UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

September 7, 2007

R. T. Ridenoure
Vice President
Omaha Public Power District
Fort Calhoun Station FC-2-4 Adm.
P.O. Box 550
Fort Calhoun, NE 68023-0550

SUBJECT: FORT CALHOUN STATION - NRC COMPONENT DESIGN BASES INSPECTION REPORT 05000285/2007007 AND NOTICE OF DEVIATION

Dear Mr. Ridenoure:

On July 25, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed a component design bases inspection at your Ft. Calhoun Station. The enclosed report documents our inspection findings. The findings were discussed via telecom on July 25, 2007, with Mr. Jeff Reinhart, Site Director, and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The team reviewed selected procedures and records, observed activities, and interviewed cognizant plant personnel.

Based on the results of this inspection, the NRC identified one Notice of Deviation from a license commitment, and five findings that were evaluated under the risk significance determination process. Violations were associated with the five findings. Each of the findings were found to have very low safety significance (Green) and the violations associated with these findings are being treated as noncited violations, consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest the Notice of Deviation, any of the noncited violations, or the significance of the violations you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC resident inspector at the Fort Calhoun Station.

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/

William B. Jones, Chief
Engineering Branch 1
Division of Reactor Safety

Dockets: 50-285
License: DPR-40

Enclosure:
Inspection Report 05000285/2007007
w/Attachments:
1. Supplemental Information
2. DC Transfer Switches
3. Diesel Generator Minimum DC Voltage for Field Flashing, June 12, 2007
4. Fort Calhoun Station Position on Emergency Diesel Generator Field Flash Voltage
5. Initial Information Request

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NOTICE OF DEVIATION

Omaha Public Power District
Fort Calhoun Station FC-2-4 Adm.
P.O. Box 550
Fort Calhoun, NE 68023-0550

Docket No. 50-285
License No. DPR-40

During an NRC inspection conducted from May 21 through July 25, 2007, a deviation of a commitment that Omaha Public Power District made in a September 6, 1979, letter to the U.S. Nuclear Regulatory Commission, was identified. In accordance with the NRC Enforcement Manual, the deviation is listed below:

> In the September 6, 1979, letter in support of the licensee's application for License Amendment 52, Fort Calhoun Station committed to "install temperature detectors, with readouts and alarms, in the control room to monitor safety injection pump room temperatures."
>
> Contrary to the above, the licensee did not install temperature detectors, with readouts and alarms, in the control room to monitor safety injection pump room temperatures, as stated in the September 6, 1979, letter. The deviation occurred on October 14, 1980, the date when License Amendment 52 was issued based, in part, on the modification to install temperature detectors. In addition, on November 1, 1999, after modifying operating procedures to restore ventilation to the safety injection pump rooms after an accident, the licensee did not notify the NRC that the commitment was never implemented.

Please provide a reply to this Notice of Deviation, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, Region IV, and a copy to the NRC Resident Inspector office at Fort Calhoun Station in writing within 30 days of the date of this Notice. The reply should be clearly marked as a "Reply to a Notice of Deviation;" and should include: (1) the reason for the deviation, or if contested, the basis for disputing the deviation; (2) the corrective steps that have been taken and the results achieved; (3) the corrective steps that will be taken to avoid further deviations; and (4) the date when your corrective action will be completed. Where good cause is shown, consideration will be given to extending the response time.

Dated this 7th day of September, 2007

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-285
License:	DPR-40
Report:	05000285/2007007
Licensee:	Omaha Public Power District
Facility:	Fort Calhoun Station
Location:	Fort Calhoun Station FC-2-4 Adm. P.O. Box 399, Highway 75 - North of Fort Calhoun Fort Calhoun, Nebraska
Dates:	May 14 through July 25, 2007
Team Leader:	R. Kopriva, Senior Reactor Inspector, Engineering Branch 1
Inspectors:	G. George, Reactor Inspector, Engineering Branch 1 J. Reynoso, Reactor Inspector, Engineeering Branch 1
Accompanying Personnel:	P. Wagner, Electrical Engineer, Beckman and Associates S. Speigelman, Mechanical Engineer, Beckman and Associates L. Ellershaw, PE, Consultant
Approved By:	William B. Jones, Chief Engineering Branch 1 Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000285/2007007; May 14 through July 25, 2007; Fort Calhoun Station; Component Design Basis Inspection.

The report covers an announced inspection by a team of three regional inspectors, and three contractors. Five findings and one deviation were identified. All of the findings were of very low safety significance. The final significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process 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. <u>NRC-Identified Findings</u>

Cornerstone: Mitigating Systems; Barrier Integrity

- <u>Green</u>. The team identified a noncited violation of Fort Calhoun Technical Specification 5.8, “Procedures,” for an inadequate Technical Specification required procedure. Specifically, Abnormal Operating Procedure 11, "Loss of Component Cooling Water,” could not be performed as written for establishing backup raw water to the containment fan coolers during post-accident conditions with a loss-of-component cooling water. The licensee has entered this finding into their corrective action program as Condition Report 2007-02268.

  The finding is greater than minor because it is associated with the barrier integrity cornerstone attribute for operating post event procedure quality. Using the significance determination process of Manual Chapter 0609, Appendix A, for the containment barrier cornerstone, the finding did not represent an actual open pathway in the physical integrity of reactor containment or involve an actual reduction of defense-in-depth for the atmospheric pressure control of the reactor containment. The finding had a cross-cutting aspect in the area of human performance resources (H.2.c) because the licensee did not ensure that procedures to assure nuclear safety, in this case establishing backup raw water to the containment fan coolers during post-accident conditions with a loss-of-component cooling water, were complete, accurate and up-to-date (Section 1R21.b.1).

- <u>Green</u>. The team identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion III, for the failure to perform a complete and adequate analysis of safety injection pump room temperatures to support operation of two high pressure safety injection pumps in one room during a design basis accident. The licensee performed the design calculation based on a limiting case with only one high pressure safety injection pump operating. However, at the operators discretion, the second high pressure safety injection pump could be started. The starting of the second high pressure safety injection pump in pump Room 21 would increase the room temperature to near equipment qualification temperature

limits. The licensee has entered this finding into their corrective action program as Condition Report 2007-02441.

This finding is more than minor because the engineering calculation results did not include a second high pressure safety injection pump running which would increase the temperature in pump Room 21 to near equipment qualification temperature limits. This unanalyzed condition raised reasonable doubt on the operability of the components within the room. Using the Manual Chapter 0609, Phase 1 screening worksheet, the issue screened as having very low safety significance because it was a design deficiency confirmed not to result in loss of operability in accordance with NRC Manual Chapter Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment (Section 1R21.b.2).

- Green. The team identified a noncited violation of 10CFR Part 50, Appendix B, Criterion III, for the failure to translate the Fort Calhoun Station raw water strainer component's design basis into specifications, procedures, and instructions. The raw water strainers are equipment necessary to ensure that nuclear safety functions provided by Safety Class 1, 2, or 3 equipment (raw water) are capable of accomplishing those functions. The licensee has entered this finding into their corrective action program as Condition Report 2007-3046.

  This finding is more than minor because it affected the mitigating system cornerstone objective (design control attribute) to ensure the reliability and capability of the raw water system to mitigate initiating events such that the raw water strainer function was necessary and relied upon for ensuring the nuclear safety functions that are provided by Safety Class 1, 2, or 3 equipment. Using Manual Chapter 0609, Phase 1 screening worksheet, the issue screened as having very low safety significance because it was a design or qualification deficiency confirmed not to result in a loss of operability per Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment (Section 1R21.b.3).

- Green. The team identified a noncited violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, for failure to promptly identify and correct conditions adverse to quality. Specifically, between November 11, 2005, to April 28, 2006, during quarterly surveillance tests of the steam bypass warmup valves for the turbine driven auxiliary feedwater pump, the licensee noted degrading conditions (change in flow coefficient, Cv) of the bypass warmup valves. During a postulated steam line break, the deteriorating bypass warmup valves could pass more steam than designed. Passing more steam through a pipe break would not maintain a mild environment to Room 19, where the auxiliary feedwater pumps are located, and, therefore would not ensure the operability of the safety-related equipment in the room. This issue was entered into the corrective action program as Condition Report 2007-2489.

  This issue was more than minor because the degrading throttle valve would have affected the ability to maintain a mild environment in Room 19 during a postulated steam line break as it pertained to the Mitigating Systems cornerstone

objective of equipment reliability associated with the motor-driven auxiliary feedwater pump. Using Manual Chapter 0609, Phase 1 screening worksheet, the issue screened as having very low safety significance, because it was a design or qualification deficiency confirmed not to result in a loss-of-safety function, in accordance with NRC Manual Chapter Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment. The finding had a cross-cutting aspect in the area of human performance decision making (H.1.b). The licensee had repeated opportunities to identify and correct the degrading bypass warmup valve but did not demonstrate conservative decision making to ensure the throttle valve differential pressure did not fall below established acceptance criteria (Section 1R21.b.4).

- Green. The team identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to meet the single valve failure requirements for the component cooling water surge tank. The component cooling water surge tank water and nitrogen supply lines were credited with only a single check valve for meeting single failure criteria requirements. Based on engineering review, this configuration is not considered acceptable. Manual Isolation Valves AC-1179 and NG-290 have now been administratively changed in accordance with the Safety Analysis for Operability from the normally open position to the normally closed position to meet the single failure criteria requirements for the component cooling water Surge Tank AC-2. Upstream Check Valves AC-391 and NG-113 were previously credited with meeting the single failure criteria. This issue was entered into the corrective action program as Condition Report 2007-2622.

  This finding is more than minor because it affected the mitigating system cornerstone objective (design control attribute) to ensure the reliability and capability of the equipment needed to mitigate initiating events. Using the Phase 1 worksheet in Manual Chapter 0609, "Significance Determination Process," this finding is determined to be of every low safety significance because there was no actual loss of a safety function (Section 1R21.b.5).

- Deviation. The team identified a Notice of Deviation for failure to install temperature monitoring of the safety injection pump room as committed to in a letter to the NRC, dated September 6, 1979. The commitment was submitted to support the licensee's application for License Amendment 52. During the inspector's review of other issues related with the safety injection pump room temperature, it was identified on June 6, 2007, that the temperature monitoring instrumentation was never installed, as committed in the 1979 letter. Since the proposed modification was never completed, the inspector concluded that the licensee failed to satisfy a written commitment, as documented in the September 6, 1979, letter. In addition, on November 1, 1999, after modifying operating procedures to restore ventilation to the safety injection pump rooms after an accident, the licensee missed an opportunity to notify the NRC that the commitment was never implemented. This issue was entered into the licensee's corrective action program as Condition Report 2007-0448.

The failure to install temperature monitoring is a performance deficiency because the licensee failed to satisfy a written commitment. This written commitment is not a legally binding requirement, as defined by the NRC Enforcement Manual. Since the performance deficiency is not legally binding, it will be treated as an administrative action with non-escalated enforcement action, consistent with Chapter 3 of the NRC Enforcement Manual. Since the licensee failed to satisfy a written commitment, this issue is being treated as a Notice of Deviation (DEV) consistent with Section VI.E of the NRC Enforcement Policy (Section 1R21.b.6).

REPORT DETAILS

1 REACTOR SAFETY

Inspection of component design bases verifies the initial design and subsequent modifications and provides monitoring of the capability of the selected components and operator actions to perform their design bases functions. As plants age, their design bases may be difficult to determine and important design features may be altered or disabled during modifications. The plant risk assessment model assumes the capability of safety systems and components to perform their intended safety function successfully. This inspectable area verifies aspects of the Initiating Events, Mitigating Systems and Barrier Integrity cornerstones for which there are no indicators to measure performance.

1R21 Component Design Bases Inspection (71111.21)

The team selected risk-significant components and operator actions for review using information contained in the licensee's probabilistic risk assessment. In general, this included components and operator actions that had a risk achievement worth factor greater than two or a Birnbaum value greater than 1E-6.

a. Inspection Scope

To verify that the selected components would function as required, the team reviewed design basis assumptions, calculations, and procedures. In some instances, the team performed calculations to independently verify the licensee's conclusions. The team also verified that the condition of the components was consistent with the design bases and that the tested capabilities met the required criteria.

The team reviewed maintenance work records, corrective action documents, and industry operating experience records to verify that licensee personnel considered degraded conditions and their impact on the components. For the review of operator actions, the team observed operators during simulator scenarios, as well as during simulated actions in the plant.

