UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

November 15, 2012

Mr. T. Preston Gillespie, Jr.
Site Vice President
Duke Energy Corporation
Oconee Nuclear Station
7800 Rochester Highway
Seneca, SC 29672-0752

SUBJECT: OCONEE NUCLEAR STATION – INTEGRATED INSPECTION REPORT 05000269/2006002, 05000270/2006002, 05000287/2006002 ERRATA

Dear Mr. Gillespie:

On April 28, 2006, the US Nuclear Regulatory Commission (NRC) issued the subject quarterly inspection report for the Oconee Nuclear Station, ADAMS accession ML061180451. In reviewing this report, it was noted that we inadvertently included official use only, security related information in the report. Accordingly, we are providing a revised version of the report that removes this information.

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 http://www.nrc.gov/NRC/ADAMS/index.html. (The Public Electronic Reading Room).

I apologize for any inconvenience this error may have caused. If you have any questions, please contact me at (404) 997-4607.

Sincerely,

/RA/

Jonathan Bartley, Chief
Reactor Projects Branch 1
Division of Reactor Projects

Docket Nos.: 50-269, 50-270, 50-287
License Nos.: DPR-38, DPR-47, DPR-55

Enclosure: NRC Integrated Inspection Report 05000269/2006002,05000270/2006002, 05000287/2006002 w/Attachment: Supplemental Information

cc w/encl: (See page 2)

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Letter to T. Preston Gillespie, Jr. from Jonathan H. Bartley dated November 15, 2012

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-269, 50-270, 50-287
License Nos.:	DPR-38, DPR-47, DPR-55
Report No:	50-269/2006002, 50-270/2006002, 50-287/2006002
Licensee:	Duke Energy Corporation
Facility:	Oconee Nuclear Station, Units 1, 2, and 3
Location:	7800 Rochester Highway Seneca, SC 29672
Dates:	January 1, 2006 - March 31, 2006
Inspectors:	M. Shannon, Senior Resident Inspector A. Hutto, Resident Inspector E. Riggs, Resident Inspector A. Vargas-Mendez, Reactor Inspector (Section 4OA5.3)
Approved by:	D. Charles Payne, Acting Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000269/2006002, IR 05000270/2006002, IR 05000287/2006002, 01/01/2006 - 03/31/2006; Oconee Nuclear Station, Units 1, 2, and 3; Other Activities.

The report covered a three-month period of inspection by the onsite resident inspectors and an in-office review by a reactor inspector of the results of an NRC Office of Investigations report. A severity level (SL) IV non-cited violation was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using 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-Revealing Findings

Cornerstone: Barrier Integrity

- SL IV. An in-office review of the results of NRC Office of Investigations (OI) Report No.: 2-2005-016, identified a non-cited violation of 10 CFR 50.9 for failure to provide complete and accurate information in Licensee Event Report (LER) 05000287/2001-001, regarding the condition of the Unit 3 Reactor Pressure Vessel Head (RPVH), resulting from boric acid leakage. The LER stated that boric acid leakage caused no detectable corrosion to the vessel head, when in fact some minor corrosion was identified. The licensee corrected the incomplete and inaccurate information with a revision to LER 05000287/ 2001-001, dated August 18, 2005.

  Because this issue potentially affected the NRC's ability to perform its regulatory function, it was evaluated using the traditional enforcement process. The failure to provide accurate and complete information precluded the NRC from being able to pursue or consider further inquiry or inspection activity in regards to RPVH corrosion, the significance of which was not known at the time. NRC review determined that there was no evidence that the licensee's actions were willful. Additionally the NRC determined that the corrosion was not structurally significant and would not have resulted in a regulatory action or substantial further inquiry. (Section 4OA5.3)

B. Licensee-Identified Violations

One violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation is listed in Section 4OA7.

REPORT DETAILS

Summary of Plant Status:

Unit 1 entered the report period at 100 percent rated thermal power (RTP). On January 28, 2006, the unit was reduced to approximately 88 percent RTP to perform turbine valve movement testing, and was returned to 100 percent RTP on the same day. The unit operated at or near 100 percent RTP for the remainder of the inspection period.

Unit 2 entered the report period at 100 percent RTP. On February 25, 2006, the unit was reduced to approximately 88 percent RTP to perform startup functional testing of the Triconex electro-hydraulic control (EHC) system upgrade, and was returned to 100 percent RTP on the same day. The unit operated at or near 100 percent RTP for the remainder of the inspection period.

Unit 3 entered the report period at 100 percent RTP. On February 4, 2006, the unit was reduced to approximately 88 percent RTP to perform turbine valve movement testing, and was returned to 100 percent RTP on the same day. The unit operated at or near 100 percent RTP for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

The inspectors conducted partial equipment alignment walkdowns to evaluate the operability of selected redundant trains or backup systems while the other train or system was inoperable or out of service. The walkdowns included, as appropriate, reviews of plant procedures and other documents to determine correct system lineups, and verification of critical components to identify any discrepancies which could affect operability of the redundant train or backup system. The following four systems were included in this review:

- The A high pressure service water (HPSW) pump with the B pump out of service (OOS) for preventive maintenance
- Unit 1, 2 and 3 high pressure injection (HPI) systems and the standby shutdown facility (SSF) with the station auxiliary service water (ASW) pump OOS for rotating element replacement
- Unit 3 B Train of low pressure injection (LPI) during 3LP-21 preventive maintenance

b. Findings

No findings of significance were identified.

.2 Complete Walkdown of the Unit 1 125 VDC and 120 VAC Vital Power Systems

a. Inspection Scope

The inspectors performed a system walkdown on accessible portions of the Unit 1125 VDC and 120 VAC vital power systems and associated support systems. This included the control batteries, vital DC distribution panels, vital inverters and the isolating transfer diodes. The inspectors focused on verifying proper breaker positioning, panel indications, power availability, no damage to cabling or cable tray structural supports, and material condition.

A review of Problem Investigation Process reports (PIPs) and open maintenance work orders was performed to verify that any material condition deficiencies or outstanding maintenance did not significantly affect the vital power system's ability to perform its design functions and that appropriate corrective actions were being taken by the licensee.

