June 22, 2005

EA-05-103

Mr. Christopher M. Crane
President and Chief Nuclear Officer
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2
NRC INSPECTION REPORT 05000373/2005010; 05000374/2005010
PRELIMINARY WHITE FINDING

Dear Mr. Crane:

On May 31, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed a preliminary review of the single point vulnerability within your offsite power transformer circuits. This letter and the supporting documentation (Enclosure) discusses a finding that appears to have low to moderate safety significance. As described in Section 4OA3 of this report, the finding pertains to a single point vulnerability that could result in a loss of all onsite and offsite power sources to both 4160 Vac Division 1 and Division 2 safety-related buses at either of your LaSalle County Station units. This finding was assessed based on the best available information, including influential assumptions, using the applicable Significance Determination Process (SDP) and was preliminarily determined to be a White finding. The final resolution of this finding will convey the increment in the importance to safety by assigning the corresponding color, i.e., White, a finding with some increased importance to safety, which may require additional inspection. This single point vulnerability was reported to the NRC by you pursuant to the requirements of 10 CFR 50.73 on March 28, 2005, as Licensee Event Report (LER) 2005-001. The results of the preliminary review were discussed on June 1, 2005, with the Site Vice President, Ms. Susan Landahl, and other members of your staff.

The inspection examined activities conducted under your licenses as they relate to safety and to compliance with the Commission's rules and regulations and with the conditions of your licenses. Specifically, this inspection focused on the single point vulnerability within your offsite power transformer circuits identified by your staff on February 2, 2005, and your subsequent corrective actions. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

At approximately 3:42 p.m. on February 2, 2005, plant operators determined that they should enter a 12-hour Technical Specification Required Action for the unavailability of offsite and onsite power systems. A licensee analysis of the issue determined that the current transformer (CT) circuits that supply the overcurrent relay scheme for each divisional bus were connected to a common point that supplies control room indication for the total station auxiliary transformer (SAT) 'Y' winding power (kW) and current (amperes). Further, your engineering staff determined that an open circuit condition on any of the CT phases downstream of the common point in the circuit would have initiated a trip of the associated SAT feed breakers for the applicable buses (e.g., 141Y, 142Y, 241Y and 242Y). Following a trip of the bus feed breakers, the lockout relay for the respective bus would have initiated a trip of the other bus breakers and prevented any closure of these breakers. The ultimate result would have been a loss of all onsite and offsite power sources to both 4160 Vac Division 1 and Division 2 safety-related buses, because no emergency diesel generator (EDG) or offsite power source would have been permitted to close onto the respective Division 1 or Division 2 safety buses. Division III (High Pressure Core Spray) remained available and unaffected by this event.

In response to the identification of this condition on each unit, a temporary modification was developed and installed by your engineering and electrical maintenance groups to isolate the common metering circuitry between the Division 1 and Division 2 buses responsible for the single point vulnerability while long term corrective actions were developed.

Be advised that this significance assessment is preliminary. The final significance assessment will include consideration of any further information or perspectives you provide that may warrant reconsideration of the methodology or assumptions used during the preliminary significance assessment. As outlined in Section 06.06 of Inspection Manual Chapter 0305 and based on the information we currently have, this finding appears to meet the criteria for consideration as an old design issue.

The finding is also an apparent violation of 10 CFR Part 50, Appendix B, Criterion III, for the failure to assure applicable regulatory requirements and the design basis for a safety-related system were correctly maintained and controlled commensurate with the standards applied to the original design.

Before the NRC finalizes this significance determination, we are providing you an opportunity (1) to present to the NRC your perspectives on the facts and assumptions used by the NRC to arrive at the finding and its significance at a Regulatory Conference; or (2) submit your position on the finding to the NRC in writing.

If you request a Regulatory Conference, it should be held within 30 days of the receipt of this letter and we encourage you to submit supporting documentation on the docket at least 1 week prior to the conference in an effort to make the conference more effective. If a Regulatory Conference is held, it will be open for public observation. If you decide to submit only a written response, such a submittal should be sent to the NRC within 30 days of the receipt of this letter.