The team performed a margin assessment and detailed review of the selected risk-significant components to verify that the design bases have been correctly implemented and maintained. This design margin assessment considered original design issues, margin reductions because of modifications, and margin reductions identified as a result of material condition issues. Equipment reliability issues were also considered in the selection of components for detailed review. These included items such as failed performance test results; significant corrective actions; repeated maintenance; 10 CFR 50.65(a)1 status; operable, but degraded conditions; NRC resident inspector input of problem equipment; system health reports; industry operating experience; and licensee problem equipment lists. Consideration was also given to the uniqueness and complexity of the design, operating experience, and the available defense in-depth margins.

The inspection procedure requires a review of 15-20 risk-significant and low design margin components, 3-5 relatively high-risk operator actions, and 4-6 operating experience issues. The sample selection for this inspection was 20 components, 8 operator actions, and 5 operating experience issues.

The components selected for review were:

- 4160 circuit breakers
- Station batteries - including battery transfer switches
- Nitrogen admission to component cooling water surge tank, pressure control Valve PCV-2610
- Component cooling water shutdown heat exchanger inlet Valve HCV-480
- Safety injection and refueling water storage tank level indicators
- Raw water strainers
- Air accumulators - outside containment
- Safety injection pump room ventilation
- Reactor coolant pump seal coolant heat exchangers
- Turbine driven auxiliary feedwater governor
- High pressure core injection minimum flow recirculation isolation Valves HCV-385 and -386.
- Emergency diesel generator room ventilation
- Safety injection refueling water tank discharge Valves HCV 383-1, 2, 3, and 4
- Safety injection recirculation - through recirculation sump and safety injection refueling water tank
- High pressure core injection pump - net positive suction head and sequencing of valve manipulation (including safety injection refueling water tank vortex calculation needed to evaluate pump net positive suction head)
- High pressure core injection valve, motor-operated Valve HCV-312
- Raw water and component cooling water - interface
- Containment spray system - isolation Valves HCV-344 and -345.
- Control element assemblies

- Low pressure core injection - jockey pump
- Discharge side of component cooling water pressure control Switches 412 and 413

The risk significant operator actions included:

- Steam break outside containment
- Loss-of-auxiliary feedwater/loss-of-instrument air
- Station blackout/minimizing dc loads
- Loss of power
- Large break loss-of-coolant accident/loss-of-raw water
- Inter-system loss-of-coolant accident/outside containment loss-of-component cooling water
- Loss-of-turbine plant cooling water/loss-of-instrument air
- Potable water to air compressor

The operating experience issues were:

- Pressurizer power operated relief valve concerns
- Raw water underground piping
- Information Notice 1998-041,"Spurious Shut Down of Emergency Diesel Generators"
- Gas voiding of emergency core cooling systems
- Information Notice 2006-017, "Recent Operating Experience of Service Water Systems Due to External Conditions"

Unresolved item review for closure:

- Intake Structure Design, Unresolved Item 05000285/2005011-05
- Safety Status of Raw Water Strainer, Unresolved Item 05000285/2005009-01

b. Findings

b.1. Inadequate Abnormal Operating Procedure for Loss-of-Component Cooling Water

Introduction: The team identified a Green, noncited violation of Fort Calhoun Technical Specification 5.8, “Procedures,” for an inadequate Technical Specification required procedure. Specifically, Abnormal Operating Procedure 11, "Loss of Component Cooling Water,” could not be performed as written for establishing backup raw water to the containment fan coolers during post-accident conditions with a loss-of-component cooling water.

Description: The team reviewed condition reports and calculations related to Abnormal Operating Procedure 11, "Loss of Component Cooling Water." Abnormal Operating Procedure 11 is a recommended procedure in accordance with Regulatory Guide 1.33, "Quality Assurance Program Requirements." In 1994, the licensee concluded in Calculation FC05662, "Check of Back Pressure at Containment Air Cooling Coils," that with the maximum raw water flow to the containment air cooling coils and minimum river water level, the back pressure of the raw water system is insufficient to prevent flashing of the water in the containment air coolers under post-accident conditions in the containment. More recently, in July 2006, the licensee performed Calculation FC06621, "Containment Air Cooler Thermal Hydraulic Analysis for Accident with Loss-of-Offsite Power (LOOP)," which confirmed that the back pressure of the raw water system was insufficient to prevent flashing in the containment fan coolers under post-accident conditions. Therefore, aligning the raw water system to the containment fan would not be successful under all accident conditions as written in Abnormal Operating Procedure 11.

The team noted that after the condition was confirmed in July 2006, the licensee did not enter the condition into their corrective action program until October 2006, as documented in Condition Report 200604647. The action was to change all affected documents, including Abnormal Operating Procedure 11, by March 2007. As of April 2007, no changes had been made to the affected documents. Condition Report 200701130 was initiated to revise Abnormal Operating Procedure 11 by November 2007.

In June 2007, the team determined that no interim guidance had been provided to the operating crews during the time period in which Abnormal Operating Procedure 11 was being revised. In addition, the Team identified that operators were being trained on the continued use of the inadequate procedure during the revision period. The licensee subsequently notified the operators that certain steps of Abnormal Operating Procedure 11 could not be completed as written. The licensee has stopped training on the use of the procedure until the revision has been completed as identified in Condition Report 200701130.

Analysis: The failure to establish an abnormal operating procedure to address a loss of component cooling water to the containment fan coolers is a performance deficiency. The finding is greater than minor because it is associated with the barrier integrity cornerstone attribute for operating post event procedure quality. Using the significance determination process of Manual Chapter 0609, Appendix A, for the containment barrier

cornerstone, the finding did not represent an actual open pathway in the physical integrity of reactor containment or involve an actual reduction of defense-in-depth for the atmospheric pressure control of the reactor containment. The finding had a cross-cutting aspect in the area of human performance resources because the licensee did not ensure that procedures to assure nuclear safety, in this case establishing backup raw water to the containment fan coolers during post-accident conditions with a loss-of-component cooling water, were complete, accurate and up-to-date.

Enforcement: Fort Calhoun Technical Specification 5.8, “Procedures,” states, in part, that written procedures shall be established, implemented and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2. Item 6.i of Appendix A requires a procedure to combat a loss-of-component cooling system and cooling to individual components. Contrary to the above, Abnormal Operating Procedure 11, "Loss of Component Cooling Water,” could not be performed as written for establishing adequate backup raw water to the containment fan coolers during post-accident conditions with a loss-of-component cooling water. Specifically, inadequate back pressure of the raw water system could result in flashing of the raw water in the containment fan coolers when called upon during a loss-of-component cooling water condition. The team determined this issue to be of very low safety significance. Since this issue was entered into the licensee’s corrective action program as Condition Report 200702268, the finding is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000285/2007007-01, Inadequate Abnormal Operating Procedure for Loss-of-Component Cooling Water.

b.2. Failure to Analyze Impact of Heat Loading in Safety Injection Pump Room 21 from the Start of a Third High Pressure Safety Injection Pump

Introduction: The team identified a Green noncited violation of 10 CFR Part 50, Appendix B, Criterion III, for the failure to perform a complete and adequate analysis of safety injection pump room temperatures to support operation of 2 high pressure safety injection pumps in one room during a design basis accident. The licensee performed the design calculation based on a limiting case with only one high pressure safety injection pump operating. However, at the operators discretion, the second high pressure safety injection pump could be started.

Discussion: There are eight safety injection pumps divided into pump Rooms 21 and 22. In safety injection pump Room 21, there is one low pressure safety injection pump, one containment spray pump, and two high pressure safety injection pumps. In safety injection pump Room 22, there is one low pressure safety injection pump, two containment spray pumps, and one high pressure safety injection pump. The team reviewed the safety injection pump rooms’ ventilation analysis for a design basis accident. The rooms were reviewed because of the low temperature margin and high safety significance of the safety injection pumps. The maximum temperature of the rooms was analyzed in Calculation FC06747, Revision 3. The calculation assumes that there would be one high pressure safety injection pump, one low pressure safety injection pump, and one containment spray pump operating in each of the rooms. This assumption resulted from a 1999 design change that removed the automatic start feature for the third high pressure safety injection pump and third containment spray pump. The team found that adequate precautions were taken to restrict operation of one

of the two containment spray pumps in Room 22; but the second of the two high pressure safety injection pumps in Room 21 could be started at the operator’s discretion. The starting of the second high pressure safety injection pump would increase the room temperature to near the equipment qualification temperature limits.

In response to this finding, Condition Report 2007-02441 was issued and an operability evaluation was performed for the increased room heating that would result from starting a second high pressure safety injection pump in Room 21. The evaluation determined that the room temperature was slightly below the equipment qualification temperature limits with the second of the two high pressure safety injection pumps operating, and that the safety injection pumps in Room 21 would remain operable.

Analysis: The failure to meet design control requirements associated with the safety injection pump room temperature design was a performance deficiency. This finding is more than minor because the engineering calculation results did not include the operation of a second high pressure safety injection pump running which would increase the temperature in pump Room 21 to near equipment qualification temperature limits. This unanalyzed condition raised reasonable doubt on the operability of the components within the room. The team used Manual Chapter 0609, Phase 1 screening worksheet and determined that the finding was of very low safety significance because the finding is a design deficiency that did not result in the loss-of-safety function.

Enforcement: Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion III, "Design Control," requires, in part, that measures be established to provide for the verification of the adequacy of design. These measures may include calculations. The licensee used Calculation FC06747, Revision 3, to demonstrate the adequacy of the safety injection pump room temperature to assure the function of the safety injection pumps. Contrary to the above, as of September 2, 1999, the calculated design temperature limits control measures for safety injection pump Room 21 were non conservative, in that, Calculation FC06747 assumed that only one high pressure safety injection pump would be operating when it should have assumed that both high pressure safety injection pumps in safety injection pump Room 21 would be operating. The violation is of very low safety significance because it was a design deficiency confirmed not to result in loss-of-operability in accordance with NRC Manual Chapter Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment: NCV 05000285/2007007-02, Failure to Analyze Impact of Heat Loading in Safety Injection Pump Room 21 for the Start of a Second High Pressure Safety Injection Pump.

b.3. Use of Non Safety-Related Components in the Raw Water System Pump Discharge Strainers (Unresolved Item 05000285/2005009-01)

Introduction: The team identified a Green, noncited violation of 10CFR Part 50, Appendix B, Criterion III, for the failure to translate the Fort Calhoun Station raw water strainer component’s design basis into specifications, procedures, and instructions. The raw water strainers were incorrectly translated as non safety-related for their function of filtering small debris from the raw water system, although the equipment is relied upon to ensure the operation of the raw water system.

Description: The raw water system takes suction from the Missouri River, which is an open cycle cooling system and is the plant's ultimate heat sink. The river water comes into the intake structure through a series of traveling screens through three separate cells or bays. Four raw water pumps draw their suction from these cells. The pumps have cross-connected pump discharge headers, which discharge into one of two raw water strainers and then into the plant through a common header, to the component cooling water heat exchangers. The licensee established "screened river water" to mean water drawn through the intake structure traveling screens. Screened river water enters the cells or bays along with small gravel and debris, which collects near the raw water pump suctions. Upon starting the raw water pumps, this buildup of gravel and debris can be pumped into one of the two operating strainers. The strainers, which are continuously back washed, can become plugged. On several occasions this has resulted in complete blockage of one strainer and loss-of-cooling water in one header. The licensee's Design Basis Document SDBD-AC-RW-101 provides that the raw water strainers must be able to pass sufficient flow to meet the system flow requirements.

According to design basis calculations and vendor documents, rotation of the strainer is needed to ensure adequate back wash flow is available to remove entrapped debris from the screened water flow. The team noted that the licensee has not demonstrated that a degraded strainer would still meet its function and pass flow. Without proper strainer function or flow, the raw water system's capability to mitigate the consequences of an accidents is jeopardized. There have been several events over the last few years where changing river conditions have shown that a strainer can become clogged to such a degree that raw water flow is blocked in one header. River debris has clogged a raw water strainer resulting in the strainer motor tripping on current overload. The operators in the control room have no indication of a raw water strainer motor trip and rely on strainer differential pressure alarms or roving equipment operators to alert them of a tripped strainer motor. The team concluded that the raw water strainer is required to support the safety function of the raw water system and must be to screen out gravel and debris to maintain adequate cooling water flow to the component cooling water heat exchangers. Because this issue continues to be a concern at the Fort Calhoun Station, licensee management has placed the raw water strainer function under maintenance rule monitoring status in accordance with 10CFR 50.65 (A)(1).