The inspectors conducted a review of the system engineer's trending data and system health reports to verify that appropriate trending parameters were being monitored and that no adverse trends were noted. Reviewed documents are listed in Section 1R04.2 of the report Attachment.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Fire Area Walkdowns

a. Inspection Scope

The inspectors conducted tours in 13 areas of the plant to verify that combustibles and ignition sources were properly controlled, and that fire detection and suppression capabilities were intact. The inspectors selected the areas based on a review of the licensee's safe shutdown analysis and the probabilistic risk assessment based sensitivity studies for fire-related core damage sequences. Inspections of the following 13 areas were conducted during this inspection period:

- Unit 1, 2 and 3 Control Rooms (3)
- Unit 1, 2 and 3 Power Battery Rooms (3)
- Unit 1, 2 and 3 Auxiliary Building Ventilation Rooms (3)
- Unit 1, 2 and 3 Control Room Ventilation Rooms (2)
- Unit 1 and 3 Cable Spreading Rooms (2)

b. Findings

No findings of significance were identified.

.2 Fire Drill Observation

a. Inspection Scope

The inspectors observed the fire drill conducted on January 25, 2006, to assess the readiness of the licensee's capability to fight fires. The fire was simulated in the Unit 1 Equipment Room. The inspectors evaluated the drill for the following attributes:

- protective clothing/self-contained breathing apparatus properly worn
- adequacy/appropriateness of fire extinguishing methods
- controlled access to the fire area by the fire brigade members
- adequacy of fire fighting equipment
- command and control effectiveness of the fire brigade leader
- adequate communications
- effectiveness of smoke removal gear

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (external)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) sections 2.4, Hydrologic Engineering, and 9.6, Standby Shutdown Facility, and the SSF ASW Design Basis Documents sections 2.2.5, Design Events, and 2.3.13, Flood, with regard to protecting the SSF from external flooding. The inspectors performed a walkdown of the SSF to examine its flood protection features and barriers including the flood wall and watertight door at the South entrance of the SSF, accessible cable and piping penetrations and seals, structural integrity of the building with regards to external flooding, and the building's floor drain and sump system.

b. Findings

(8) Breach of SSF Flood Protection Barrier

Introduction: An unresolved item (URI) was identified for failure to maintain design control of a SSF flood protection barrier, which resulted in the creation of a 6" x 10" pathway for external flood waters to enter the SSF and potentially render its equipment inoperable. This issue is designated as a URI pending further inspection and assessment of the affect of the breached flood protection barrier on SSF equipment.

Description: On August 13, 2003, per work order (WO) 98609803, the licensee removed an access cover on the bolted cover that surrounds the CO_2 supply pipe located in the Southwest corner of the SSF Response Room. This 6" x 10" cover is a passive flood protection barrier and was removed to route temporary power cables into the SSF for an SSF outage.

On June 2, 2005, as a result of the inspectors observations, the licensee generated PIP O-05-3820 to document that the flood protection barrier was breached to route temporary power cables into the SSF in support of modification work. On August 3, 2005, the licensee generated PIP O-05-4978, which documented that the deficient condition still existed, as the temporary power cables were still routed through the breached flood protection barrier, located on the South wall of the SSF and below the top of the flood barriers at the North and South entrances to the SSF. PIP O-05-4978 goes on to state that, "Based on discussions with. . .Severe Accident Analysis Group, the bolted cover over the CO_2 supply pipe should be installed because it is part of the flood barrier that protects the SSF. While this flood barrier is not required for SSF operability, it is important to PRA [Probabilistic Risk Assessment] (similar to flood gate at the South Entrance to the SSF)." On August 3, 2005, per work request (WR) 98352428, the temporary power cables were removed and the flood protection barrier was restored to its design configuration.

As a result of a licensee investigation into the breached flood protection barrier, the licensee updated section 2.2.5.2.2 of the SSF ASW design basis document (DBD), External Flooding Due To Jocassee Dam Failure, to read…in order to protect the SSF from flooding due to a Jocassee Dam failure which results in flood levels less than the SSF flood barrier [at the South entrance of the SSF],. . .The bolted cover that surrounds the CO_2 supply pipe located in the Southwest corner of the SSF Response Room must be installed. The bolted access panel that is located on the CO_2 supply pipe bolted cover must also be installed. Additionally, the licensee posted signage next to the access cover which states, "Do not remove bolted cover that surrounds CO2 supply pipe in SSF Response Room when the SSF is operable. Bolted cover is a flood barrier for the SSF."

PIPs O-05-4978 and O-05-6642 document that the Maintenance Rule expert panel changed the maintenance rule function of providing external flood protection barriers for the SSF to High Safety Significance, and included the bolted cover that surrounds the CO_2 supply pipe and its access cover in this function. The licensee classified this event as a maintenance preventable functional failure for external flood protection of the SSF. The Maintenance Rule portion of PIP O-05-4978 states that, "When the flood barrier for the CO_2 supply pipe located inside the SSF Response Room is not installed, the SSF is vulnerable to external flood water that exceeds the height of the resulting opening. Since the height of the opening that is present when the flood barrier. . .is removed is below the height of the flood gate provided at the South entrance to the SSF, a functional failure of the SSF flood protection barrier would occur for flood levels that reach the height of the opening."

Licensee calculation OSC-2240, Verification of SSF Sump System Parameters - NSM ON-1012, documents that the SSF sump pumps cannot be relied on to operate following a Jocassee Dam failure, as the pump's are incapable of developing sufficient head to overcome the backpressure developed by the depth of the flood waters and that approximately 5920 gallons of water in the SSF pump room will render the SSF inoperable.

Section 9.6.4.7 of the UFSAR discusses "Flooding Reviews" with respect to SSF System Evaluations, and states that, "The structure meets the requirements of GDC 2 [Design bases for protection against natural phenomena], and the guidelines of Regulatory Guide 1.102 [Flood Protection for Nuclear Power Plants] with respect to protection against flooding."

However, section 2.2.5.2.2 of the SSF ASW DBD, External Flooding Due To Jocassee Dam Failure, stated that an external flood wall was added around the SSF entrances to reduce the consequences of a Jocassee Dam failure. This wall was not intended to bound all flood scenarios, but was deemed adequate to protect the SSF from the more likely flood scenarios. A recently completed flood analysis indicates that a Jocassee Dam failure could result in an external flood height greater than the external flood wall. In this case, the deficient flood protection barrier was located below the top of the flood protection wall located at the South entrance of the SSF, and would have provided a flowpath for external flood waters whose depth was greater than 4.6 feet to enter the SSF.

Additionally, a December 10, 1992, Jocassee Dam Failure Inundation Study (Federal Energy Regulatory Commission Project No. 2503) predicted that a Jocasee Dam failure could result in flood waters higher than the external flood wall.