Please contact Bruce Burgess at 630-829-9629 within 10 business days of the date of receipt of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision and you will be advised via separate correspondence of the results of our deliberations on this matter.

Since the NRC has not made a final determination in this matter, no Notice of Violation is being issued for the inspection finding at this time. In addition, please be advised that the characterization of the apparent violation described in this letter may change as a result of further NRC review.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at: http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Mark A. Satorius, Director
Division of Reactor Projects

Docket Nos. 50-373; 50-374
License Nos. NPF-11; NPF-18

Enclosure: Inspection Report 05000373/2005010; 05000374/2005010
w/Attachment: Supplemental Information

cc w/encl: Site Vice President - LaSalle County Station
LaSalle County Station Plant Manager
Regulatory Assurance Manager - LaSalle County Station
Chief Operating Officer
Senior Vice President - Nuclear Services
Senior Vice President - Mid-West Regional Operating Group
Vice President - Mid-West Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing - Mid-West Regional Operating Group
Manager Licensing - Clinton and LaSalle
Senior Counsel, Nuclear, Mid-West Regional Operating Group
Document Control Desk - Licensing
Assistant Attorney General
Illinois Department of Nuclear Safety
State Liaison Officer
Chairman, Illinois Commerce Commission

See Previous Concurrences

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REGION III

Docket Nos:	50-373; 50-374
License Nos:	NPF-11; NPF-18
Report No:	05000373/2005010; 05000374/2005010
Licensee:	Exelon Generation Company, LLC
Facility:	LaSalle County Station, Units 1 and 2
Location:	2601 N. 21st Road Marseilles, IL 61341
Dates:	February 1 through May 31, 2005
Inspectors:	D. Kimble, Senior Resident Inspector D. Eskins, Resident Inspector S. Burgess, Senior Reactor Analyst L. Kozak, Senior Reactor Analyst J. Yesinowski, Illinois Dept. of Emergency Management
Approved by:	Bruce L. Burgess, Chief Branch 2 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000373/2005010, 05000374/2005010; 02/01/2005 - 05/31/2005; LaSalle County Station, Units 1 & 2; Event Follow-up.

The report covered the follow-up inspection activities for a Licensee Event Report. The inspection was conducted by the resident inspectors. This inspection identified a preliminary White finding and associated apparent violation (AV). The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be “Green” or be assigned a severity level after NRC management review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealed Findings

Cornerstones: Initiating Events and Mitigating Systems

TBD. An apparent violation having a preliminary low to moderate safety significance was identified during the licensee’s review of a similar issue identified at Crystal River Nuclear Plant Unit 3 on January 27, 2005. A design deficiency in a metering circuit for the site’s normal 4160 volts-alternating current (Vac) offsite power supply induced a vulnerability whereby a single fault in the metering circuitry, for a given unit, could have resulted in the loss of all Division 1 and Division 2 safety-related 4160 Vac power on a given unit.

The finding was determined to be greater than minor because it impacted both the Initiating Events and Mitigating Systems Cornerstones. The finding was preliminarily determined to be of low to moderate safety significance following the performance of a case-specific Phase 3 SDP. Corrective actions taken by the licensee included installing temporary modifications on each unit to remove the metering circuitry in question. (Section 4OA3)

B. Licensee-Identified Violations

No violations of significance were identified.

REPORT DETAILS

4. OTHER ACTIVITIES

Cornerstones: Initiating Events and Mitigating Systems

4OA3 Event Follow-up (71153)

(Closed) Unresolved Item 05000373/2005002-10; 05000374/2005002-10: Single Failure Vulnerability of Safety-Related 4160 Vac Division 1 and Division 2 Protective Relay Circuitry Emergency Notification System (ENS) 41366

(Closed) Licensee Event Report (LER) 05000373/2005-01-00; 05000374/2005-01-00: Single Failure Vulnerability of Division 1 and Division 2 Protective Relay Circuitry Due to Latent Design Deficiency

a. Inspection Scope

On January 27, 2005, a single failure was discovered at Crystal River Unit 3 (CR-3) that could prevent both emergency diesel generators (EDGs) and both offsite power sources from supplying power to their respective engineered safeguards (ES) buses. This was a condition reportable under 10 CFR 50.72 (b)(3)(ii)(B), for a plant being in an unanalyzed condition that significantly degraded plant safety (ENS 41362).