The raw water strainer function was an original plant design feature that the licensee considered non safety-related. There is no mention of the raw water strainers or their filtering function in Fort Calhoun Station Updated Safety Analysis Report, Section 9.8. This section states only that the raw water pumps provide "screened river water" to the component cooling water heat exchangers. In a letter dated May 10,1988, "Safety Evaluation for Item 2.2 of Generic Letter 83-26," the NRC reviewed the licensee's response of criteria used to identify safety-related equipment and components. The licensee stated, "for mechanical criteria, the response identifies a special class which corresponds to a safety-Class 3 in ANSI NI8.2 and other components under ASME Section III Code." The licensee had classified the pressure boundary aspect of the raw water strainers as safety-related, but made no mention of the raw water strainer function or operability in their response or in the Updated Safety Analysis Report. Based on the licensee's review, the NRC concluded the licensee's response met the requirements and was acceptable.

In a letter dated November 16, 1992, the licensee provided the NRC a list of their implemented actions at Fort Calhoun Station to meet the recommendations of Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment. One of these actions was to establish a maintenance program for open-cycle service water system piping and components (including raw water components), such that, "corrosion, erosion . . . silting . . . cannot degrade the performance of safety-related systems supplied by service water." At Fort Calhoun Station, the service water system includes the component cooling water and raw water systems. Several modifications to the raw water system have been completed, but river debris, including small gravel, continue to impact the service water flow through the raw water strainers. Assumptions in the Fort Calhoun Station design basis calculation state that the raw water strainer must be in continuous operation, which means constantly back washing the strainer. The components required to maintain the strainer in continuous backwash were classified by the licensee as non safety-related (.i.e., strainer motor, backwash valve).

During the April 2005 Fort Calhoun Problem Identification and Resolution inspection, Unresolved Item 05000285/2005009-01 was issued. The team identified a concern with the classification of the raw water strainer motors and the straining function. The unresolved item was documented in Condition Report 2005-04740 with a response to the NRC dated May 19, 2005. In addressing this unresolved item, the licensee stated there had been one documented case of raw water header flow going to zero gallons per minute in year 2005 and two in 2006. Since then there have been seven more incidents of a strainer being plugged and blocking flow. The function of the raw water strainers is to remove debris to minimize fouling of the component cooling water heat exchanger and reduce maintenance. The licensee provided that the safety function of the raw water system can be achieved and maintained without the filtering function but in another case makes a conclusion that there are redundant strainer headers that provide sufficient margin to accommodate blockage. At the times when the raw water strainer was plugged, only one train became inoperable. The other strainer and train of raw water was always available. The team concluded that corrective actions have not been sufficient to prevent raw water strainer blockage and that the capability of raw water system to remain functional during and following design basis events has not been demonstrated.

The team discussed the safety classification of the raw water strainers with the NRC Division of Nuclear Reactor Regulation (NRR). In correspondence received from NRR dated June 25, 2007 a review of the safety classification of the raw water strainers was performed. Part of this assessment is provided below:

> According to the Fort Calhoun Station Updated Safety Analysis Report, Appendix N, Section 2.1, "The equipment assigned to Safety Class 1, 2, or 3 is that relied upon in the plant design to accomplish nuclear safety functions." Section 2.1.3 states, in part, that Safety Class 3 shall apply to equipment (not included in Safety Class 1 or 2) that is necessary to ensure that nuclear safety functions are able to be performed by Safety Class 1, 2, or 3 equipment (such as heat removal). The equipment in question, the raw water system strainers, fall into this category because they are necessary and relied upon for ensuring the nuclear safety functions that are provided by Safety Class 1, 2, or 3 equipment, such as

the capability to remove heat. Therefore, unless the licensee has specifically evaluated the capability of Safety Class 1, 2, and 3 equipment to perform their safety functions without relying on the raw water strainers and has conclusively demonstrated that the strainer function is not required for this purpose, the strainers should have been classified as safety-related (SC-3) in accordance with the Updated Safety Analysis Report criteria.

The team concluded the raw water strainer function was necessary and relied upon for ensuring the nuclear safety functions that are provided by Safety Class 1, 2, or 3 equipment to remain functional and that the strainers were required to be classified as Safety Class 3.

Analysis: The failure to correctly classify the raw water strainers as Class 3 to support the operation of the safety-related raw water system is a performance deficiency. This finding is more than minor because it affected the mitigating system cornerstone objective (design control attribute) to ensure the reliability and capability of the raw water system to mitigate initiating events such that the raw water strainer function was necessary and relied upon for ensuring the nuclear safety functions that are provided by Safety Class 1, 2, or 3 equipment. Using Manual Chapter 0609, Phase 1 screening worksheet, the issue screened as having very low safety significance because it was a design or qualification deficiency confirmed not to result in a loss of operability per Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment" The raw water system always had one train available, making the system operable.

Enforcement: Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, the licensee failed to correctly translate the applicable regulatory requirements and design basis to the raw water strainers to ensure the raw water system safety functions were able to be performed. This violation is being treated as a noncited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000285/2007007-03, Failure to Translate Regulatory Requirements and Design Basis to Equipment Required to Support the Raw Water System.

b.4. Inadequate Procedure for the Turbine Driven AFW (TDAFW) Keep Warm Line Bypass Throttle Valves MS-366 and 368

Introduction: The team identified a noncited violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, for failure to promptly identify and correct conditions adverse to quality. Specifically, between November 11, 2005, to April 28, 2006, during quarterly surveillance tests of the steam bypass warmup valves for the Turbine Driven Auxiliary Feedwater pump, the licensee noted degrading conditions (change in flow coefficient, Cv) of the bypass warmup valves. The bypass throttle valves are used to restrict steam flow to maintain the TDAFW 2-inch steam supply line warm, were in an "as-found" condition open beyond their acceptable range. In this condition, the valves were further open than assumed in the design basis calculations and a break in the 2-

inch steam line could allow more steam flow into Room 19 than what the room was analyzed for. This condition would have impacted the non environmentally qualified motor-driven auxiliary feedwater pump and, therefore, produced a condition in which both safety-related auxiliary feedwater pumps could not perform their safety-related function to mitigate design basis accident. This issue was entered into the corrective action program as Condition Report 2007-2489.

Description: The turbine driven and motor driven auxiliary feedwater pumps are located in Room 19. A 2-inch steam line transverses Room 19 and supplies driving steam to the TDAFW pump. The licensee has established a method to maintain the 2-inch steam supply line warm by using a small bypass line around the normally closed supply valves. This bypass line has a small valve which is throttled to setup a pressure drop across the valve. Design calculations established the throttle position which limit flow through the warm-up line. Bypass warmup Valves MS-366 and -368 are 1/2-inch throttle valves, on separate supply lines, which were installed to limit the release of steam in the event of a steam line break in the steam supply piping to the TDAFW Pump 10.

Part of the surveillance test performed on these valves is to check the throttle valve and record the differential pressure across the throttle valves. Surveillance Procedure OP-ST-AFW-0005, "Auxiliary Feedwater (AFW) Steam Supply Line Check," is performed quarterly in accordance with the Fort Calhoun Station Inservice Inspection Program. This surveillance procedure requirements are set to limit the release of steam in the event of a steam line break through the warmup line, assuring that the mild environment condition in the associated room, Room 19, is not exceeded. Room 19 also contains other safety-related equipment, such as the electric driven auxiliary feedwater pump, which has not been shown to operate in other than a mild environment.

The team noted that the licensee had not established effective surveillance test criteria to assure that the as left position of the adjustable throttle flow valves, used to restrict steam flow into Room 19, would not degrade and result in excessive steam leakage in the event of a steam line break before the conduct of the next surveillance. During quarterly surveillance tests between November 11, 2005, to April 28, 2006, the licensee noted degrading conditions (change in flow coefficient, Cv). This condition was evaluated under Condition Report 200601771 after the throttle valve could no longer be adjusted to obtain the proper differential pressure. The wear on the valves was determined to be minor. The team noted that the licensee had not adequately evaluated the condition of the valve until the throttle valve material condition had degraded and needed replacement. During the performance of the surveillance test, the "as-found" differential pressure across the throttle valves was less than the acceptance criteria range. On May 28, 2005, February 3 and April 28, 2006, the tests found that the differential pressures were less then 50 psi. The procedure permits an engineering evaluation of this condition. This evaluation, however, did not address the potential that the valve’s condition could have degraded beyond design basis conditions. Instead the valve was allowed to degrade to the extent that it was scheduled to be replaced during the next test. The valve internal clearances appear to have been degraded beyond the assumptions used to calculated steam flow and, therefore, outside design conditions. The team was concerned when the as-found differential pressure conditions had decreasing trends. The throttle valve had to be adjusted to ensure the as-left differential pressures were in the acceptable range. Warmup steam flow into the supply line is

based on the differential pressure across the throttle valve with a steam trap in service. Differential pressure is determined after the steam trap is isolated and the pressure is recorded. The team raised the concern with the licensee that a steam line break would result in conditions exceeding a mild environment. The licensee performed an operability determination and concluded that the auxiliary feedwater system remained operable because of expected operator actions to isolate header pressure during postulated events.

Analysis: The team determined that allowing the throttle valve differential pressure to fall below established acceptance criteria to ensure a mild environment in Room 19 during a postulated steam line break was a performance deficiency. This issue was more than minor because the degrading throttle valve would have affected the ability to maintain a mild environment in Room 19 during a postulated steam line break as it pertained to the Mitigating Systems cornerstone objective of equipment reliability associated with the motor-driven auxiliary feedwater pump. Using Manual Chapter 0609, Phase 1 screening worksheet, the issue screened as having very low safety significance, because it was a design or qualification deficiency confirmed not to result in a loss-of-safety function, in accordance with NRC Manual Chapter Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment. The finding had a cross-cutting aspect in the area of human performance decision making (H.1.b). The licensee had repeated opportunities to identify and correct the degrading bypass warmup valve but did not demonstrate conservative decision making to ensure the throttle valve differential pressure did not fall below established acceptance criteria

Enforcement: Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion XVI, Corrective Actions, requires, in part, that measures be established to assure conditions adverse to quality are promptly identified and corrected. Contrary to the above, Procedure OP-ST-AFW-0005 did not identify that the deteriorated bypass warmup valves would allow the throttle valve differential pressure to fall below established acceptance criteria, as required by the licensee's commitment to maintain a mild environment to Room 19 and, therefore, ensure the operability of the safety-related equipment in the room during a postulated steam line break. The acceptance criteria did not account for the as-found differential pressure throttle valves being in a condition that would challenge the assumptions made in the design basis calculations. The licensee was evaluating additional corrective actions, including possibly revising the test procedure. Because the violation was of very low safety significance and licensee personnel entered the finding into the corrective action program as Condition Report 2007-2489, this violation is being treated as a noncited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 2007007-04, Inadequate Corrective Actions for the Turbine Driven Auxiliary Feedwater Keep Warm Line Bypass Throttle Valves MS-366 and 368.

b.5. Component Cooling Surge Tank Nitrogen and Demineralized Water Supply Line Isolation Valves.

Introduction: The team identified a Green, noncited violation of 10 CFR Part 50, Appendix B, Criterion III. Since initial plant startup until June 23, 2007, the demineralized water and nitrogen makeup lines to the component cooling water surge tank did not comply with American National Standards Institute (ANSI) Standard 51.1, "Nuclear Safety Criteria for the Design of Pressurized Water Powerplants," with respect to single failure criteria (double isolation), as referenced in Updated Safety Analysis Report, Appendix N.

Description: The primary isolation points for the two makeup lines to the component cooling water surge tank were Check Valves AC-391 (demineralized water) and NG-113 (nitrogen gas). The lines from the surge tank to these isolation points are classified as CQE (safety-related). Everything upstream of these two valves is non CQE (non safety-related), including an additional check valve on each line.

The piping arrangement was not originally designed to facilitate in-service test leak testing of Check Valves AC-391 and NG-113. If either of the check valves failed the leak rate test, the entire component cooling water system would be inoperable, thus, placing the plant in Technical Specification 2.0.1 (immediate shutdown). This condition existed because there was no way to isolate the check valves in order to repair them (if needed), and depressurization of the surge tank would render the component cooling water system inoperable. The in-service leak test became a requirement circa 1994.