Analysis: During an external flooding event, the breached flood protection barrier could have provided a flowpath for flood waters to enter the SSF. This could impact the safety function of the SSF during accident scenarios that require the use of SSF equipment to mitigate the consequences of the event, as the flood waters could have rendered the SSF equipment inoperable.

Enforcement: This issue remains unresolved pending further inspection and assessment to determine what impact the breached flood protection barrier may have had on SSF equipment during a postulated event requiring the use of the SSF. Accordingly, it will be identified as: URI 05000269,270,287/2006002-01, Failure to Maintain Design Control of SSF Flood Protection Barrier. This issue is in the licensee's corrective action program as PIPs O-05-3820, O-05-4978 and O-05-6642.

(9) Bypass of SSF Flood Protection Barrier

Introduction: An URI was identified for failure to promptly identify an inadequate design feature of the SSF Building Sewer system which resulted in an open pathway for external flood waters to enter the SSF and render its equipment inoperable. This issue is designated as a URI pending further inspection and assessment of the effects of flood water on the SSF Building Sewer system.

Description: On January 19, 2006, while performing an extent of condition investigation for the breached SSF flood protection barrier discussed above, the inspectors discovered an apparent pathway, via the SSF Building Sewage System, for external flood waters to enter the SSF. The licensee's flow diagrams indicated the existence of a flowpath from the continuously vented sewage system lift station, which was located two feet beneath the yard grade elevation of 796 feet for the site, through the main sewage line into the SSF. This line contained no check valves. Oconee Engineering was contacted concerning the identification of the potential design deficiency, and the inspectors were told that the potential issue would be examined.

On February 8, 2006, the inspectors again contacted Oconee Engineering regarding the apparent pathway for external flood waters to enter the SSF. The inspectors were told that the potential issue would be examined that day. Later that same day, the SSF was declared inoperable and PIP O-06-0740 was generated.

As stated by the SSF System Engineer and documented in PIP O-06-0740, “This problem could affect operation of the SSF ... following a Jocassee dam failure (PRA Event).” In concurring with the operability assessment documented in PIP O-06-0740, the Operations Shift Manager stated that, “...the SSF sanitary lift station [has been] removed from service and the vent line in the sewage ejector has been capped (white-tagged by Maintenance) to prevent flooding in the SSF during the postulated Jocassee dam failure (PRA event).”

Licensee calculation OSC-2240, Verification of SSF Sump System Parameters - NSM ON-1012, documents that the SSF sump pumps cannot be relied upon to operate following a Jocassee Dam failure, as the pump’s are incapable of developing sufficient head to overcome the backpressure developed by the depth of the flood waters and that approximately 5920 gallons of water in the SSF pump room will render the SSF inoperable.

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However, section 2.2.5.2.2 of the SSF ASW DBD, External Flooding Due To Jocassee Dam Failure, stated that an external flood wall was added around the SSF entrances to reduce the consequences of a Jocassee Dam failure. This wall was not intended to bound all flood scenarios, but was deemed adequate to protect the SSF from the more likely flood scenarios. A recently completed flood analysis indicates that a Jocassee Dam failure could result in an external flood height higher than the external flood wall. However, the inadequately designed SSF Sewage system was located below the top of the flood protection wall located at the South entrance of the SSF, and would have provided a flowpath for all external flood waters to enter the SSF.

Additionally, a December 10, 1992, Jocassee Dam Failure Inundation Study (Federal Energy Regulatory Commission Project No. 2503) predicted that a Jocasee Dam failure could result in flood waters higher than the external flood wall.

<u>Analysis</u>: During an external flooding event, the open pathway provided by the inadequately designed SSF Sewer system could have provided a flowpath for flood waters to enter the SSF. This could impact the safety function of the SSF during accident

scenarios that require the use of SSF equipment to mitigate the consequences of the event, as the flood waters could have rendered the SSF inoperable.

Enforcement: This issue remains unresolved pending further inspection and assessment to determine what impact the inadequate SSF Sewer system design may have had on SSF equipment during a postulated event requiring the use of the SSF. Accordingly, it will be identified as: URI 05000269,270,287/2006002-02, Failure to Promptly Identify an Inadequate SSF Building Sewer System Design. This issue is in the licensee's corrective action program as PIP O-06-0740.

1R07 Heat Sink Performance

Annual Review

a. Inspection Scope

The inspectors observed portions of the performance test (PT) and the results of the 2A Component Cooling (CC) cooler cleaning and inspection (WO 98740067) and MP/0/A/1800/137, Cooler - Component Cooling - Disassembly, Cleaning, and Assembly. The inspectors observed the as found condition of the low pressure service water (LPSW) tube side of the cooler to verify that their was no significant biological or corrosion fouling of the heat exchange surfaces or tube blockage, and that excessive corrosion of the cooler water boxes did not exist. The inspectors also assessed the appropriateness of the heat exchanger cleaning/inspection interval based on the as found condition. The inspectors also observed the tube cleaning techniques and the as left condition of the cooler to verify the adequacy of the cleaning process and to ensure that the cooler would be able to perform its function until the next cleaning interval.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed licensed operator simulator training on March 17, 2006. Since this observation was made during the annual requalification examination, the inspector was requested to sign a non-disclosure statement. Therefore, the scenario cannot be discussed in this report pending completion of all annual requalification exams. The inspectors observed crew performance in terms of communication; ability to take timely and proper actions; prioritizing, interpreting, and verifying alarms; correct use and implementation of procedures, including the alarm response procedures; timely control board operation and manipulation, including high-risk operator actions; and oversight and direction provided by the shift supervisor, including the ability to identify and implement appropriate Technical Specification (TS) actions and properly classify the simulated event.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the licensee's effectiveness in performing routine maintenance activities. This review included an assessment of the licensee's practices pertaining to the identification, scoping, and handling of degraded equipment conditions, as well as common cause failure evaluations. For each item selected, the inspectors performed a detailed review of the problem history and surrounding circumstances, evaluated the extent of condition reviews as required, and reviewed the generic implications of the equipment and/or work practice problem. For those systems, structures, and components (SSCs) scoped in the maintenance rule per 10 CFR 50.65, the inspectors verified that reliability and unavailability were properly monitored and that 10 CFR 50.65 (a)(1) and (a)(2) classifications were justified in light of the reviewed degraded equipment condition. The inspectors reviewed the following items:

- Station ASW Pump, which included the following PIPs: O-06-0636, Station ASW Pump flow low; O-06-0637, Station ASW Pump PT/0/A/0251/010 terminated due to signs of significant cavitation, including fluctuating discharge pressure and flow
- Unit 3 Engineered Safeguards (ES) Analog Channel C power supply failures (PIPs: O-06-0122, Unit 3 ES Channel C Tripped Due to Loss of Power; O-06-0923, ES Analog Channel C DC Power Supply Breaker Tripped - Unit 3)

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Evaluations

a. Inspection Scope

The inspectors evaluated the following attributes for the seven selected SSCs and activities listed below: (1) the effectiveness of the risk assessments performed before maintenance activities were conducted; (2) the management of risk; (3) that, upon identification of an unforseen situation, necessary steps were taken to plan and control the resulting emergent work activities; and (4) that maintenance risk assessments and emergent work problems were adequately identified and resolved.