The LaSalle Station Electrical System Engineering Supervisor was informed of the CR-3 event on February 1, 2005, and was provided a copy of ENS 41362 by the LaSalle Station NRC Senior Resident Inspector. LaSalle Station engineers reviewed the safety-related bus protective relaying circuitry to determine if a similar vulnerability existed. The following day, plant engineers determined that a single failure vulnerability existed for LaSalle between the current transformer (CT) circuits of the divisional safety-related buses (e.g., 141Y, 142Y, 241Y and 242Y).

Upon notification of the discovery and subsequent entry into a 12-hour Technical Specification Required Action potentially leading to the shutdown of both LaSalle units, inspectors responded to the plant to monitor the licensee's actions. The inspectors observed plant parameters and status; evaluated the performance of plant systems and licensee actions; and confirmed that the licensee properly reported the event as required by 10 CFR 50.72. The inspectors determined that all systems responded as intended, and that no human performance errors complicated the event response.

The inspectors' review and closure of this LER constituted a single inspection sample.

b. Findings

Introduction

A finding with a low to moderate preliminary safety significance (White) was identified following review of an LER that communicated to the NRC a design deficiency in the 4160 Vac station auxiliary transformer (SAT) metering circuitry. An associated apparent violation of the requirements of 10 CFR 50, Appendix B, Criterion III, “Design Control,” was also identified.

Description

At approximately 3:42 p.m. on February 2, 2005, plant operators determined that they should enter 12-hour Technical Specification Required Action for unavailability of offsite and onsite power systems. A licensee analysis of the issue determined that the CT circuits that supply the overcurrent relay scheme for each divisional bus were connected to a common point that supplies control room indication for the total SAT ‘Y’ winding power (kW) and current (amperes). Further, licensee engineers determined that an open circuit condition on any of the CT phases downstream of the common point in the circuit would have resulted in an unbalanced current condition, which would have initiated a trip of the associated SAT feed breakers for the applicable buses (e.g., 141Y and 142Y, 241Y and 242Y). Specifically, the current unbalance would have actuated the ground fault relays, causing the SAT feed breaker relays to lock out both divisions. Following a trip of the bus feed breakers, the lockout relay for the respective bus would have initiated a trip of the other bus breakers and prevented any closure of these breakers. The ultimate result would have been a loss of all onsite and offsite power sources to both 4160 Vac Division 1 and Division 2 safety-related buses, because no EDG or offsite power source would have been permitted to close onto the respective Division 1 or Division 2 safety buses.

A temporary modification was developed and installed on each unit to isolate the common metering circuitry between the Division 1 and Division 2 buses responsible for the single point vulnerability. These modifications were installed and Technical Specification Required Actions exited on Unit 1 in 7 hours, 23 minutes, and on Unit 2 in 6 hours, 48 minutes. All actions were monitored by the inspectors. The licensee entered this issue into their corrective action program as Issue Report (IR) 297076, and into their corporate corrective action program as IR 299641.

Analysis

In accordance with IMC 0612, the inspectors determined that the licensee failed to appropriately control the design of modifications affecting the Division 1 and Division 2 4160 Vac safety-related buses on each unit per regulatory requirements. This performance deficiency resulted in a single failure vulnerability that would result in the loss of all offsite and onsite AC power to both divisions of safety-related distribution buses.

Phase 1 Screening Logic, Results, and Assumptions

The inspectors determined that the issue was more than minor because it was associated with the design control attributes of both the initiating events and mitigating systems cornerstones of the reactor safety strategic performance area. The issue affected both the initiating events objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations, and the mitigating systems objective to ensure the availability, reliability, and capability of systems that respond to initiating events.