Maintenance Request 97-007 was created to deal with several issues, including installation of new manual isolation valves between the surge tank and Check Valves AC-391 and NG-113. Manual Valves AC-1179 and NG-290 would provide an alternate isolation point if the primary isolation points (the check valves) failed the leak test. The new manual valves can also be used to isolate the check valves from the surge tank if the check valves need repair. This would also make it less likely that the plant would have to enter Technical Specification 2.0.1 as a result of failure of the check valves to pass the surveillance test. Further, the maintenance request provided for relocating the existing check valves to a more convenient location, which would allow for easier operation and maintenance. The existing check valves were replaced with new check valves.

With respect to inservice testing, Check Valves NG-113 and AC-391 would remain in the in-service test program (Category A valves - specified maximum leak rates). The manual ball valves installed downstream of the check valves would be part of the safety-related pressure boundary, but would not be in the in-service test program because they function only as alternate backup isolation points if the corresponding check valve fails the leak test. These manual valves were in a normally open position.

On June 13, 2007, the team raised a question regarding double isolation requirements, and how was the licensee taking credit for the manual valves as isolation valves when they were in a normally open position. On June 14, 2007, the licensee initiated Condition Report 2007-2554 in response to the question. This led to the initiation of Condition Report 2007-2622, where the licensee performed an operability evaluation, dated June 21, 2007, Safety Analysis for Operability 07-002 and a 10 CFR 50.59 review, dated June 23, 2007.

The operability concern was the single failure criteria for the demineralized water and the nitrogen supply to the component cooling water surge Tank AC-2 was not being met. Updated Safety Analysis Report, Appendix N, "Reclassification of Systems," Section 1, is based on ANSI Standard N51.1, for boundary requirements and provides various configurations to meet single failure criteria. However, a single check valve does not meet the requirement for a safety Class 3 to non-class boundary. Having the manual valves in an open position caused the system to be inoperable (not in compliance). The licensee took steps to realign the two supply lines by closing the manual valves, thus, providing a double isolation arrangement. The 10 CFR 50.59 review determined that "During normal plant operations, the closed manual isolation valves meet single failure criteria and all other design requirements." During the limited time period when the manual isolation valves are open for tank maintenance activities (filling), the single failure criteria is not met since only a single CQE check valve (NG-113 or AC-391) provide the safety class boundary and pressure boundary function. It is not reasonably practicable to provide further CQE redundant components during this limited period of time. The single check valve will not fail by the initiating event it is required to protect against. The non-redundant check valve under the applicable plant conditions can meet the safety requirements while filling the tank. The reliability of the check valve is assured by its current testing in accordance with the in-service test Program. An operator would be available at the manual isolation valve providing the ability to recover from failure of the check valve in an adequate time frame. Other considerations which add reliability include the supply line pressure being higher than the tank pressure and the availability of the non-CQE PCV and LCV (upstream check valves) to close if a failure occurs.

"Based on review of PED-GEI-16 (Document 10, Section 5) and EPRI–6895 (Document 9, Section 7) Single Failure Analysis does not need to consider situations where one train (in this case one valve) is temporarily rendered inoperable due to short-term maintenance allowed by technical specifications. Based on this guidance, the proposed plant configuration is not a deviation from the guidance of ANSI N51-1 as referenced in Updated Safety Analysis Report Appendix N."

Prior to 1998, the licensee did not have a credible double isolation arrangement for the demineralized water and nitrogen makeup lines to the component cooling water surge tank as required by ANSI N51.1. In 1998, after installation of the manual valves in the safety-class portion of the system, they still did not comply with having a credible double isolation arrangement because the valves were in a normally open position. As shown in the 50.59 Applicability Determination, on June 23, 2007, the manual isolation valves were changed from the normally open position to the normally closed position to meet the single failure criteria for the component cooling water Surge Tank AC-2. While these valves are maintained in the closed position all requirements are met. It will be

necessary to periodically open these valves to add water and nitrogen to the surge tank. During the period of time these valves will be open, single failure criteria will not be met. This period of time is very short. An operator will be available at the manual valve(s) to close it during this period of time if required."

Additionally, the licensee created Operations Memorandum 2007-01, Revison 0, "Required Manual Actions to Make Additions to the component cooling water Surge Tank AC-2." This document provides the operating crews with manual methods to add deaerated water and nitrogen gas to the component cooling water Surge Tank AC-2. Further, there is a check list and signature/initial blocks for the operators to show compliance to the above guidance.

Analysis: The failure to comply with ANSI 51.1, "Nuclear Safety Criteria for the Design of Pressurized Water Powerplants," with respect to single failure criteria (double isolation) for the demineralized water and Nitrogen makeup lines to the Component Cooling Water (CCW) surge tank is a performance deficiency. This finding is more than minor because it affected the mitigating system cornerstone objective (design control attribute) to ensure the reliability and capability of the equipment needed to mitigate initiating events. Specifically, the failure of the check valves for the demineralize water and/or nitrogen supply to the component cooling water surge tank would have an adverse effect on the function and operability of the component cooling water surge tank. Using the Manual Chapter 0609, Phase 1 screening worksheet, the issue screened as having very low safety significance because it was a design deficiency confirmed not to result in loss-of-operability in accordance with NRC Manual Chapter Part 9900, Technical Guidance, *Operability Determination Process for Operability and Functional Assessment*.

Enforcement: Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion III, *Design Control*, requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in Part 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications drawings, procedures, and instructions. Also included are the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components. Contrary to the above, from initial operation of the plant until July 23, 2007, the licensee was not in compliance with Updated Safety Analysis Report Appendix N "Reclassification of Systems," Section 1, which is based on ANSI N51.1 for double isolation and boundary requirements for safety-related systems, or components, until such time as the manual valves were realigned to the normally closed position. Because the violation is of very low safety significance and has been entered into the licensee's corrective action program as Fort Calhoun Condition Report 2007-2622, this violation is being treated as a noncited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000285/2007007-05, Failure to Meet Single Failure Criteria Configuration for Component Isolation Valves.

b.6. Failure to Install Temperature Monitoring

Introduction: The inspector identified a Notice of Deviation for failure to install temperature monitoring of the safety injection pump room as committed to in a letter to the NRC, dated September 6, 1979.

Description: In a letter to the NRC, dated September 6, 1979, the licensee committed to installing remote temperature detectors with displays and alarms in the control room to monitor safety injection pump room temperature. The commitment was submitted to support the licensee's application for License Amendment 52. License Amendment 52 permitted the use of reduced air flow rates in the safety injection pump room; in addition, permitted the modification of associated technical specifications. To ensure safety injection pump room temperatures could be controlled under the safety injection pumps' maximum qualified temperatures, the licensee proposed, in the 1979 letter, to "install the temperature detectors, with readout and alarms, in the control room to monitor safety injection pump room temperatures."

During the inspector's review of other issues related with the safety injection pump room temperature, it was identified on June 6, 2007, that the temperature monitoring instrumentation was never installed as committed to in the 1979 letter. Further research, led inspectors to review the NRC Safety Evaluation Report to support License Amendment 52. The Safety Evaluation Report, dated October 14, 1980, states:

> "To further ensure the integrity of the ECCS (i.e. safety injection) pumps, the licensee is in the process of installing temperature detectors, with readout and alarms, in the control room to monitor safety injection pump room temperature. In the event that additional cooling is needed for the pump rooms, two actions can be taken. If activity levels are low enough, portable fans and blowers can be brought into the area. Otherwise, operator action can be taken from the control room to re-balance the ventilation system in order to provide increased cooling.
>
> "Based on our [NRC's] review of the licensee's submittals, we conclude that the safety injection pump room temperature has been adequately addressed and that the proposed technical specifications are acceptable."

Since the proposed modification was never completed, the team concluded that the licensee failed to satisfy a written commitment, as documented in the September 6, 1979, letter. In addition, based on the review of the Safety Evaluation Report, the team concluded that NRC's issuance of License Amendment 52 was based, in part, on the proposed installation of the temperature monitoring instrumentation.

Through further inspection, the team discovered that on November 1, 1999, the licensee made a procedure modification affecting emergency and abnormal operating procedures. The modification was to restore forced air flow, within 24 hours, to the safety injection pump rooms for equipment cooling in the event of safety injection actuation. Because of the modification to restore ventilation, the licensee made a decision to no longer adhere to the commitment for temperature monitoring

instrumentation. Although the licensee made the decision to not follow the commitment, the NRC was not notified of the decision.

Analysis: The failure to install temperature monitoring is a performance deficiency because the licensee failed to satisfy a written commitment. This written commitment is not a legally binding requirement, as defined by the NRC Enforcement Manual. Since the performance deficiency is not legally binding, it will be treated as an administrative action with non-escalated enforcement action, consistent with Chapter 3 of the NRC Enforcement Manual.

Enforcement: In the September 6, 1979, letter, Fort Calhoun Station committed to "install temperature detectors, with readouts and alarms, in the control room to monitor safety injection pump room temperatures." Contrary to the above, the licensee did not install temperature detectors, with readouts and alarms, in the control room to monitor safety injection pump room temperatures as stated in the September 6, 1979, letter. This deviation occurred on October 14, 1980, the date when License Amendment 52 was issued based, in part, on the modification to install temperature detectors.

During an inspection conducted on June 6, 2007, the team identified that the licensee had not made this modification to the plant although the NRC had approved the revision to the Technical Specifications on October 14, 1980.

The NRC's reliance on this modification was reflected in the NRC's Safety Evaluation Report dated October 14, 1980, which states, ". . . to further ensure the integrity of the ECCS (i.e. safety injection) pumps, the licensee is in the process of installing temperature detectors, with readout and alarms, in the control room to monitor safety injection pump room temperature. Based on our (NRC's) review of the licensee's submittals, we conclude that the safety injection pump room temperature has been adequately addressed and that the proposed Technical Specifications are acceptable."

This issue was entered into the licensee's corrective action program as Condition Report 2007-0448. Since the licensee failed to satisfy a written commitment, this issue is being treated as a Notice of Deviation(DEV) consistent with Section VI.E of the NRC Enforcement Policy: DEV 05000285/2007007-06, Failure to Install Temperature Monitoring.

b.7. Safety Injection Refueling Water Tank Vortexing

Introduction: The team identified an unresolved item concerning the safety injection refueling water tank. The issue concerns the minimum safety injection refueling water tank water level when the swap over to use containment sump recirculation occurs during a large break loss-of-coolant accident. An insufficient level at the time the swap over occurs could result in air entrainment from vortexing in the tank and losing net positive suction head of the pumps.

Description: The safety injection reactor water tank provides water to the safety injection pumps during the injection phase of a design basis accident. The tank was selected for inspection to determine if it has sufficient water to satisfy the Technical Specification requirements and to provide assurance that there would not be adverse impact on the

safety injection pumps due to insufficient net positive suction head or air entrainment. The team found the empty level of the tank was set at 16 inches, +0/-2 inches. The uncertainty calculation for the tank was +/- 1.25 inches which would be outside of the empty level. The licensee performed an operability assessment and determined that, based on the current instrument settings, that the tank remained operational.

Early in the inspection, the licensee's engineers stated that the question of vortex formation was earlier evaluated and it was determined by the licensee that the vortex eliminator would prevent the formation of the vortex. Condition Report 1998-00284 documented the evaluation results. The vortex eliminator is located at the entrance of the discharge pipe, however, the licensee did not have supporting calculations or test results to provide assurance that there would be no detrimental air entrainment during water discharge. The condition report was not acceptable because there was no supporting test or analytical evidence that the vortex eliminator would perform its function as expected. In lieu of such evidence, the NRC asked how the licensee would provide reasonable assurance that the minimum tank level was adequate. The condition report stated that the current industry methods of analysis were unreliable and that with the vortex eliminator there was no need for a vortex analysis. The team informed the licensee that without test data or an analysis available to support the function of the "vortex eliminator" then the team would have to consider that no vortex eliminator existed and that the licensee would have to determine the proper tank height to assure us that there were no vortices formed at the critical point of switching from the tank to the recirculation sump, and that the net positive suction head was always maintained. The licensee engaged a contractor to perform a test program to determine the acceptable minimum water height of the safety injection refueling water tank. The contractor performed a series of tests, and when questioned on the results from the first tests, elected to perform a second series of testing.

Following review of the results from the vortex testing, the team had additional questions concerning the testing results, test report and correlation that is being used to determine the design basis empty water level of the safety injection refueling water tank. This issue is unresolved pending further NRC review of such supporting documents (Unresolved Item 05000285/2007007-07).