- Red ORAM risk condition, SSF declared inoperable due flood concerns through sewer system while Station ASW pump OOS for rotating element replacement
- PIP O-06-0657, NRC committed fire barriers declared inoperable due to degradation
- Station ASW Pump rotating element replacement complex plan – auxiliary building flood concerns
- Orange ORAM risk condition, CT-4 OOS for maintenance critical plan

- Orange ORAM risk condition, 3LP-21 preventive maintenance
- Yellow/Orange ORAM risk condition, 3LP-8 motor operator repairs and 3LP-22 preventive maintenance (concurrent)
- Emergent risk, PIP O-06-01722, Unit 2 AMSAC channel 2 failure

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-routine Plant Evolutions

a. Inspection Scope

The inspectors reviewed, the operating crew's performance during selected non-routine events and/or transient operations to determine if the response was appropriate to the event. As appropriate, the inspectors: (1) reviewed operator logs, plant computer data, or strip charts to determine what occurred and how the operators responded; (2) determined if operator responses were in accordance with the response required by procedures and training; (3) evaluated the occurrence and subsequent personnel response using the SDP; and (4) confirmed that personnel performance deficiencies were captured in the licensee's corrective action program. The non-routine evolutions reviewed during this inspection period included the following:

- PIP O-06-1504, Unit 1 and 2 Waste Gas Tank discharge integrator counting flow with no release in progress. PIP O-06-1592, Unit 1 and 2 Waste Gas Tank discharge integrator failed with no repair parts or replacement available. The inspector was in the control room when the instrument began malfunctioning.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed selected operability evaluations affecting risk significant systems, to assess, as appropriate: (1) the technical adequacy of the evaluations; (2) whether continued system operability was warranted; (3) whether other existing degraded conditions were considered; (4) if compensatory measures were involved, whether the compensatory measures were in place, would work as intended, and were appropriately controlled; and (5) where continued operability was considered unjustified, the impact on TS limiting condition for operations (LCOs). The inspectors reviewed the following six operability evaluations:

- PIP O-98-4808, Unit 1, 2 and 3 Turbine Driven Emergency Feedwater (TDEFW) pump's packing gland nut thread engagement appears to be inadequate
- PIP O-05-3770, PIP tracks recommended actions from Oconee SSF Risk Reduction Review, including Excessive Cycling of MSSV during postulated SSF events
- PIP O-06-0469, SSF Diesel-Generator Fuel Oil vortexing
- PIP O-06-0916, C Low Pressure Service Water (LPSW) Pump flow is less than required by test acceptance criteria
- PIP O-06-1745, Unit 1 LPI piping schedule discrepancies
- PIP O-06-1797, Pipe cap removed on suction side of 1RIA-40, breaching piping

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

Risk Significant Operator Work-Arounds

a. Inspection Scope

The inspectors reviewed three significant operator work-arounds to determine if the functional capability of the respective system or the human reliability in responding to an initiating event were affected. The inspectors specifically evaluated the affect of the operator workarounds on the ability to implement abnormal or emergency operating procedures. The inspectors also assessed what impact it would have on the unit if the work-arounds could not be properly performed.

- PIP O-06-1633, Keowee 1MT-25 Vacuum Breaker needs operator assistance to close. While observing operation of Unit 1 Keowee, the inspector noted that the vacuum breaker did not close as necessary. The vacuum breaker needs to close to prevent water intrusion into the Keowee bearing and gate control area. At present the valve needs operator assistance to re-close following operation of the Unit 1 Keowee hydro unit.

- On March 22, 2006, PIP O-06-1617 noted that the Unit 2 hotwell level indication was erratic and operators were required to obtain hotwell level locally. It also noted that it would require operators to take local hotwell level readings during implementation of Emergency Operating Procedure (EOP) Enclosure 5.9 steps 89 and 92. PIP proposed Corrective Action 1, stated "Determine if current staffing level is adequate for EOP requirements with the Unit 2 hotwell level erratic." The "Due date" for resolution of the issue was documented as July 27, 2006.

- Because the Unit 2 LPI pump room has a continuing problem with ground water intrusion, the room remains in a constant state of being posted as contaminated. The room being potentially contaminated limits room access for normal operation. This requires additional time to perform routine tours; however, time critical actions during event response are not affected, as donning of anti-contamination clothing is foregone.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed modification package OD500416, Remove Generator Lockout Function from K2 87GB-2 Relay, that changed the Keowee Unit 2 generator protective relaying scheme. This modification was reviewed to verify that the associated systems' design bases, licensing bases, and performance capability would be maintained following the modification; and that the modification would not leave the plant in an unsafe condition. The associated 10 CFR 50.59 screenings/evaluations were also reviewed for technical accuracy and to verify license amendments were not required.

b. Findings

No findings of significance were identified

1R19 Post-Maintenance Testing (PMT)

a. Inspection Scope

The inspectors reviewed PMT procedures and/or witnessed test activities, as appropriate, for selected risk significant systems to assess whether: (1) the effect of testing on the plant had been adequately addressed by control room and/or engineering personnel; (2) testing was adequate for the maintenance performed; (3) acceptance criteria were clear and adequately demonstrated operational readiness consistent with design and licensing basis documents; (4) test instrumentation had current calibrations, range, and accuracy consistent with the application; (5) tests were performed as written with applicable prerequisites satisfied; (6) jumpers installed or leads lifted were properly controlled; (7) test equipment was removed following testing; and (8) equipment was returned to the status required to perform its safety function. The inspectors observed testing and/or reviewed the results of the following six tests:

- PT/0/A/0250/025, HPSW Pump and Fire Protection Flow Test following preventive maintenance
- PT/2/A/0204/007, 2B Reactor Building Spray (RBS) Pump Test following train maintenance
- PT/1/A/0600/013, 1A Motor Driven Emergency Feedwater (MDEFW) Pump Test following pump lubrication
- PT/0/A/0251/010, Station ASW Pump Test following replacement of the rotating element
- PT/0/A/0400/015, SSF Submersible Pump Test following repairs to the pump's starter

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

Routine Surveillance

a. Inspection Scope

The inspectors witnessed surveillance tests and/or reviewed test data of the six risk-significant SSCs listed below, to assess, as appropriate, whether the SSCs met TS, the UFSAR, and licensee procedural requirements. In addition, the inspectors determined if the testing effectively demonstrated that the SSCs were ready and capable of performing their intended safety functions.