In accordance with IMC 0609, Appendix A, the inspectors conducted an SDP Phase 1 screening and determined that the finding degraded both the Initiating Events Cornerstone and Mitigating Systems Cornerstone. Because the issue degraded two or more cornerstones, a Phase 2 analysis was required.

Phase 2 Risk Evaluation

The performance deficiency may result in an increased likelihood of a transient without power conversion system (PCS) and a loss of offsite power (LOOP). In both cases, all alternating current (AC) power is unavailable to support mitigation systems with the exception of high pressure core spray (HPCS), powered by the Division III EDG, and reactor core isolation cooling (RCIC), which is supported by station batteries with no dedicated battery chargers. The Phase 2 analysis results in a RED risk characterization. However, because this issue involves an extremely narrow window of vulnerability (failure probability of a highly reliable component), the Phase 2 worksheets for LaSalle do not appropriately characterize the risk significance of this event and are overly conservative in their estimation of the risk. Because of the high reliability of components that could fail to give a CT open circuit, the initiating event frequency of a LOOP or a transient without PCS would not be increased by one order of magnitude. Therefore, a Phase 3 analysis was required to characterize the risk significance of this issue.

Phase 3 Risk Analysis

The NRC's senior risk analysts (SRAs) performed a risk evaluation of the LaSalle single failure vulnerability using the standardized plant analysis risk (SPAR) model, version 3.11, and generic failure probabilities obtained from the Office of Nuclear Reactor Regulation (NRR). SPAR was run using a LOOP event with both safety-related buses assumed unavailable to obtain a conditional core damage probability (CCDP) of 1.3E-3. No specific SPAR model changes were made, as a general risk characterization was desired. Assuming that the single failure (CT open circuit) had a failure rate of 1.0E-6/hr, the condition existed for a year, and assuming a conservative recovery credit of 1E-1, the change in core damage frequency (Δ CDF) was 1.1E-6/yr (White).

Potential Risk Contribution Due to Large Early Release Frequency (LERF)

Using IMC 0609, Appendix H, the SRA determined that this was a Type A finding for a Mark II containment. Using Table 5.2, the reactor coolant system (RCS) would be at a high pressure during the station blackout (SBO) condition; therefore, a LERF factor of 0.3 was applied to the Phase 3 calculated Δ CDF. The resultant Δ LERF was 3.3E-7 (White). In this case, Δ LERF did not change the risk characterization by an order of magnitude.

Licensee's Analysis

Internal Events

Based on the licensee's internal events risk assessment, the Δ CDF was calculated at 1.82E-6/yr. In determining the failure probability of the CT circuitry, the licensee used both a fault tree analysis and an analysis of industry operating data. The annual initiating event frequency of the postulated CT circuitry failure scenarios was of low frequency, in the low 1E-4/yr to low 1E-3/yr range depending upon the methodology used in the calculation and the assumptions. The licensee determined the best estimate frequency was that calculated using the industry experience data, which was 1.2E-4/yr. The licensee also performed eleven sensitivity studies. The SRAs reviewed the licensee's analysis and agreed with the assumptions and the methodology used.

LERF Contribution

The licensee's LERF analysis determined that the Δ LERF for internal events, fire scenarios, and seismic scenarios was 3.4E-7/yr, which was consistent with a White risk characterization and would not change the overall White risk characterization of this finding.

Potential Risk Contribution Due to External Events

The licensee evaluated external event contributions and determined that external hazards such as flooding, transportation, chemical spills, etc., were not considered credible events that could have lead to a circuit fault.

Earthquake

Seismic-induced CT failures of interest were based on the likelihood of a seismic event being of sufficient magnitude to shake the subject panel of interest (located in the main control room) enough to create an open circuit CT failure. This was judged to be an unlikely occurrence; however, the licensee did quantitatively calculate the CDF for the seismic open circuit as 6.3E-8.

