APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-298/89-03 Operating License: DPR-46

Docket: 50-298

License: Nebraska Public Power District (NPPD)
P.O. Box 499
Columbus, NE 68602-0499

Facility Name: Cooper Nuclear Station (CNS)

Inspection At: NPPD General Office, Columbus, NE

Inspection Conducted: February 13-17, 1989

Inspectors: J. Dyer, Chief, Team Inspection Development, NRR (SSFI Team Leader)
C. VanDenburgh, Senior Operations Engineer, NRR
S. Kobylarz, ERC
W. Sherbin, ERC

Approved: [signature] for 4/10/89
G. L. Constable, Chief, Reactor Projects Section C, Division of Reactor Projects Region IV (team leader) Date

Inspection Summary

Inspection Conducted February 13-17, 1989 (Report 50-298/89-03)

Areas Inspected: Special, announced followup inspection of remaining unresolved items associated with the NRC Safety System Functional Inspection (SSFI) conducted May 11 through June 19, 1987. The SSFI had raised questions about the design and operational capabilities of the CNS emergency electrical system, auxiliary support systems, and other related issues. The focus of the followup inspection was to evaluate the resolution of the remaining open issues.

Results: In general the NRC staff found that the service water and electrical system as-found in 1987 were capable of performing their intended safety function; however, at the time of the inspection the systems did not meet existing design requirements. The final engineering evaluation of several of these issues was not complete at the time of the followup inspection; however, NPPD provided the needed technical information subsequent to the inspection. Although the NRC staff was not satisfied with the timeliness of corrective actions, significant programs to improve engineering documentation were observed. This included an as-built verification and design criteria reconstitution program. At the time of the SSFI, it appeared to the NRC staff that issues were not being properly reported to the NRC. The followup inspection revealed that NPPD management believed that issues identified by the NRC did not need to be reported to the NRC because of apparent redundancy. NPPD reviewed the SSFI report and began reporting NRC identified issues during the followup inspection. NRC review of licensee identified deficiencies since the SSFI indicate that NPPD was properly reporting issues to the NRC.

Three violations of NRC requirements were identified (failure to maintain fan coil units within design flow requirements, paragraph 3; failure to report NRC identified issues, paragraph 9; and failure to properly trend service water pump operating data, paragraph 12). No response to these violations is required.

DETAILS

1. Persons Contacted

NPPD

H. G. Parris, Vice President, Production
L. Kuncl, Nuclear Power Group Manager
R. E. Wilber, Division Manager, Nuclear Engineering and Construction
V. L. Wolstenholm, Division Manager, Quality Assurance
T. J. Arlt, Nuclear Licensing Specialist
W. C. Fisher, Electrical Engineering Supervisor
M. Boyce, Nuclear Licensing Engineer
K. Dowe, Mechanical Engineering Supervisor
S. McClure, Engineering Manager
A. Heymer, Manager, Configuration Management
G. A. Trevors, Division Manager, Nuclear Support
K. Walden, Licensing Manager
M. A. Hillstrom, Assistant Mechanical Supervisor
M. J. Bennet, Nuclear Licensing Engineer
J. R. Hotovy, Lead Mechanical Engineer
J. R. Hackney, Senior Staff Engineer
A. G. Boesh, I&C Engineering Supervisor
K. Almquist, Project Manager
W. Fehrman, Project Manager
L. Kohles, Department Manager, Nuclear Projects & Construction
G. Smith, Acting Licensing Manager
G. Horn, Division Manager, Nuclear Operations
J. Meacham, Senior Manager, Technical Support Services
E. Mace, Engineering Manager
R. Krause, Technical Support Staff
R. Brungardt, Operations Manager

Other NRC Personnel

P. W. O'Connor, Project Manager, NRR
G. Pick, Resident Inspector

2. Background

An NRC Safety System Functional Inspection (SSFI) of Cooper Nuclear Station's (CNS) emergency electrical system and its auxiliary support systems was conducted May 11 through June 19, 1987. On June 30, 1987, at a management meeting held in the Region IV office, NPPD described their corrective action program for some of the more potentially significant issues. This program and its status was further described in letters dated July 24 and August 14, 1987. The NRC staff issued the SSFI inspection report (50-298/87-10) on September 22, 1987. On November 23, 1987, NPPD provided a response to the SSFI inspection report which included specific responses to the deficiencies (unresolved items) as well as the broader programmatic issues. Unresolved Items 298/8710-04 and -06 were reviewed by the NRC staff and closed by letter dated December 22, 1987.

A followup inspection was conducted February 13-17, 1989, to review the licensee's overall activities and responses to various unresolved items that were identified by the NRC inspectors during the CNS SSFI. The object of the followup inspection was to review documentation prepared and/or assembled by the licensee on each outstanding unresolved item to assess whether the systems involved were capable of performing their intended safety function. As part of the followup activity, the NRC inspectors requested the documentation, prepared by the licensee after the SSFI, that established the adequacy of the design for those systems where the equipment performance or functional capability were questioned during the SSFI. The following is a summary of the inspectors' findings during the followup activity for the unresolved functionality concerns under review.