- PT/3/A/0600/012, Unit 3 TDEFW Pump Test (IST)
- IP/0/A/0305/14A, RPS CRD Breaker Trip and Events Recorder Timing Test (Unit 3 Only)
- PT/0/A/0600/021, SSF Diesel-Generator Operation
- TT/0/A/0400/033, SSF Sump Pump, Sump Pump Discharge Check Valve, and SSF Pump Room Water In-Leakage Test
- IP/0/B/0361/006, Encl 11.6.5, Sorrento Multichannel Area Radiation Monitors Calibration, completed for RIA-10, primary sample hood area radiation monitor.
- PT/1/A/0600/012, TDEFW Pump Test (IST)

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed documents and observed portions of the installation of selected temporary modifications. Among the documents reviewed were system design bases, the UFSAR, TS, system operability/availability evaluations, and the 10 CFR 50.59 screening. The inspectors observed, as appropriate, that the installation was consistent with the modification documents, was in accordance with the configuration control process, adequate procedures and changes were made, and post installation testing was adequate. The following item was reviewed under this inspection procedure:

- PIP O-06-1316, SSF Diesel Generator (DG) 87G Relay Test Jumpers (Modification OD500020)

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed and evaluated a simulator/plant based emergency preparedness drill held on January 25, 2006. The drill scenario involved a fire in the Unit 1 Equipment Room which eventually required activation of the SSF. The scenario progressed to a site area emergency when the SSF auxiliary feedwater system began feeding the steam generators. The operators were observed to determine if they properly classified the event and made the appropriate notifications for both the alert and site area emergency conditions. The inspectors observed the post drill critique to verify that the licensee captured any drill deficiencies or weaknesses.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors reviewed the circumstances related to the discovery by the licensee that a relatively large nut was left in the emergency sump suction of the Unit 2 B train LPI/RBS pumps. In particular, the inspectors reviewed this item to determine if unavailability hours associated with the B Train LPI pump were included in the Residual Heat Removal System PI reporting data. The inspectors reviewed PIP O-05-6829 that documented the discovery of the nut and other debris in the emergency sump on October 24, 2005, and other documentation which indicated that the nut would not transport from the emergency sump piping to the LPI pump.

b. Findings

During the Unit 2 Fall 2005 refueling outage, the licensee discovered debris in the containment emergency sump suction lines to the LPI/RBS pumps, including a relatively large nut in the B train suction line. Because of the design of the emergency sumps, the debris could only enter the lines during an outage when cover plates are removed from the sump. It was concluded that the debris was in the suction lines for at least one full operating cycle (June 15, 2004, to October 22, 2005).

In PIP O-05-6829, the licensee stated that “It is virtually certain that a nut that is transported by the fluid would settle into the disk guide rail cavity of this valve” (2LP-20, emergency sump suction valve). The licensee had calculated that the nut would likely be traveling at 5.5 ft/second. Additional calculations by a Region II Division of Reactor Safety (DRS) engineer indicated that the nut could be traveling at velocities greater than

5.5 ft/second. Based on the velocity of the nut in the LPI piping, the turbulence of the flow in the LPI piping, and the configuration and size of the valve guide, the NRC concluded that it would be very unlikely that the nut could be captured in the emergency sump suction isolation valve (2LP-20) and that the nut most likely would enter the 2B LPI pump suction and cause unacceptable pump damage. The Senior Reactor Analysis (SRA) noted in the Phase III evaluation that "Based on the weight and geometry of the hex nut, it was determined that there would only be sufficient flow during these conditions (large break and medium break LOCA [loss of coolant accident]) to transport the nut to the suction of the B pump, causing the pump to fail. The failure would not be recoverable."

The licensee's conclusion relied on engineering judgement and their belief that the nut would be captured by the valve guide. The inspectors, with support from Region II DRS and NRC headquarters, concluded that the licensee's analysis did not sufficiently represent the transport conditions that would be expected and that there were too many uncertainties to confidently predict that the nut would not transport to the 2B LPI pump. Based on this, it was concluded that reasonable assurance had not been provided to show that the 2B LPI pump would have remained available.

The inspectors concluded that the licensee's analysis did not provide an adequate basis to demonstrate that the 2B LPI pump would have remained functional during certain LOCA events with the nut in the emergency sump suction piping. Based on this, the inspectors determined that the hours in which the 2B LPI train was required to be available between June 15, 2004, and October 22, 2005, are considered to be fault exposure hours and should be added as unavailable time for the train. (See section 4OA5.4 of this report for additional details regarding this issue.)

4OA2 Identification and Resolution of Problems

.1 Daily Screening of Corrective Action Reports

As required by Inspection Procedure (IP) 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed daily screening of items entered into the licensee's corrective action program. This review was accomplished by reviewing copies of PIPs, attending daily screening meetings, and accessing the licensee's computerized database.

.2 Focused Review

a. Inspection Scope

The inspectors performed an in-depth review of an issue entered into the licensee's corrective action program. The sample was within the mitigating systems cornerstone and involved a risk significant system. The inspectors reviewed the actions taken to determine if the licensee had adequately addressed the following attributes:

- Complete, accurate and timely identification of the problem
- Evaluation and disposition of operability and reportability issues

- Consideration of previous failures, extent of condition, generic or common cause implications
- Prioritization and resolution of the issue commensurate with safety significance
- Identification of the root cause and contributing causes of the problem
- Identification and implementation of corrective actions commensurate with the safety significance of the issue.

The following issue and corrective actions were reviewed:

- Excessive Cycling of the Main Steam Relief Valves (MSRVs) during SSF-related events requiring the use of the SSF ASW System (PIP O-05-3770)

b. Findings

Introduction: A URI was identified for the failure to undertake adequate corrective actions to ensure that excessive cycling of the MSRVs during an event requiring the use of the SSF ASW System was minimized, thereby lowering the possibility of a MSRV failure. This issue is designated as a URI pending further inspection and assessment of the affect of excessive cycling on a MSRV during a SSF ASW-related event.