Analysis: The NRC will complete a significance determination, if warranted, when closing out the unresolved item.

Enforcement: The NRC will consider enforcement, if necessary, when closing out the unresolved item.

b. 8. 4160 Volt Circuit Breakers

Inspection Scope

The team reviewed the electrical controls for the 4160 Volt safety-related circuit breakers to verify that the Updated Safety Analysis Report provisions were being properly implemented. The team reviewed electrical schematic and logic diagrams to verify that the control circuitry for selected circuit breakers incorporated the appropriate relay contact configurations to implement the required automatic actuations and the interlock

functions. The team checked the maintenance procedures for the circuit breakers to ensure the manufacturer's recommendations had been incorporated. The team reviewed the circuit breaker testing procedures to verify that the trip and interlock functions had been incorporated. The team also verified that adequate voltage would be available at the end of the station battery's coping cycle to operate the reviewed circuit breakers.

The team reviewed the offsite power systems and the interlocks provided to ensure the reliability of the two offsite supplies. The team evaluated the systems that were installed to provide protection from degraded grid voltage conditions to verify that those conditions would be detected and managed. The electrical schematics for the control circuitry were compared to the electrical distribution design information to verify proper implementation of the protective features. The team also reviewed the degraded voltage calculations to evaluate the adequacy of the determined voltage levels. The calculated voltage levels were utilized in the team's evaluation of selected motor-operated valves as discussed below. The team then reviewed the testing and calibration procedures for the degraded voltage and loss of voltage sensing relays to verify that the calculated values had been appropriately incorporated into the relay setpoints.

The team also evaluated the controls that were being implemented to ensure proper fuse control as part of the evaluation of fuse protection provided for the circuit breaker control circuitry. (Proper fuse application was also reviewed as part of the evaluation of other components during this inspection.)

b. Findings

No findings of significance were identified.

b.9. Station Batteries

a. Inspection Scope

The team evaluated the station batteries to ensure there was adequate capacity to fulfill the design provisions stated in the Updated Safety Analysis Report and other design commitments. The team reviewed the testing procedures to verify that the batteries were being adequately tested. The team also reviewed the dc voltage calculations to verify that sufficient voltage would be available at the terminals of selected loads to ensure their proper operation under end of cycle battery conditions. The team performed physical inspections of the installed batteries including the inter-cell connections and the inter-tier connection cables.

The team also reviewed a number of dc transfer switches that provide the capability for switching the power supply for selected components switched from one battery bus to the other. The team verified that the feeder cables routed to each transfer switch enclosure from each of the battery busses were protected by a Class 1E circuit breaker. The team also verified that those circuit breakers were being routinely tested. However, the team questioned the adequacy of the protection of the installations from fire damage. The transfer switches apparently had not been the subject of a detailed fire hazards analysis. The team reviewed available information and discussed these installations

with licensee personnel. The licensee's evaluation was presented to the team in the form of a position paper. A copy of the position paper is provided as Attachment 2.

The team reviewed the licensee's studies and calculations pertaining to the ability of the facility to cope with a station blackout. In addition to ensuring adequate voltage would be available to perform such functions as 4160 Volt circuit breaker actuations, the team also reviewed the capability to supply adequate voltage for emergency diesel generator field flash capability at the end of the four hour station blackout coping period. The team inspected the emergency diesel generator nameplate information and the manufacturers' technical manuals to locate any documented minimum voltage specification for emergency diesel generator field flashing. The licensee informed the team of their discussions on the aspects and considerations for emergency diesel generator field flashing with other facilities. The licensee's documented discussion concerning the ability to flash the emergency diesel generator field is provided as Attachment 3 to this input. The licensee's position on the ability to flash the Fort Calhoun Station emergency diesel generators' field is provided as Attachment 4 to this input.

The team reviewed the testing procedures and the results of recently completed battery capacity test to verify that the station batteries could perform the safety functions described in the Updated Final Safety Analysis Report. The team noted that the testing methodology and electrolyte temperature correction factors ('k') being used differed slightly from the methods and values provided in IEEE-450 Standard. Licensee personnel stated that the battery testing method and the 'k' factors had not been revised when Updated Final Safety Analysis Report commitments were revised to include the IEEE-450 Standard. The licensee initiated Condition Report 2007-2484 to revise the battery testing procedures to incorporate IEEE-450 Standard guidance.

As part of the station blackout reviews, the team included a review of the offsite power supply system to ensure that an instability on one of the systems (345 or 161 kV) would not result in the loss of the other system. The team also reviewed battery systems for both switch yards to verify that maintenance and testing was being conducted. The team performed inspections of both batteries to evaluate their physical condition.

b. Findings

No findings of significance were identified.

b.10. High Pressure Core Injection Motor-Operated Valve HCV-312

a. Inspection Scope

The team reviewed the schematic diagrams for Motor-Operated Valve HCV-312 to verify that the actuation and interlock functions discussed in design documentation were appropriately incorporated into the circuitry. The team reviewed the information collected by the licensee during their physical inspections of the motor-operated valve and its power supply system and verified that findings had been adequately addressed. The team included a review of the fuse program and verified that the fuse list specified the appropriate type and size of the fuses used in the control circuitry. The team also

verified that the motor's overload protection feature was bypassed except when the actuator was being tested.

As part of the evaluation of Valve HCV-312, the team reviewed the degraded voltage analysis and related motor-operated valve calculations to ensure that the actuator motor would be able to produce adequate torque at degraded voltage levels to operate the valve.

b. Findings

No findings of significance were identified.

4 OTHER ACTIVITIES

4OA3 Event Followup

(Closed) Unresolved Item 05000285/2005-009-01 Use of non safety-related components in the raw water system pump discharge strainers. This issue is addressed in Section 1R21.b.3 of this report.

4OA5 Other

(Closed) Use of Non Safety-Related Components in the Raw Water System Pump Discharge Strainers (Unresolved Item 05000285/2005009-01)

This unresolved item is discussed in Section 1R21.b.3 of this report and closed to Finding 05000285/2007007-03, NCV-Failure to Translate Regulatory Requirements and Design Basis to Equipment Required to Support the Raw Water System.

4OA6 Meetings, Including Exit

On July 25, 2007, the team leader presented the preliminary inspection results to Mr. Jeff Reinhart, Site Director, and other members of the licensee's staff. The licensee acknowledged the findings during each meeting. On September 7, 2007, the team leader discussed the inspection results with Mr. Matzke. While some proprietary information was reviewed during this inspection, no proprietary information was included in this report.

Attachments:
1. Supplemental Information
2. DC Transfer Switches
3. Diesel Generator Minimum DC Voltage for Field Flashing, June 12, 2007
4. FCS Position on emergency diesel generator Field Flash Voltage
5. Initial Information Request

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

S. Anderson, Supervisor, DEN - Mechanical
S. Baughn, Supervisor, Reactor Performance Analysis
D. Bannister, Plant Manager
G. Cavanaugh, Supervisor, Regulatory Compliance
R. Clemens, Division Manager, Nuclear Engineering Division
M. Core, Manager, System Engineering
H. Faulhaber, Division Manager, Nuclear Asset Management
M. Ferm, Manager, Shift Operations
M. Frans, Manager, Quality
D. Guinn, Licensing Engineer
J. Herman, Manager, Engineering Programs
J. Jacobsen, Design Engineering
J. Johnson, ECC Systems Engineer
D. Lakin, Manager, Corrective Action Program
T. Matthews, Supervisor, Nuclear Licensing
E. Matzke, Compliance Engineer
J. McManis, Manager, Licensing
D. Pier, Operation Engineering - Operations
S. Miller, Supervisor, System Engineering
R. Mueller, Supervisor, Electrical / I&C Engineering
M. Puckett, Work Management
J. Reinhart, Site Manager
J. Skiles, Manager, Design Engineering
C. Sterba, Supervisor, Design Engineering
S. Swearngin, Supervisor, Design Engineering - Mechanical
D. Taylor, Engineering, Design Engineering - Mechanical
R. Westcott, Manager, Quality
J. Zagata, Engineering Programs

NRC personnel

D. Powers, Acting Branch Chief, Engineering Branch 1
L. Willoughby, Acting Senior Resident Inspector

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000285/2007007-01	NCV	Inadequate Abnormal Operating Procedure for Loss-of-Component Cooling Water(Section 1R21.b.1)

05000285/2007007-02	NCV	Failure to Analyze Impact of Heat Loading in Safety Injection Pump Room 21 from the Start of a Third High Pressure Safety Injection Pump(Section 1R21.b.2)
05000285/2007007-03	NCV	Failure to Translate Regulatory Requirements and Design Basis to Equipment Required to Support the Raw Water System - Unresolved Item 05000285/2005009-01 (Section 1R21.b.3)
05000285/2007007-04	NCV	Inadequate Corrective Actions for the Turbine Driven Auxiliary Feedwater Keep Warm Line Bypass Throttle Valves MS-366 and -368(Section 1R21.b.4)
05000285/2007007-05	NCV	Failure to Meet Single Failure Criteria Configuration for Component Isolation Valves (Section 1R21.b.5)
05000285/2007007-06	DEV	Failure to Install Temperature Monitoring (Section 1R21.b.6)

Opened

05000285/2007007-07	URI	Safety Injection Refueling Water Tank Vortexing (Section 1R21.b.7)

Closed

05000285/2005-009-01	URI	Use of Non-safety-related Components in the Raw Water System Pump Discharge Strainers (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

Action Requests

199701532	200502017	200600613	200701942
199800284	200502771	200600630	200702013
199802335	200502867	200600860	200702208
199902722	200503018	200601319	200702268
200000127	200503169	200603222	200702270
200001220	200503746	200604605	200702281
200103349	200504001	200604647	200702304
200201089	200504287	200604756	200702309
200201182	200504287	200604989	200702381
200201930	200504328	200605139	200702470
200302653	200504346	200605663	200702489
200302694	200504740	200605721	200702533
200304924	200505027	200605723	200702753
200400846	200505030	200606038	200702917
200401345	200505207	200700613	
200501228	200505795	200700662	
200501804	200505897	200700892	
200501955	200600508	200701130	

Calculations

Number	Title	Revision/Date
FC-05038	Evaluation of Stroke Time on Valves HCV-480, -481, -482, -483, -484, -485	2 (11/22/06)
FC-05872	HPSI Header Isolation MOVs (HCV-311, -314, -317, -320, and HCV-312, -315, -318, and -321)	0 (2/13/92)
FC-05455	ECCS Pump NPSH and 383-Series Valve Stroke Times	0
FC-85-25-003	Ampacity Derating to be Applied Due to Fire Wrapping	02/04/86
FC-90-057	Updated Degraded Voltage Calc 4160V/480V	7
FC-03-026	Period[ic] Evaluation of the Offsite Power Requirements	1
FC04990	Feeder Cable Derating Due to Fire Wrapping	12/27/91
FC05690	Battery Load Profile and Voltage Drop Calculation	6
FC05829	MOV Degraded Voltage Calculation	10
FC05876	Analysis of MOV Torque/Thrust	15
FC06096	[MOV} Contactor Pickup and Holding Voltage	6
FCO5455	ECCS Pump NPSH and 383 Series Valve Stroke Times	3
FC05384	Min Performance Curves for HPSI, LPSI and CS	1
FC07076	Safety Injection and Containment Spray System, Proto Flow, Model Development	8
FC07077	Safety Injection Phase performance for Containment Spray and safety injection Pumps,	1
FC070078	circulation Phase Plant System Performance forSafety Injection and Containment Spray Systems	1
FC05384	Minimum Pump Performance Curves for HPSI, LPSI and CS Pumps	1
FC08839	Containment Minimum Performance Requirements	2

FC06642,	Uncertainty Calculations to support ISI Testing,	2
	HPSI Safety Injection Phase Performance for Safety Injection Containment Spray Systems	1
FC06747	safety injection Pump Room (21 and 22) Heat-up during pump operation, Computer Analysis	3
FC06941	LPSI Critical Void Size and Operator Action Time	1
FC06904	Category 1 Air Operated Valve Operator Margin Analysis	2
FC05876	Evaluation of MOV Degraded Voltage, NED-DEN-06-0087	0
FC00284	Variable Setpoints for PORV Actuation	0
FC05038	Evaluation of Stroke Time on Valves on HCV-480, 481-483, 485	2
FC05561	CCW Relief Valve Setpoints	2
FC05692	Minimum NPSHA Calculation for CCW Pumps	3
FC05729	High Pressurizer Pressure Setpoint Calculation	1
FC06156	PORV Loop Seal Condensation Flow Rate	0
FC06227	Post-RAS Containment Heat Removal by Shutdown Cooling Heat Exchangers and Containment Air Coolers	1
FC06621	Containment Air Cooler Thermal Hydraulic Analysis for Accident with LOOP	1
FC06700	NPSH for Single Operation CCW Pump	0
EA-96-055	Overpressurization of CCW System	0
FC07217	Fort Calhoun Element Drive Mechanism Component Cooling Water Supply Flow Rates	0
FC06604	Bearing Cooling Water Flow Balance	B
FC-05045	FW-10 Steam Line HELB	1

