reduced frequency of reactor trips, was assessed. The findings include the following: 1) the average yearly risk from LOOPs and reactor trips decreased, 2) a small number of events over the first five years of deregulated operation indicates that most of the risk from LOOPs occurs during the summer, and 3) including LOOP as a consequence of a reactor trip and the potential for degraded grid during the summer, the risk associated with an EDG out of service can be larger than previously realized.

The assessment re-enforces the need for NPP licensees and NRC to understand the condition of the grid throughout the year to assure that the risk due to potential grid conditions remains acceptable. To elaborate:

(1) The NRC does not regulate the grid; however, the performance of offsite power is a major factor for assessment of risk. With respect to maintaining the current levels of safety, offsite power is especially important with regard to the risk associated with EDG maintenance and outage activities. Consequently, NRC and licensee assessments of risk that support EDG maintenance and outage activities should include: (a) assessment of offsite power system reliability, (b) the potential for a consequential LOOP given a reactor trip, and (c) the potential increase in the LOOP frequency in the summer (May to September). Regarding (a) above, the assessment of the power system reliability and risks from plant activities can be better managed though coordination of EDG tests with transmission system operating conditions.

(2) Another important aspect of the changes to the electrical grid is the impact on the electrical analyses of NPP voltage limits and predictions of voltages following a reactor trip and whether a reactor trip will result in a LOOP. Recent experience shows that actual grid parameters may be worse than those assumed in electrical analyses due to transmission system loading, equipment out-of-service, lower than expected grid reactive capabilities, and lower grid operating voltage limits and action levels. NPP design basis electrical analyses used to determine plant voltages should use electrical parameters based on realistic estimates of the impact of those conditions.

(3) With the structural and operational changes that have occurred in the industry, it is important to have mechanisms, such as contracts between the NPP and transmission company, in place to ensure that grid operators will provide reliable electrical power. Some regional grid operating entities manage and control operational and engineering activities in real time to maintain grid availability and reliability. Since external factors impact the ability of licensees to manage risks and understand the condition of the grid, some NPP licensees have implemented contractual agreements with grid operators to provide a mechanism for maintaining secure electrical power in the deregulated environment. Contractual arrangements should include specific electrical requirements, communication protocols, operating procedures and action limits, maintenance responsibilities, SBO (alternate ac) power supply responsibilities, and NPP and grid. Within its proper roles and responsibilities, the NRC should communicate with the industry about the possible need for these mechanisms.

CAISO, PJM, and Callaway experience provides an opportunity for the industry and NRC to develop lessons to be learned. The assessment identified the following insights from this experience:

(2) While the data set is small, recent experience indicates that the average duration of LOOPs has increased. Based on historical data, power restoration times following a LOOP are assumed to be less than 4 hours; most recent LOOPs have lasted significantly longer. Also, recent grid events, although not directly associated with LOOPs, indicate that grid recovery times may be longer. For example, in the Northeast, it took the grid operator (of 12 NPPs) 10 hours to resolve problems from unexpected behavior of the grid, despite implementation of planned voltage and load management programs and investigation found insufficient reactive capacity to quickly restore voltages. In the Mid-West, the grid operator needed 12 hours to change regional power flows and restore voltage to a NPP. These events support the concern identified in SECY 99-129 that the time needed to coordinate grid operations may increase in a deregulated environment.

(2) LOOPs, partial LOOPs, momentary LOOPs, and voltage degradations below the technical specification low limit following or coincident with a reactor trip may provide indication of a potential electrical weaknesses in the grid and a need for regulatory followup to prevent more serious events. In some events, plant equipment which control safety bus voltage levels, is assumed to be functional by the grid controlling entity for the range of external voltages maintained at the NPP. Periodic verification of NPP or other voltage controlling equipment operability may require compensatory measures such as a request for voltage adjustment from the grid control entity.

(3) Realistic assessment of the risk from grid events may need to consider the impact of a grid event on multiple NPPs. For example, one recent transmission system disturbance resulted in the simultaneous trip of four NPPs.

(4) Experience indicated that transmission system operation or disturbances may cause sustained or frequent current unbalances that result in damage to electrical equipment. It is common practice to protect expensive or important nonsafety equipment from current unbalances. Safety equipment does not always have the same level of protection. RES will further analyze this issue in the future.

(5) Grid-induced reactor transients can affect scram capability. Operating experience identified an instance where anticipated transient without scram mitigation based on end-of-cycle recirculation pump trip logic failed to operate correctly during a transmission system fault that produced large electrical load fluctuations. RES will further analyze this issue in the future.

(6) Grid conditions which result in over-frequency conditions can have unexpected consequences. At one plant, over-frequency conditions following a load rejection caused speed-up of the reactor coolant pumps which generated lifting forces on the core to within a small margin of causing core mechanical tilt. The over-frequency condition was not properly accounted for by the plant protective relay control logic. RES will further analyze this issue in the future.

(7) The synergistic effects of reduced reactive grid capability on the NPP from hot weather and multiple reactor power uprates should be evaluated. RES will further analyze this issue in the future.

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