Description: On May 31, 2005, the licensee generated PIP O-05-3770, which documented MSRV operability concerns during certain SSF-related events. During an event that requires operation of the SSF ASW System, the two MSRVs with the lowest set pressure are required to lift and reseat as needed to remove decay heat from the reactor coolant system (RCS). PIP O-05-3770 documented the impact of an initial thermal-hydraulic analysis on the applicable MSRVs during the previously mentioned event. The PIP documents that, "Based on the inputs from the safety analysis group, the MSRVs could be expected to cycle open and closed approximately 990 times over a 72-hour period...If a single SG is fed, the corresponding MSRV may be cycled ...over 1600 cycles in 72 hours."

The licensee consulted with the MSRV manufacturer, Anderson Greenwood Crosby, "...to determine if the MSRVs are capable of performing their design basis function during an accident that requires operation of the SSF given the number of times that they must cycle open and closed. The manufacturer stated that, "...if the valve were subjected to this type of scenario, there would be a potential for seat leakage but there should be no concern structurally." This statement was based on testing performed on a different design AG Crosby MSRV (MSRV installed on BWR applications) where the valve was cycled approximately 200 times.

The inspectors reviewed the April 3, 1968 design specification for the MSRVs (OS-254), the main steam (MS) system DBD, and the Oconee UFSAR. However, no additional information supporting the ability of the valves to withstand this number of cycles was identified. In addition, the licensee was unable to provide any other information concerning the reliability of the MSRVs during any event in which the relief valves were required to cycle excessively. Consequently, the licensee's operability assessment documented in PIP O-05-3770 is based on the valve manufacturer's opinion and limited testing of a different designed valve.

The inspectors expressed their concerns to the licensee regarding the MSRVs' ability to be excessively cycled without failing, and the use of extremely limited test data on a relief valve designed for different operating conditions to justify operability and continued operation. On June 1, 2005, the licensee initiated two corrective actions related to this issue as documented in PIP O-05-3770. Corrective action (CA) #4 requested that the Duke General Office perform a refined thermal-hydraulic analysis to determine how many times the applicable MSRVs must cycle in an event requiring the use of the SSF ASW System. The refined analysis was assigned a completion date of June 20, 2005. CA #5 directed the creation of "...guidance for controlling MS pressure using the atmospheric dump valves [ADVs] during an SSF event, as desired, to limit MSRV cycling. It would direct MS pressure to be maintained below the MSRV lift setpoint but high enough to prevent RCS inventory problems." The creation of the guidance document was assigned an initial completion date of June 16, 2005.

On February 23, 2006, the licensee documented the completion of the refined thermal-hydraulic analysis in PIP O-05-3370. The refined analysis showed that the initial analysis was non-conservative, in that, the applicable MSRVs could be expected to cycle up to 2000 times during the 72-hour mission time of the SSF (as compared to the 1600 times calculated earlier).

Analysis: During an event requiring the use of the SSF ASW System, the MSRV with the lowest set pressure on each steam header could be expected to cycle open and closed up to 2000 times over the 72 hour mission time of the SSF. This could result in a failed MSRV; thereby, impacting the safety function of the SSF during accident scenarios that require the use of the SSF ASW System.

Enforcement: This issue remains unresolved pending further inspection and assessment to determine what impact excessive cycling of the MSRVs during a postulated event requiring the SSF ASW System may have had on the effected MSRV(s) and the Oconee unit requiring the operation of the SSF. On April 17, 2006, the licensee implemented operator guidance directing the utilization of the manually operated MS Atmospheric Dump Valves to limit the cycling of the MSRVs. As such, this finding does not represent an immediate safety concern. Accordingly, it will be identified as: URI 05000269,270,287/2006002-03, Survivability of Main Steam Relief Valves During an

Event Requiring SSF ASW System. This issue is in the licensee's corrective action program as PIP O-05-3770.

4OA3 Event Followup

(Closed) Licensee Event Report (LER) 05000287/2005-02-00, Unit 3 Reactor Trip With ES Actuation Due to Control Rod Drive (CRD) Modification Deficiencies. The inspectors' inspection activities and evaluation of this event are discussed in detail in NRC Special Inspection Report 050000287/2005010 and Section 4OA5.1 of this report. This LER is closed.

4OA5 Other Activities

.1 (Closed) Finding (FIN) 05000287/2005010-02, Inadequate Corrective Actions for an Identified Deficiency With the Unit 3 Digital Control Rod Drive System. This issue was discussed in detail (including corrective actions and the enforcement aspects) in NRC Inspection Report 05000269,270,287/2005010, and was left unresolved pending a Phase 3 risk evaluation. Subsequently, a regional Senior Reactor Analyst performed a Phase 3 risk evaluation of the issue and determined it to be of very low risk significance (Green). This was based primarily on the relatively low probability that the operators would fail to throttle or secure high pressure injection following the engineering safeguards actuation, coupled with a negligible human error rate dependance to subsequent operator actions for initiating high pressure recirculation. Accordingly, this finding is closed.

.2 (Closed) URI 05000269,270,287/2004004-03, Adequacy of Unit Vent Gaseous Effluent Sampling. This URI was previously inspected in NRC Inspection Report 05000269,270, 287/2005005. During that inspection, the inspectors identified non-cited violation (NCV) 05000269,270,287/2005005-03 for failure to ensure adequate measurements of particulate effluents released from the unit vent. Accordingly, this URI is administratively closed.

.3 NRC Office of Investigation (OI) Report Review

a. Inspection Scope

An in-office review of the results of an NRC OI report was performed. The review was conducted in order to determine if the findings of the report, regarding completeness and accuracy of the information contained in LER 05000287/2001-001 describing corrosion on the Reactor Pressure Vessel Head (RPVH), resulted in a violation of NRC requirements.

b. Findings

Introduction: The review identified a Severity Level IV NCV of 10 CFR 50.9 for failure to provide complete and accurate information in LER 05000287/2001-001, dated April 10, 2001.