MR-FC-89-81	FW-10 Steam Supply Line Break Protection, throttle valves recommended.	2/4/1992
EA-FC-92-030	Seismic Classification of SER system	4/22/1992
FC-03109	Auxiliary Feedwater Seismic calculations	1/22/1985
FC-06174	Required Coping Duration for Station Blackout	2/28/2000
EA-FC-03-004	Long Term Core Cooling Verification	0
EA-FC-89-023	Electrical Equipment Qualification analysis	2
FC-05928	SIRW Tank Level (RAS)	6/19/1992
FC-05659	Development of Flow Coefficients for the Raw Water and CCW system analysis.	1
FC-05888	Raw Water Flows to the CCW heat exchangers	1
FC-06273	Raw water flows to CCW HEX based on pump performance	0
FC-01438	Air Accumulator Capacity for IA-41	1
FC-04280	Verification of Air Accumulator bubbler Flowrates	0
FC-06277	SIRWT Level Indication Total Loop Uncertainty (TLU) Calculation	2
FC-06679	Raw Water Strainer Resistance for Winter River Temperatures	0
AC-12A SEWS	Screening Evaluation Work Sheet, Motor driven Strainer Seismic capacity vs demand	10/21/1994
FC-07259	FCS RW/CCW GOTHIC model- cases	8

Design Bases Documents

Number	Title	Revision/Date
SDBD-AC-RW-101	Raw Water	30
SDBD-CA-IA-105	Instrument Air	26

SDBD-AC-CCW-100	Component Cooling Water	38
MR-FC-97-007	Final Design Issue	0
SDBD-AC-RW-101	Raw Water Design Basis Document	30
PED-FC-92-1827	MR-FC-89-081 "FW-10 Steam Supply line Break Protection	2/4/1992.
EA-FC-96-042	HELB Steam Migration From Room 81 via Ductwork	11/21/1996
SDBD-AC-CCW-100	Component Cooling Water Design Basis Document	37
SDBD-AC-RW-101	Raw Water Design Basis Document	28
SDBD FW-AFW-117	Auxiliary Feedwater Design Basis Document	32
USAR-9.7	Auxiliary Systems Component Cooling Water System	8
USAR-9.8	Auxiliary Systems Raw Water System	15
LER-92-0530	GL 89-13, Service Water System Problems	11/16/1992
TBD-VIII	Technical Data Book, Equipment Operability Guidance	30

Drawings

Number	Title	Revision/Date
11405-M-100	Raw Water Flow Diagram P&ID	91
11405-M-40, Sh 1	Auxiliary Coolant Component Cooling System Flow Diagram P&ID	36
E-23866-210-130, Sh 3	Safety Injection and Containment Spray Flow Diagram P&ID	16
Spec No. 16.04, Rev Sh 21864	Sheet Electric Motor Operated Valves	2
Spec No. 55S2372A-1 Rev Sh 36188,	Sheet Streamless Butterfly Valves, Allis Chalmers	5

2498-20-5-20,	" Wafer Style Butterfly Valve 150# Class with Bettis T-316 Actuator	C
Spec No 11.87,	Sheet Safety Injection System Control Valves	8273, 19
E-23866-210-130, .	Sheet Cov., Composite Flow Diagram SI and CS Sys P&ID	39
E-23866-210-130. ,	Sheet 1, Safety Inj. And Cont. Spraiy Sys Flow Diagram	89
12702, 35759,,	Safety Injection Aux Bldg (SI) (Isometric Drawing)	11
11450-M-97	Sheet 2. Misc. HVAC Flow Diagram	5
A-6282	SIRWT Vortex Arrestors	0
11405-M-87	Auxiliary Building Ventilation El 989', 0" Fuel Handling Area	9
11405-M-45,	Auxiliary Building Ventilation, Sections and Details,	18
11045-M-2 Sh 1	Auxiliary Building Heating and Ventilation Flow Diagram P&ID	57
11045-M-97 Sh2	Misc HVAC Flow Diagram P&ID	5
EM-871 Sh2	I&C Equipment List (Damper Drawing)	17
11045-M-84	Aux Building Ventilation 971', 0" (SI Room)	14
35617	SI Isometric IC-70-A&C-SITs	10
35618	SI Isometric IC-71 B&D SIT	10
35619	SI Isometric IC-72 HCV 331 and 333	13
35759	SI Piping Isometric	7/28/70
35620	SI Isometric IC-73 HCV 329	9
35621	SI Isometric IC-74 HCV 327	10
35622	SI Isometric IC-75	10

35623	SI Isometric IC-76,	8
35624	SI Isometric IC-77 HVC 327	9
35625	SI Isometric IC-79 HVC 329 & 333	10
34627	SI Isometric IC-80 HVC 331	9
23423	ISI Isometric, SWIRT and Sump exit Piping	8
B120F11503, Sh. 1	EDG Electrical Control Schematic	19
B120F11503, Sh. 2	EDG Electrical Panels Layout	21
B120F11503, Sh. 1	EDG Electrical Control Connections	13
B120F14501, Sh. 1	EDG Engine Control Schematic	6
B120F15502, Sh. 1	EDG AC and DC Distribution Panels	10
B120F15502, Sh. 2	EDG AC and DC Distribution Panels	10
B120F15503, Sh. 1	EDG Electrical Control Cabinets	19
B120F15503, Sh. 2	EDG Electrical Control Cabinets	21
B120F15503, Sh. 3	EDG Control Cabinets Full Line Diagram	13
B120F15509, Sh. 3	EDG Field Flashing and Remote Start Control	21
B-4280, Sh. 1	Limit Switch and 43/SW Contact Development	2
D-841	C&D Power Systems Discharge Characteristics	1
D-4097, Sh. 1	CCW Low Pressure Schematic Diagram	7
D-4097, Sh. 6	CCW Low Pressure Schematic Diagram	5
D-4665	DG-1 Diesel Generator Connections One Line Diagram	5
D-4666	DG-2 Diesel Generator Connections One Line Diagram	5
E-3335-1	Substation No. 1251/3451 One Line Diagram	10

E-3335-2	Substation No. 1251/3451 One Line Diagram	11
E-4027, Sh. 1	Off-Site Power Low voltage Matrix A & B	13
44D302335	Full Wave Static Exciter	6
0223R0455, Sh. 4	Bus 1A3 Lockout Circuit Schematic Diagram	3
0223R0455, Sh. 6	Bus 1A3 Power & Control Circuit Schematic	3
0223R0455, Sh. 10	Power & Control Schematic for EDG #1CB	7
0223R0456, Sh. 8	Power & Control Schematic for EDG #2 CB	12
0223R0456, Sh. 23	Power & Control Schematic for 480 Bus Feeder CB	8
0223R0456, Sh. 26	Power & Control Schematic for RCP 3D CB	Rev. 8
136B2432, Sh. 6	4160 Volt Circuit Breaker Control Switch Development	18
136B2493, Sh. 3H	Electrical Controls - PCS 412 & 413	0
136B2493, Sh. 65	Elementary Diagram - PCS 412	23
136B2493, Sh. 66	Elementary Diagram - PCS 413	2
136B2493, Sh. 115	Elementary Diagram - PCS 412	4
136B2493, Sh. 116	Elementary Diagram - PCS 413	4
161F532, Sh. 2	Main Breaker Control Schematic Diagram - 4.16 kV	30
161F532, Sh. 3	Main Breaker Control Schematic Diagram - 4.16 kV	32
161F532, Sh. 3A	Main Breaker Control Schematic Diagram - 4.16 kV	29
161F532, Sh. 5	Main Breaker Control Schematic Diagram - 4.16 kV	27
161F532, Sh. 7	Main Breaker Control Schematic Diagram - 4.16 kV	28

161F532, Sh. 10	Main Breaker Control Schematic Diagram - 4.16 kV	28
161F532, Sh. 13	Main Breaker Control Schematic Diagram - 4.16 kV	29
161F532, Sh. 17	Main Breaker Control Schematic Diagram - 4.16 kV	29
1111317	Internal Circuit Breaker Schematic	2
11405-E-1	4.16 kV Control Relay Connection Diagram	43
11405-E-3	4.16 kV One Line Diagram	21
11405-E-4, Sh. 1	480 Volt MCC One Line Diagram	30
11405-E-5, Sh. 2	480 Volt MCC One Line Diagram	29
11405-E-6, Sh. 1	480 Volt MCC One Line Diagram	71
11405-E-7, Sh. 1	480 Volt MCC One Line Diagram	54
11405-E-29, Sh. 3	SI Valves Schematic Diagram	26
11405-E-29, Sh. 11	Limitorque Valve Schematic - HCV-312	8
11405-E-360, Sh. 7	DC Power Transfer Switches Control Schematics	1
120-12776	AI-133A & 133B [EDG Control Panels] Material List	19
35759	SI Piping Isometric	07/28/70
11405-M-10, Sh. 2	Auxiliary Coolant Component Cooling System Flow Diagram	14
11405-M-42, Sh. 1	Nitrogen, Hydrogen, Methane, Propane, and Oxygen Gas Flow Diagram	90
11405-M-5, Sh. 2	Demineralized Water System Flow Diagram	22
2374	AC-2 Comp. Cooling Water Surge	1
136B2431, Sh. 26	Electrical Diagram Electrical Control Valves & Pumps	30

136B2431, Sh. 3	Electrical Control Valves and Pumps	5
B-4250, Sh. 285	Cable Block Diagram, HCV-485	0
B-4250, Sh. 282	Cable Block Diagram, HCV-480	1
303.165-M-01	HCV-480/481 Instrument Air Upgrade	2
303.165-M-01	HCV-480/481 Instrument Air Upgrade	2
B-4250, Sh. 283	Cable Block Diagram HCV-481	1
136B2431, Sh. 2	Electrical Control Valves and Pumps Elementary Diagram	13
136B2431, Sh. 25	Electrical Diagram Electrical Control Valves and Pumps	29
11405-E-56, Sh. 8	Auxiliary Coolant System Wiring Diagram	21
11405-E-148, Sh. 2	Schematic, Auxiliary Cooling System	10
D-4097, Sh 6.	AC Raw Water Interface Valves – Secondary Solenoid Valves and Pressure Switches Wiring Diagrams	5
136B2493, Sh. 65	Electrical Control Valves and Pumps Elementary Diagram	23
136B2493, Sh. 3H	Electrical Control Valves & Pumps	0
28308	Governor FW-10 Emergency Feedwater pump	4
01128	Governor Gear Box and Oil pump	A
11405-M-252	Flow Diagram Steam P&ID	98
11405-E-137	Wiring Diagram YCV-1045 FW-10	26
11405-M-100	Raw Water Flow Diagram	91
11405-M-254	Flow Diagram Condensate P&ID	35
NOD-Qp-31	Operability Determination Process	34
PED-SEI-9	Setpoint/tolerance Change and Review	12
OI-RW-1	Raw Water System Normal Operation	78

STM 35	System Training Manual Vol 35, Raw Water	21
STM 4	System Training Manual Vol 4, Auxiliary Feedwater system	35
STM 8	System Training Manual Vol8, Component Cooling Water System	27
E-23866-210-130	Safety Injection and Containment Spray P&ID	39

Engineering Change

Number	Title	Revision/Date
EC 27584	Isolation of Flow to Containment Coolers on Flow Interruption	0
MR-FC-92-039	RW/CCW Interface Valve Modification	3
MR-FC-97-007	Correction of CCW System Deficiencies	0