Fire

Fire-induced CT failures were considered as the most likely credible initiating event that could potentially cause the CT failure. The CT circuitry was located in the main control room and contained electrical circuits for operating the EDGs, bus-tie breakers, unit auxiliary transformer (UAT) feed breakers, and SAT feed breakers. Panels for HPCS and RCIC were located across the room from the CT panels. Based on the licensee's fire analysis, the total contribution for fire-induced open circuit scenarios was 9.5E-8.

The licensee's initiating event frequency for main control room cabinets was approximately one order of magnitude lower than the fire protection SDP result; however, the SDP took into account the entire main control room and not simply the electrical panels of interest. The severity factor and non-suppression factor were also consistent with the SDP, and the licensee did not take much credit for mitigating systems. The SRAs determined that the overall analysis was acceptable.

Licensee Analysis Conclusion

The licensee's total Δ CDF considering internal events, LERF considerations, and external events was 2E-6/yr, indicating a finding of low to medium safety significance (White).

Significance Determination Conclusion

The NRC's calculation of the Δ CDF was based on generic CT open circuit failure assumptions and on conservative recovery actions. Based on a review of the licensee's analysis using industry component failure data, reasonable operator recovery actions, plant-specific fire analysis, and plant-specific seismic analysis, the NRC SRA's recommended a White risk characterization for this finding. The SPAR analysis obtained similar results indicating that the risk characterization was appropriate.

Enforcement

10 CFR 50, Appendix B, Criterion III requires, in part, that design changes, including field changes, shall be subject to design control measures commensurate with those applied to the original design.

10 CFR 50, Appendix A, General Design Criterion 17, requires, in part, that onsite electric power supplies, including the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Contrary to the above, modifications made to the emergency diesel generation (EDG) output circuit breakers that were completed on December 21, 1988, for Unit 2, Division 1; September 26, 1989, for Unit 1, Division 1; March 8, 1991, for Unit 1, Division 2; and February 1, 1992, for Unit 2, Division 2 did not contain design control measures commensurate with those applied to the original design. Specifically, the design change introduced a single failure vulnerability such that a failure (i.e., open circuit) of the common CT circuit would have resulted in all loss of all AC, including the EDG supplied feeds, for the Division 1 and Division 2 safety buses on both Units.

The original issue associated with this finding was identified by an NRC inspection team at CR-3 and, within NRC Region III, the issue was first brought to the attention of the licensee by inspectors at Clinton, Dresden, and Quad Cities Stations on Monday, January 31, 2005, and at LaSalle County Station by the NRC Senior Resident Inspector on Tuesday, February 1, 2005. Although the interactions between licensee site personnel and the inspectors accelerated the licensee's examination of the issue at each site and perhaps prompted a more thorough examination than might have otherwise taken place, the inspectors determined that in all likelihood the licensee's own internal operating experience program would have triggered the licensee to have looked into the issue in due course. As a result, the finding was considered licensee-identified for enforcement purposes.

Following identification of the single point vulnerability by the Electrical Engineering Group at LaSalle Station, the licensee took prompt action to remove the vulnerability on each unit via the temporary modification process. These temporary modifications were completed in less than 8 hours on each unit, and within the Technical Specification Allowed Outage Time limit. A plant modification was performed during the February-March 2005 Unit 2 refuel outage to permanently eliminate the vulnerability on Unit 2. On Unit 1, the temporary modification will remain in place until the 2006 Unit 1 refuel outage when a permanent plant modification will be installed on that unit.

The inspectors determined that normal licensee surveillances and QA activities were not likely to have identified the vulnerability. Because the metering circuits connecting the Division 1 and Division 2 buses have existed from the time of original construction and the modifications to the EDG breakers occurred over 10 years ago, the performance errors that caused the issue were determined not to be representative of licensee present day performance.