Description: The NRC's requirements related to the submission of complete and accurate information are contained in 10 CFR 50.9, Completeness and Accuracy of Information. Specifically, Section 50.9(a) requires the licensee to submit and maintain information that is both accurate and complete in all material respects. On April 18, 2001, the licensee submitted LER 05000287/2001-001 concerning the discovery of RPVH leakage due to primary water stress corrosion cracking found in the control rod drive mechanism (CRDM) nozzle penetrations. The report stated that the small amount of boric acid deposits observed caused “no detectable corrosion” to the vessel head. The LER was compared to a slide presented by Duke Energy Corporation at an industry meeting, which contained information that conflicted with the description in the LER as to the condition of the RPVH. Contrary to the statement documented in the LER, the Duke presentation slide entitled “Corrosion/Erosion measurements on CRDM Nozzle #34," depicted corrosion up to ½ inch deep around the nozzle on the RPVH. The NRC Office of Investigations determined that the information in the LER was inaccurate. The investigation also concluded that the licensee’s actions in this regard were not willful. The review concluded that this information was material and inaccurate, in that minor corrosion due to boric acid was, in fact, found by the licensee’s staff on the Unit 3 RPVH during the Unit 3 refueling outage of 2001.

Analysis: Because this issue potentially affected the NRC’s ability to perform its regulatory function, it was evaluated using the traditional enforcement process. The failure to provide accurate and complete information precluded the NRC from being able to pursue or consider further inquiry or inspection activity in regards to RPVH corrosion, the significance of which was not known at the time. The NRC determined that the corrosion was not structurally significant and would not have resulted in a regulatory action or substantial further inquiry. Consequently, this failure was determined to be of very low safety significance.

Enforcement: The review determined that a violation of 10 CFR 50.9 occurred involving the submittal of incomplete and inaccurate information. 10 CFR 50.9 requires, in part, that “Information provided to the Commission by a licensee or information required by statute or by the Commission’s regulations, orders, or license conditions to be maintained by the licensee shall be complete and accurate in all material respects.” Contrary to the above, on April 18, 2001, LER 05000287/2001-001 was not complete and accurate in all material respects, in that the LER stated that the small amounts of boric acid crystal deposits observed around the CRDM Nozzles had caused no detectable corrosion to the vessel head, when in fact, minor corrosion was detected on the RPVH. Because this failure to provide the correct and accurate information is of very low safety significance, this violation is being treated as a Severity Level IV NCV consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000287/ 2006002-004, Failure to Provide Complete and Accurate Information to the NRC. The licensee took adequate corrective action and submitted a revision to LER 05000287/2001-001, dated August 18, 2005.

.4 (Closed) URI 05000270/2005005-02, Inadequate Foreign Material Exclusion Controls for the A and B Train Reactor Building Emergency Sump Suction Lines. This issue was discussed in detail in Inspection Report 05000269,270,287/2005005 and was left unresolved pending further inspection and assessment. Subsequently, a regional SRA performed a Significance Determination Process Phase 3 evaluation and concluded the finding was of very low safety significance (Green). The risk quantification was performed with the licensee’s full scope model and the NRC’s computerized model. The evaluation was based on an exposure time of at least one year, with foreign material inside of the B train suction line from the Unit 2 reactor building emergency sump (RBES) to the 2B LPI pump. Internal and external events that resulted in large or medium break

LOCA were the dominant accident sequences. Based on the weight and geometry of the hex nut it was determined that there would only be sufficient flow during these conditions to transport the nut to the suction of the B pump, causing the pump to fail. The failure would not be recoverable. Based on the initiating events and performance deficiency considered, there was no increase in large early relief frequency (LERF).

Because of the very low safety significance of this issue, because it has been entered into the licensee's corrective action program as PIP O-05-06829, and because it was identified by the licensee, this violation is being treated as a licensee identified NCV, which is documented in Section 4OA7 of this report.

4OA6 Management Meetings (Including Exit Meeting)

.1 Exit Meeting Summary

The inspectors presented the inspection results to Mr. Noel Clarkson, Acting Regulatory Compliance Manager, and other members of licensee management at the conclusion of the inspection on April 6, 2006. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Annual Assessment Meeting Summary

On April 24, the NRC's Acting Chief of Reactor Projects Branch 1 and the Resident Inspectors assigned to the Oconee Nuclear Station (ONS) met with Duke Energy Corporation to discuss the NRC's Reactor Oversight Process (ROP) and the NRC's annual assessment of ONS safety performance for the period of January 1, 2005 - December 31, 2005. The major topics addressed were: the NRC's assessment program and the results of the ONS assessment. This meeting was open to the public. A listing of meeting attendees and information presented during the meeting are available from the NRC's document system (ADAMS) as accession number ML061160182. ADAMS is accessible from the NRC Web site at *www.nrc.gov/reading-rm/adams.html*.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a NCV.

- The inspectors determined that there was a licensee identified violation of 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures and Drawings, which is implemented by NSD 104, Material Condition/Housekeeping, Cleanliness/ Foreign Material Exclusion and Seismic Concern, for the exclusion of foreign material from systems and components. The violation occurred because adequate material exclusion controls had not been implemented in the past, which allowed various debris to enter the Unit 2 reactor building emergency sump 2B LPI suction line. The risk significance and enforcement aspects of this issue were discussed in detail in Inspection Report 05000269,270,287/2005005 and Section 4OA5.4 of this report.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
N. Alchaar, Civil Engineering
L. Azzarello, Modification Engineering Manager
S. Batson, Superintendent of Operations
D. Baxter, Station Manager
R. Brown, Emergency Preparedness Manager
T. Bryant, Engineering Support
A. Burns, Civil Engineer, Reactor & Electrical Systems
S. Capps, Mechanical/Civil Engineering Manager
N. Constance, Operations Training Manager
D. Covar, Training Instructor
C. Curry, Maintenance Manager
G. Davenport, Compliance Manager
C. Eflin, Requalification Supervisor
P. Fowler, Access Services Manager, Duke Power
T. Gillespie, Reactor and Electrical Systems Manager
M. Glover, Engineering Manager
T. Grant, Engineering Supervisor, Reactor & Electrical Systems
R. Griffith, QA Manager
B. Hamilton, Site Vice President
R. Hester, Civil Engineer
D. Hubbard, Training Manager
T. King, Security Manager
T. Ledford, Engineering Supervisor, Reactor & Electrical Systems
L. Llibre, Engineering Supervisor
R. Murphy, Engineering Support
S. Neuman, Regulatory Compliance Group
L. Nicholson, Safety Assurance Manager
J. Rowell, Engineer, Reactor & Electrical Systems
J. Smith, Regulatory Affairs
B. Spear, Engineer, Reactor & Electrical Systems
J. Steeley, Training Supervisor
J. Stinson, Engineer, Reactor & Electrical Systems
P. Stovall, SRG Manager
F. Suchar, QC Supervisor
S. Townsend, Keowee Operations
J. Twiggs, Radiation Protection Manager
J. Weast, Regulatory Compliance