Maintenance Document

Number	Title	Revision/Date
00177675	Underground RW Piping Internal Inspection	01
00266504	AC-1D, Performance Monitoring Test for CCW HX	01
00265456	AC-1C, Performance Monitoring Test for CCW HX	01
00265455	AC-1B, Performance Monitoring Test for CCW HX	01
00252620 01	AFW pump FW-10 Operability Test	01/25/07
253665 01	Instrument Air Accumulator Check valve Test	11/15/06
248269 01	Operability Test of IA-YCV 1045	12/03/06
00265454	AC-1A, Performance Monitoring Test for CCW HX	01
00180415 01	AFW steam supply line check	09/17/04
00230114 01	AFW steam supply line check	04/28/06
00253641 01	AC-10D Raw Water Pump Quarterly inservice test	01/19/07
IC-CP-01-FW-64	Calibration of Back Pressure Trip Device on AFW FW-10	3
IC-CP-07-0001	Calibration of Pressure Gauges	9
IC-CP-01-0923	Calibration of AFW pump FW-10 steam inlet low pressure switch PS-923	2
OP-ST-AFW-0005	Auxiliary Feedwater Steam Supply line Check	3
OP-ST-RW-3031	AC-10D Raw Water Pump Quarterly in-service test	4
OP-PM-AFW-001	AFW flow path verification	9
FW-AFWPMP	Maintenance Rule Data	05/24/07

OP-ST-AFW-004	AFW FW-10 Operability test	4
IC-ST-AFW-3002	Instrument Air Accumulator check valve operability Test	4
IC-ST-IA-3001	Surveillance Test, SIRWT air accumulator check valve leakage test	7
IC-ST-SI-0002	Channel Calibration of SIRWT low level monitoring switches, Loops A, B, C and D/I-383	7
MR 0113	FCS Maintenance Rule Functional Scoping Data Sheet, (ACS RWSTRN), Raw water strainer	7
00251929 01	SIRWT air Accumulator Check	01/17/07
IC-ST-SI-002	Channel Calibration of SIRWT Low Level Monitoring Switches	4
SE-EQT-MX-0002	Equipment Test Procedure, Carbon Steel & alloy steel fasteners in-service test refueling inspections	8

Manuals

Number	Title	Revision/Date
TD A391.0090	Anchor Darling 20" Butterfly Valve with GH Bettis T3165 Operator	
TD 237. 0310	Bettis Nuclear Series Vendor Manual	0
TD 237.0300	Bettis Operating Manual and Instructions NT3. And NT4,	O
STM30	Reactor Protective System Systems Training Manual, Reactor Protective System Diverse Scram System	Vol 38
TD C173.0020	C&D Battery Installation and Operating Instructions	4
TD C173.0030	Specifications for C&D LCR Lead Calcium Batteries	4
TD C490.0370	ABB Vacuum Replacement Breakers	0

TD G080.2800	Static Exciter Regulator for AC Generators	1

Modifications

Number	Title	Revision/Date
EC 27405	Low Pressure Safety Injection Void Detection	10
EC 36972	LPSI Header Jockey Pump	0
DCR-10982	Aux Building Ventilation after SIAS of SI Puimp Room Cooling	
TM-96-42	CCW Surge Tank Relief Valve Setpoint an CCW System Thermal Relief Valve Gagging	0

Operator Training Scenarios

Simulator Scenario, Main Steam Line Break & Loss-of-Component Cooling Water
Simulator Scenario, Large Break Loss-of-Cooling Accident (Premature RAS)
Simulator Scenario, Reactor Cooling System Leak to CCW System
Simulator Scenario, MSLB Outside Containment & SBO (AFW failed to start, loss of IA)
Simulator Scenario, Loss-of-Raw Water System at Power
In-plant exercise AOP-18 "Loss of Raw Water."
In-plant exercise Initiate Air Compressor Backup Cooling
In-Plant exercise Minimizing DC Loads.
Performance Training Checklist, Local slow start of FW-10

Procedures

Number	Title	Revision/Date
SO-G-23	Surveillance Test Program	53
EOP-03	Loss-of-Coolant Accident	11/22/06
OI-ST-1	SI Normal operation	102
OI-DSS-1	Diverse Scram System (DSS), Normal operation	
OI-FH-3	Refueling Water Transfer from Refueling Pool to SIRWT	1/25/06
EM-PM-EX-0200A	Preventative Maintenance 4160 V Circuit Breakers	13
EM-ST-EE-0005	Battery No.1 Capacity Discharge Test	15
EM-ST-EE-0006	Battery No. 2 Capacity Discharge Test	13
EOP-07	Station Blackout	11

PED-EEI-2	Instructions for Power Cable Sizing	4
PED-EWP-10	Electrical Work Procedure - Cable Installation	8
SO-M-100	Standing Order - Conduct of Maintenance	43
SO-M-101	Standing Order - Maintenance Work Control	72
SP-CP-08-DEVAR-T1A1	Calibration of Devar Relay for T1A1	9
SP-CP-08-DEVAR-T1A2	Calibration of Devar Relay for T1A2	10
AOP-11	Loss-of-Component Cooling Water	11
OI-CC-1	Component Cooling System Normal Operation	58
OP-ST-CCW-3001A	Component Cooling Category B Valve Exercise Test	9
OP-ST-CCW-3005A	Component Cooling Category A and B Valve Exercise Test	7
OP-ST-RC-3004	Power Operated Relief Valves (PORVs) Low Temperature Low Pressure Exercise Test (PCV-102-1 and PCV-102-2)	24
PED-EWP-10	Electrical Work Procedure/ Cable Installation	8
QC-ST-CCW-3001	Component Cooling Water System Forty Month Inservice Test	0
SE-ST-CCW-3003	Component Cooling Water Surge Tank Leakage Test	10
SO-G-30	FCS Standing Order	111
IC-CP-01-0413	Calibration of Component Cooling Water Pressure Control Switch PCS-413	6
IC-CP-01-0412	Calibration of Component Cooling Water Pressure Control Switch PCS-412	6
NOD-QP-31	Operability Determination Process	34
SO-G-74	Fort Calhoun Station EOP/AOP Generation Program	12
PED-QP-3	Calculation Preparation, Review, and Approval	12
OI-RC-2A	RCS Fill and Drain Operations	54
SO-0-1	Conduct of Operations	72
AOP-17	Loss-of-Instrument Air	11
AOP-20	Loss-of-Bearing Water Cooling	1
AOP-18	Loss-of-Raw Water	6
AOP-28	Auxiliary Feedwater System Malfunctions	12
EOP-01	Reactor Trip Recovery	10
EOP-12	Functional recovery	12

TBD-AOP	Technical Basis Document -AOP	1

Surveillance Test Procedures

Number	Title	Revision/Date
SE-ST-CCW-3003	Component Cooling Water Surge Tank Leakage Test	10
SE-ST-RW-3002	Raw Water Pump Post Maintenance Operability Test	18
OP-ST-RW-3011	AC-10B Raw Water Pump Quarterly Inservice Test	30
QC-ST-SI-3008	Refueling High Pressure Safety Injection (HPSI) Leak Rate Determination	3
OP-ST-SI-3007	High Pressure Safety Injection System Pump and Check Valve Test	22
OP-ST-SI-3015	Containment Sump Recirc Valves Exercise and Position Verification Test	0
OP-ST-SI-3001	Safety Injection System Category A and B Valve Exercise Test	32
OP-ST-VX-3005A	Component Cooling Water Remote Position Indicator Verification Surveillance Test	7
OP-ST-CCW-3001A	Component Cooling Category B Valve Exercise Test	9
OP-ST-CCW-3001B	Component Cooling Category B Valve Exercise Test	4
OP-ST-SI-3002	Safety injection System Category A, B, and C Valve Exercise Test	25
OP-ST-CEA- 2006	CEA Rod Drop Test	11/26/06
OP-ST-CEA- 2006	CEA Rod Drop Test	12/2/06
OP-ST-CEA- 2006	CEA Rod Drop Test	8/26/03
OP-ST-CEA- 2006	CEA Rod Drop Test	4/17/05
OP-ST-CEA- 2006	CEA Rod Drop Test	5/30/05

Test Data For The Following Pumps and Valves

Component	Test Type/Frequency	Dates of Tests
SI-2A	Quarterly Differential Pressure and Flow Tests	Since 11/09/04
SI-2C	Quarterly Differential Pressure and Flow Tests	Since 02/17/05
SI-2B	Quarterly Differential Pressure and Flow Tests	Since 11/09/04
AC-10B	Quarterly Flow and Vibration Tests	Since 09/05/05
AC-10C	Quarterly Flow and Vibration Tests	Since 09/05/05
HCV-312	Quarterly Open and Close Stroke Time Tests	Since 09/05/05
HCV-480 and -481	Quarterly Open Stroke Time Tests	Since 02/17/05
HCV-345	Cold Shutdown Open and Close Stroke Time Tests	Since 04/19/01
HCV-344	Refueling Outage Open and Close Stroke Time Tests	Since 05/24/02
HCV-385 and -386	Refueling Outage Open and Close Stroke Time Tests	Since 04/19/01
LCV-383-1, -2, -3, and -4	Refueling Outage Open and Close Stroke Time Tests	Since 07/24/98
HCV-438A/B/C/D	Cold Shutdown Close Stroke Time	Since 02/24/05
AC-391	Quarterly Leak Test	Since 01/28/05
NG-113	Quarterly Leak Test	Since 01/28/05

<u>Work order</u>

Number	Title	Revision/Date
WO220640	D.G. Damper	10/12/2005
WO246656	Periodic Evaluation of Offsite Power Requirements	12/23/03

<u>Miscellaneous Documents</u>

Number	Title	Revision/Date
	Fort Calhoun Station Pump and Valve Inservice Testing Program Plan, 4th Ten Year Interval Through September 25, 2013	Revision 3, dated 06/09/06

	Pump Relief Request Number E-4 for Component Cooling water Pumps AC-3A, -3b, -3C, and Raw Water Pumps AC-10A, -10B, -10C, and -10D	
	Engineering Assistance Request & Response(EAR) 90-089	11/19/92
	Engineering Assistance Request & Response (EAR) 96-102	August 27, 1996
	PED-N-89-243B, Evaluation of Valve Stroke Times for Safety Injection and Containment Spray Systems	June 26, 1989
	PED-FC-1959, Stroke Time Limits for Specified Valves	May 9, 1990
	PED-FC-90-1959, Stroke Time Limits for Specified Valves	June 1, 1990
	Program Basis Document PBD-9, Relief Valve Program	12
	Modification Request 97-007, Correction of CCW System deficiencies	February 11, 1997
	HPSI AOI risk assessment,	5/3/2006
IN 1994-036	Gas Accumulation in the RCS	
IN 2006-021	Air Entrainment into the ECCS and CS Systems review	
PCR Minutes on CEDM 07-007	Continued Operations with an Inoperable CEA	
	10CFR50.59 Screening - Action Item 11 of CR199901103	
Operability Evaluation	Attachment to CR 200702441	
OPPD Letter: T. Short to H. Voigt	Application for Amendment,	3/13/1978
OPPD Letter: T. Short to H. Robert Reid	Revision to Amendment Request,	3/6/79
OPPD Letter: W. Jones to Robert Reid	Additional information re license amendment, request	9/6/79

OPPD Letter: T. Short to H. Voigt	Response to Questions regarding License Amendment,	4/28/78
	NRC Safety Evaluation for Amendment 52,	10/14/1980
NRC Letter: W. Jones to R. Clark,	Issuance of License Amendment 52,	10/14/80
NRC Letter R. Clark to W. Jones,	Amendment 52 to Facility Operating License	
NRC Letter	Issuance of Amendment 198 Re Charcoal Absorbers	
NEI 96-04	Guidance of Managing NRC Commitment Changes,	July 1999
	Journal of Fluid Mechanics,, Lubin and Springer, *The Formation of a Dip on the Surface of a Liquid Draining from a Tank*,	1967, volume 29 part 2 pp 385-390 9/1967
	Journal of the Hydraulics Division, ASCE, Jain, Raju and Garde, *Air Entrainment in radial flow towards Intakes*,	9/1976
	International Association for Hydraulic Research, Harleman, Morgan and Purple, *Selective Withdrawal from a vertically Stratified Fluid*,	8/1959
NRC Information Notice, 2007-02	Failure of Control Rod Drive Mechanism Lead Screw Mechanism Lead Screw Male Coupling at B&W Designed Facility	3/2007
ABB Letter	ABB 4kV Replacement Breakers - Control Voltage	7/14/1995
(Not Controlled)	Fort Calhoun Fuse List	7
NED-DEN-06-0087	Evaluation of MOV Degraded Voltage	(Not Dated)
NFPA-70	National Electric Code	2002 Edition
S069126	Purchase Order for C&D Batteries	12/11/1991
CID 910096/01	Erosion Program for Component Cooling Water and Raw Water	1/31/1992
CID 910032/01	Activities Related to Erosion Program for Raw Water (GL 89-13 Related)	2/15/1991
PED-SYE-90-006J	Service Water System Problems Affecting Safety-Related Equipment	1/4/1990