4OA6 Meetings

Exit Meeting

The inspectors presented the inspection results to the Site Vice President, Ms. S. Landahl, and other members of licensee management on June 1, 2005. The inspectors asked the licensee about proprietary information associated with the inspection; no proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

S. Landahl, Site Vice President
D. Enright, Plant Manager
T. Connor, Maintenance Director
L. Coyle, Operations Director
D. Czufin, Site Engineering Director
C. Dieckmann, Training Manager
A. Ferko, Nuclear Oversight Manager
F. Gogliotti, System Engineering Manager
P. Holland, Regulatory Assurance - NRC Coordinator
B. Kapellas, Radiation Protection Manager
H. Madronero, Engineering Programs Manager
W. Riffer, Emergency Planning Manager
T. Simpkin, Regulatory Assurance Manager

Nuclear Regulatory Commission

B. Burgess, Chief, Reactor Projects Branch 2

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000373/2005010-01; 05000374/2005010-01	AV	Failure to Maintain Required Design Redundancy Against a Single Failure Involving Safety-Related 4160 Vac Division 1 and Division 2 Bus Metering Circuitry (Section 4OA3)

Closed

05000373/2005002-10; 05000374/2005002-10	URI	Single Failure Vulnerability of Safety-Related 4160 Vac Division 1 and Division 2 Protective Relay Circuitry (ENS 41366) (Section 4OA3)
05000373/2005-01-00; 05000374/2005-01-00	LER	Single Failure Vulnerability of Division 1 and Division 2 Protective Relay Circuitry Due to Latent Design Deficiency (Section 4OA3)

Discussed

None.

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety, but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

<u>4OA3</u> <u>Event Follow-up</u>

Modifications:
- M1-1-86-085; Emergency Diesel Generator No. 0, Unit 1; 9/26/1989
- M1-1-84-018; Emergency Diesel Generator No. 1A, Unit 1; 3/8/1991
- M1-2-84-031; Emergency Diesel Generator No. 2A, Unit 2; 2/1/1992
- M1-2-86-093; Emergency Diesel Generator No. 0, Unit 2; 12/21/1988

Issue Reports:
- 299188; Lack of Minimum 6-Inch Physical Separation in Division 1 and 2 CTs; 2/8/2005
- 297076; Vulnerability of Division 1 and 2 Protective Relay Circuitry; 2/2/2005

Operability Evaluation:
- OE 05-001; Vulnerability of Division 1 and 2 Protective Relay Circuitry; Revision 0

Exelon Risk Management Team Report on the Risk Significance of the Single Point Vulnerability; Revision 0

Root Cause Report:
- 299641; Single Failure Vulnerability of Safety-Related Division 1 and 2 Protective Relay Circuitry; 3/8/2005

Temporary Modifications:
- EC 353657; TCCP to Isolate Metering Common to 141Y/142Y and 241Y/242Y Safety-Related Buses; 2/2/2005

Drawings and Prints:
- 1E-2-4000PG; Relaying & Metering Diagram – 4160 Vac Switchgear 241Y; Revision L
- 1E-1-4000PJ; Relaying & Metering Diagram – 4160 Vac Switchgear 142Y; Revision M
- 1E-1-4000PG; Relaying & Metering Diagram – 4160 Vac Switchgear 141Y; Revision N
- 1E-2-4000PJ; Relaying & Metering Diagram – 4160 Vac Switchgear 242Y; Revision K

LIST OF ACRONYMS USED

AC	Alternating Current
AV	Apparent Violation
CCDP	Conditional Core Damage Probability
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CR-3	Crystal River Unit 3
CT	Current Transformer
EDG	Emergency Diesel Generator
ENS	Emergency Notification System
ES	Engineered Safeguards
HPCS	High Pressure Core Spray
IMC	Inspection Manual Chapter
IR	Issue Report
kW	Kilowatts
LER	Licensee Event Report
LERF	Large Early Release Frequency
LOOP	Loss of Offsite Power
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
PCS	Power Conversion System
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
SAT	Station Auxiliary Transformer
SBO	Station Blackout
SDP	Significance Determination Process
SPAR	Standardized Plant Analysis Risk
SRA	Senior Risk Analyst
UAT	Unit Auxiliary Transformer
URI	Unresolved Item
Vac	Volts - Alternating Current