NRC
M. Ernstes, Chief of Reactor Projects Branch 1
L. Olshan, Project Manager, NRR

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000269,270,287/2006002-01	URI	Failure to Maintain Design Control of SSF Flood Protection Barrier (Section 1R06b.(1))
05000269,270,287/2006002-02	URI	Failure to Promptly Identify an Inadequate SSF Building Sewer System Design (Section 1R06b.(2))
05000269,270,287/2006002-03	URI	Survivability of Main Steam Relief Valves During an Event Requiring SSF ASW System (Section 4OA2.2)

Opened and Closed

05000287/2006002-004	NCV	Failure to Provide Complete and Accurate Information to the NRC (Section 4OA5.3)

Closed

05000287/2005-02-00	LER	Unit 3 Reactor Trip With ES Actuation Due to CRD Modification Deficiencies (Section 4OA3)
05000287/2005010-02	FIN	Inadequate Corrective Actions for an Identified Deficiency With the Unit 3 Digital Control Rod Drive System (Section 4OA5.1)
05000269,270,287/2004004-03	URI	Adequacy of Unit Vent Gaseous Effluent Sampling (Section 4OA5.2)
05000270/2005005-02	URI	Inadequate Foreign Material Exclusion Controls for the A and B Train Reactor Building Emergency Sump Suction Lines (Section 4OA5.4)

Items Discussed

none

DOCUMENTS REVIEWED

Section 1R04.2: Equipment Alignment

OP/1/A/1107/010, Operation of the Batteries and Battery Chargers
OP/1/A/1107/013, Removal and Restoration of Safety Related Motor Control Centers 1DCA and 1DCB
OP/1/A/1107/017, Removal and Restoration of Power Panelboards 1KVIA, 1KVIB, 1KVIC and 1KVID
Technical Specifications 3.8.1 and 3.8.3
Updated Final Safety Analysis Report Sections; 8.3.1, 8.3.2
Design Basis Specification, OSS-0254.00-00-2015, 120 VAC Vital Instrumentation and Control Power System
Design Basis Specification, OSS-0254.00-00-2006, 125 VDC Vital Instrumentation and Control Power System
Drawings; O-705, O-1705, O-2705

LIST OF ACRONYMS

ACB	-	Air Circuit Breaker
ADAMS	-	Agency wide Documents Access and Management System
ANSI	-	American National Standards Institute
ARM	-	Area Radiation Monitor
ATWS	-	Anticipated Transient Without SCRAM
AMSAC	-	ATWS Mitigation System Actuation Circuitry
AP	-	Abnormal Procedure
ASME	-	American Society of Mechanical Engineers
ASTM	-	American Society for Testing and Materials
ASW	-	Auxiliary Service Water
BMV	-	Bare Metal Visual
CAM	-	Continuous Airborne Monitor
CAP	-	Corrective Action Program
CC	-	Component Cooling
CCW	-	Condenser Circulating Water
CFR	-	Code of Federal Regulations
CRD	-	Control Rod Drive
CROABF	-	Control Room Outside Air Booster Fan
CTPD	-	Core Thermal Power Demand
DBD	-	Design Basis Document
DEC	-	Duke Energy Corporation
DG	-	Diesel Generator
DRS	-	Division of Reactor Safety
ECCS	-	Emergency Core Cooling
EDG	-	Emergency Diesel Generator
EHC	-	Electro-Hydraulic Control
EOC	-	End-of-Cycle
ES	-	Engineered Safeguards
FDW	-	Feedwater
FME	-	Foreign Material Exclusion
GPM	-	Gallons per Minute
HPI	-	High Pressure Injection
HPSW	-	High Pressure Service Water
HX	-	Heat Exchanger
ICS	-	Integrated Control
IP	-	Inspection Procedure
IR	-	Inspection Report
ISI	-	Inservice Inspection
IST	-	Inservice Testing
KHU	-	Keowee Hydroelectric Unit
kV	-	Kilo Volt
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
LOCA	-	Loss of Coolant Accident
LPI	-	Low Pressure Injection
LPSW	-	Low Pressure Service Water

MDEFW	-	Motor Driven Emergency Feedwater
MR	-	Maintenance Rule
MS	-	Main Steam
MSRV	-	Main Steam Relief Valve
MT	-	Magnetic Particle
NCV	-	Non-Cited Violation
NDE	-	Non-Destructive Examination
NIST	-	National Institute of Standards and Technology
NRC	-	Nuclear Regulatory Commission
NRMCA		National Ready Mixed Concrete Association
NRR	-	Nuclear Reactor Regulation
ODCM	-	Offsite Dose Calculation Manual
ONS	-	Oconee Nuclear Station
OOS	-	Out Of Service
ORAM	-	Operational Risk Assessment Monitor
OTSG	-	Once-Through Steam Generator
PARS	-	Publicly Available Records
PASS	-	Post Accident Sampling System
PCM	-	Personnel Contamination Monitor
PI	-	Performance Indicator
PIP	-	Problem Investigation Process report
PM	-	Preventive Maintenance
PMT	-	Post-Maintenance Testing
PRA	-	Probabilistic Risk Assessment
PT	-	Performance Test
PWHT	-	Post Weld Heat Treatment
QC	-	Quality Control
RBCU	-	Reactor Building Cooling Unit
RBES	-	Reactor Building Emergency Sump
RBS	-	Reactor Building Spray
RCMUP	-	Reactor Coolant Makeup Pump
RCA	-	Radiologically Controlled Area
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
REMP	-	Radiological Environmental Monitoring Program
RFO	-	Refueling Outage
RII	-	Region II
RP	-	Radiation Protection
RPV	-	Reactor Pressure Vessel
RPVH	-	Reactor Pressure Vessel Head
RTP	-	Rated Thermal Power
RV	-	Reactor Vessel
SCBA	-	Self-Contained Breathing Apparatus
SDP	-	Significance Determination Process
SGRP	-	Steam Generator Replacement Project
SLC	-	Selected Licensee Commitments
SRA	-	Senior Reactor Analyst
SSC	-	Structure, System, and Component

SSF	-	Standby Shutdown Facility
TDEFW	-	Turbine Driven Emergency Feedwater
TI	-	Temporary Instruction
TLD	-	Thermoluminescent Dosimetry
TS	-	Technical Specification
UFSAR	-	Updated Final Safety Analysis Report
URI	-	Unresolved Item
VDC	-	Volts-Direct Current
VAC	-	Volts-Alternating Current
WO	-	Work Order
WR	-	Work Request