PED-STE-91-016	Generic Letter 89-13 Lessons Learned Follow-up Meeting	2/19/1991
LIC-90-0050	Response to Generic Letter 89-13	1/26/1990
CID 900590/04	Power-operated Relief Valve & Block Valve Reliability & Generic Issue 94, Additional Low Temperature Overpressure Protection for Light Water Reactor	11/18/1996
TDB-VIII	Technical Data Book, Equipment Operability Guidance	30
R06-AD-620	NLO Requal Lesson Plan, AOP-20" loss-of-bearing cooling water".	1/11/2007
00 NRC	Simulator Scenario, MSLB & Loss-of-CCW	0
01 NRC	Simulator Scenario, Large Break Loca	0
82105a	Simulator Scenario, RCS Leak to CCW System	4
82110	Simulator Scenario, MSLB Outside Containment & SBO	4
82111m NRC	Simulator Scenario, Loss-of-Raw Water System at Power	7
R07-SYS-11	Lesson Plan, AOP-18 "Loss-of-Raw Water."	6/11/2002
TAP-12	Training Administration Procedure, conduct of OJT	25
4-20-8	Lesson Plan, Emergency & abnormal operating procedures	2
PTC-0047	Performance Training Checklist, Equipment operator Nuclear-Auxiliary	3
JPM-0225A	Job Performance Measure, Initiate Air Compressor Backup Cooling	8
OI-CA-5	Operating Instruction, Instrument air system	80
PTC-0809	Performance Training Checklist, Local start of FW-54	7
OI-RW-1	Operating Instruction, Raw Water	78
PTC-0808	Performance Training Checklist, Local slow start of FW-10	5
OI-AFW-4	Operating Instruction, Auxiliary Feedwater System	63

PTC-0958A	Performance Training Checklist, Minimizing DC Loads	4
JPM-0304	Job Performance Measure, Minimizing DC Loads	5

DC Transfer Switches

6/6/07
DC Manual Transfer Switches - CDBI issue

QUESTION: How are the DC manual transfer switches evaluated with respect to the Appendix R analysis?

RESPONSE:
The switches are provided to align either a normal or emergency source of DC control power tothe plant switchgear (4160V and 480V). The switches are a break-before-make design. CQE(Class 1E) circuit breakers from each DC bus are provided for the normal and emergency positions of the DC manual transfer switch. The breakers protect the bus(es) from a fault within or associated with the switch. Therefore, for the case of a fire at the location of the transfer switch, a circuit fault and subsequent tripping of the DC bus circuit breaker is credited to occur. No specific analysis of the transfer switch is contained in the post-fire safe shutdown (PFSSD)analysis based on the methodology used by FCS. The methodology of the FCS post-fire safe shutdown analysis is to determine what equipment is necessary to safely achieve shutdown conditions following a postulated fire in any given fire area. Equipment location, cable and circuit routing, fire barrier location, fire hazards, fire suppression/detection are then determined for input into the analysis. In the case of these switches, the following assumptions are made:

- Only the normal alignment (power source) for the switch is credited. No credit is assumed for the emergency position for PFSSD.
- The circuit breakers protecting the feeder cable to each switch will trip to protect the bus under faulted conditions.
- For a fire in the fire area where the switch is located, the switch and power source is assumed to be lost.

These DC manual transfer switches are not specifically evaluated in the post fire safe shutdown analysis. The analysis assumes that circuits are protected by fault protection devices - circuit breakers or fuses. The analysis does not evaluate every circuit within a given fire area, therefore there is no detailed evaluation of the location and function of these manual transfer switches with respect to post-fire safe shutdown (Appendix R).
EA-FC-89-050, Associated Circuits Analysis, evaluated these switches and the associated loads as acceptable with regards to multiple high impedance faults caused by a fire.
FCS considers the methodology of the post-fire safe shutdown analysis to be appropriate and does not consider the location or function of these switches to be pertinent to the analysis based on the fact that the switch is treated as a single power source, i.e. no switch function is necessary.
Response: David Buell – Fire Protection Program Engineer – x7316
Inspector: Phil Wagner

References: EA-FC-89-050, OP-ST-EE-0010, USAR 8.3, Fig 8.1-1 (file 12234), FC06355, EAFC-
89-055, EA-FC-97-044

Diesel Generator Minimum DC Voltage for Field Flashing June 12, 2007

A question was raised regarding the minimum value of DC voltage that would be required at the diesel generator panels (AI-133A and AI-133B) to flash the field of the generators. GE drawing 44D302335 File No. 6622 shows "125 VDC for flashing" at the input to the AI-133 cabinet. If this value is not the minimum voltage required at these terminals then what is the minimum? (Note: the voltage in question is at location B2 of the drawing.)

Engineering has researched this question and come to the conclusion that there is not a single value of voltage that would be required to flash the field under all circumstances due to variations in the residual magnetic flux of the generator rotor and variations in the assumed temperature of the field windings. Field flashing is dependent on the magnetic flux emanating from the generator rotor as the rotor spins within the stator windings. The magnetic flux is provided by three separate mechanisms: a contribution from the residual magnetism of the rotor core, a contribution from current flow from the station battery and a contribution from current flow from the generator stator output as voltage induced in the stator windings is fed back to the field through the exciter rectifiers.

Many generators, including some generators at nuclear plants, do not use any external field voltage to flash the field, but instead rely just on the residual magnetism in the rotor core iron. This residual magnetism is always present in iron core rotors but the strength of the magnetic field may vary depending on generator's condition, age and the amount of time that has passed since the last operation of the generator. When the rotor spins inside the stator windings the magnetic flux from the residual magnetism induces voltage in the stator, and a portion of the stator output voltage is fed back to the excitation circuit. This stator AC voltage output is rectified by the exciter to DC voltage for the generator field. According to the generator open circuit saturation curve, when the output of the generator stator is at about 25% of rated voltage, the output from the excitation transformer to the field winding would be 60 volts. This 60 volts is rectified by the exciter circuit and contributes 60 volts / 6.2 ohms = 9.6 amps of current flow (and therefore additional flux) to the field. The generator manufacturer publishes a characteristic generator curve for the FCS generator that shows that 10 amps of field current will produce approximately 25% of full voltage output from the generator. This output voltage value is continually fed back to the exciter rectifier where it produces more and more field current until full voltage is achieved. The logical conclusion that can be reached is that even a small amount of residual magnetism will flash the field.

Normally, station battery voltage is applied via the field flash relay (2CR) to the field flash resistors. These resistors are current limiting resistors with a value of 5.1 ohms total resistance. (Four resistors are arranged such that each of the two pair of 5.1 ohm resistors are in parallel with each other and each pair is in series with the generator field as well as each other.) The field resistance is 1.3 ohms at 75 degrees C and 1.1 ohms at 25 degrees C. The addition of the field flash current limiting resistance and the winding resistance is a total resistance of 6.2 ohms. Normal field flash current (following a few time constants due to the inductive field circuit) would be 125 volts / (1.1 + 5.1 ohms) = 20 amps. The normal field current causes the field flash to occur in around one to two seconds. Lower levels of current may require longer periods of time to achieve the same voltage output.

The following query was sent to System Engineers at approximately 50 nuclear power plants in the US via the Electro Motive Diesel Generator Owners Group (EMDOG):

One of the questions being asked by the NRC is the minimum voltage required to flash the generator. We have searched our technical manuals and have not found a value.

Our generator is a General Motors Corporation, Electro-Motive Division model A-20-C2. Is there anyone who has a value for minimum voltage required to flash the generator, or who can give us guidance on how to calculate the value.

Approximately 10 responses have been received. No other plants reported having been asked this question about minimum field flash voltage during their CDBI inspection and no other plants had values for the minimum field flash voltage required to flash their field. Several respondents indicated that their diesels would flash at the minimum expected DC bus voltage, but no respondents indicated they had ever done any testing to verify this assumption. Several respondents indicated that they believed their diesels would flash on residual magnetism alone. One plant has an abnormal operating procedure for using a 12 volt car battery for flashing the field in the event that the field does not flash from residual magnetism. Another plant indicated that the question of minimum field flash voltage may be in the realm of severe accident management guidelines rather than plant accident design basis.

A need or requirement for FCS to determine the reduced DC voltage available for field flash has never been identified. The FCS degraded DC voltage calculations (FC05690) have determined that the minimum voltage expected at the diesel panels is 104.5 volts DC. The minimum voltage required to operate the diesel field flash relays (which must operate to complete the field circuit) has been determined to be 92 volts DC. If at least 92 volts DC is present at the AI-133 panels it is reasonable to assume that the diesel field flash will occur.

Fort Calhoun Station Position on Emergency Diesel Generator Field Flash Voltage

Fort Calhoun Station emergency diesel generator Flashing

The emergency diesel generator System Engineer was contacted at ANO. Unit 1 has an EMD diesel and generator, approximately 2750 kW rate power. This is nearly identical to the FCS emergency diesel generator approximately 2700 kW rated power. ANO have a procedure to start the diesel on residual magnetism and a surveillance test to verify this.

Unit 2 has an EPI generator and they have a procedure to use a backup field flash circuit of 24 volts. We have a copy CR-2-99-0615 from ANO in a report and it states they have contacted the EPI vendor and the generator would flash as low as 12 volts.

Therefore, due to the similarities of the FCS diesel and the ANO Unit 1, FCS is confident that the diesel would flash using residual magnetism with no voltage applied. The FCS Degraded Voltage Calculation FC05690 has determined that the voltage at the end of 4 hour station blackout scenario would result in a voltage of 104.5 volts at the diesel panel (i.e. field flash terminals) and would have enough voltage (104.5 volt margin) to successfully flash the field. In addition the 104.5 volts is greater than the pickup voltage of 92 volts for the field flash relay and this would be more than adequate to start the generator automatically without taking manual action.

Joseph F. Jacobsen
Nuclear Design Engineer
(Dated 6/15/07)

The team provided the following information request in writing to the licensee prior to the inspection.

Initial Information Request
Component Design Basis Inspection (71111.21)
Fort Calhoun Station

Please provide the following information in order to support the NRC's component design basis inspection effort at your facility. If there are problems obtaining any of this information, please call the Team Leader, Ronald Kopriva at (817) 860-8104 to discuss alternate arrangements. We would like to have the information ready when we arrive on site for the "bag-man" portion of the inspection on May 1, 2007.

We prefer, but it's not required, that the information be provided electronically and in a searchable format, such as Adobe, Word, Word Perfect, or Excel. Other licensee's have found that providing the information on a CD is effective and efficient.

1. The risk ranking of components from your site specific probabilistic safety analysis sorted by Risk Achievement Worth and by Birnbaum Importance.

2. A list of your top 500 cutsets from your probabilistic safety analysis.

3. Risk ranking of operator actions from you site specific probabilistic safety analysis sorted by Risk Achievement Worth. Provide copies of your human reliability worksheets for these items (you may limit this list to the 100 most risk significant actions).

4. If you have an external events or fire probabilistic safety analysis model, provide the information requested in Items 1 and 2 for external events and fire.

5. Any pre-existing evaluation or list of components and calculations with low design margins (i.e. pumps closest to the design limit for flow or pressure, diesel generators close to design required output, heat exchangers close to rated design heat removal etc.)

6. For the last two years, a list of operating experience evaluations, modifications and corrective actions sorted by component or system. A one line, or short, description is acceptable.

7. A list of any common-cause failures of components in the last 5 years at your facility.

8. A list of Maintenance Rule functions.

9. A list of your Maintenance Rule a(1) components.

10. A list of your current temporary modifications.

11. A current list of "operator work arounds."

12. Piping and instrument drawings for your emergency core cooling systems, emergency diesel generators and off-site power supplies. At this time, only the mechanical piping drawings are needed for the emergency core cooling systems and the emergency diesel generators.

In addition to the above, if available electronically, please provide a copy of each of the following on CD.

1. Final/Updated Safety Analysis Reports

2. Technical Specifications

3. Design Bases Documents for the emergency core cooling systems (including auxiliary feedwater), emergency diesel generators and off-site power supplies

4. System descriptions or operator training manuals for the emergency core cooling systems, emergency diesel generators and off-site power supply systems

Thank you for your cooperation in these matters.