3. Unresolved Items 298/8710-01, -02 Statement of Concern

The service water system may not be capable of providing adequate cooling to the emergency diesel generators (EDGs) and to other essential loads during worst-case accident scenarios.

The actual heat removal capabilities of the service water system were not measured. Instead, system flows were measured which did not account for heat exchanger fouling and the resultant loss of heat exchanger capabilities. It appeared that adequate testing had never been performed to ensure that adequate flow could be provided to the EDGs under the design basis scenario of one pump supplying all heat exchanger loads.

Followup Inspection Findings

The licensee performed Special Test Procedure (STP) 87-011, "Post-LOCA Service Water System Flow Test," during the outage in May 1988. The purpose of the test was to quantitatively verify actual heat removal capabilities of the essential service water heat exchangers. The inspection team reviewed the technical content of the test and test results and made the following observations:

A. STP 87-001 appeared to thoroughly test the system for all configurations of post-LOCA lineups. The licensee took prompt corrective actions for problems encountered during testing.

B. After completing STP 87-011, the licensee initiated a periodic program of cleaning and testing the service water system to ensure that adequate cooling would be provided in the future.

C. The as-found service water flow to the control building basement Fan Coil Unit (FCU) FC-C-1A was 56 gallons per minute (GPM) instead of the 146 GPM design requirement. FCU FC-C-1A is located in the residual heat removal service water (RHRSW) booster pump room. The apparent cause of low flow was a blocked inlet strainer. The small openings of 1/16 inch suggest that it was a startup strainer. During the performance of the STP, the strainer was removed and the coil was then back-flushed. Subsequent readings showed that the flow increased to 75 gpm, which is the current flow rate.

Since the design flow was 146 gpm, the team requested calculations of the estimated RHRSW room temperature from the licensee to justify the as-found FCU FC-C-1A flow-rate condition of 56 gpm and the current flow rate of 75 gpm. Calculation NEDC 89-1426, dated January 26, 1989, showed that the temperature in the RHRSW room would stabilize at 116°F with 75 gpm of 85°F service water flow. Calculation NEDC 89-1455, dated February 17, 1989, showed that the temperature would stabilize at 122.6°F with 56 gpm of service water at 85°F. The design temperature of the RHRSW booster pump room is 104°F. The licensee evaluated the effects of the elevated pump room temperature in a letter from Mr. W. C. Fischer to Mr. K. J. Done, dated February 7, 1989, which stated that the brief elevated temperature of 116°F (75 gpm flow) will have no significant effect on essential equipment in the area. Although no analysis specifically addressed the elevated temperature of 122.6°F for the as-found condition of 56 gpm, the letter of February 7, 1989, stated that the lowest temperature rating of equipment in the room is 140°F continuous for the pump motors.

At the time of the followup inspection, the licensee had not determined whether the as-found flow of 56 GPM would have provided adequate cooling to the control building basement. As noted above, subsequent to this followup inspection NPPD provided analysis that indicated that the as-found flow of 56 GPM would have provided adequate cooling. The team concluded that the licensee had not adequately evaluated the as-found condition for reportability purposes. The reportability aspects of this issue are addressed in paragraph 9 of this report.

D. Service water flow to EDG heating and cooling Coils HV-DG-1C for EDG-1 and HV-DG-1D for EDG-2 exhibited low water flow during STP-87-011. The flow was measured in the 67 to 74 GPM range, with a design flow of 115 GPM. Airflow measurements were taken in May 1988, and the flow was initially reported to be 14,700 cfm for HV-DG-1C and 20,300 cfm for HV-DG-1D. The design airflow is 36,350 cfm. While evaluating the as-found condition in response to the NRC Team questions, the airflow of 14,700 cfm was found to be in doubt based on a meeting between Mr. E. R. Schimonitz (TABCO) and Mr. R. C. Arnold of APA on February 23, 1989, and a letter (No. ANL 117.27.163) from Mr. R. C. Arnold to Mr. G. S. McClure dated February 24, 1989. The instrument connection used for the initial test was down stream of installed security bars. These security bars caused turbulence which distorted the test results. NPPD installed a new instrument connection in an area of undisturbed air flow. The actual as-found airflow is now believed be 24,000 cfm for HV-DG-1D, based on conversations with NPPD Engineering. The coils were steam cleaned, and the filters changed in May 1988 with the resulting airflow of 31,680 cfm (DG-2) and 33,930 cfm (DG-1). There is currently a preventive maintenance action to clean the coils and change filters.

APA Calculation No. 117.56.01, dated January 20, 1989, indicates that minimum airflow of 29,000 cfm is required with a water flow of 40 gpm to keep the room below 125°F. The licensee performed Calculation NEDC 89-1622, dated February 25, 1989, which indicated that the room temperature could have gone to 127.7°F for the "as-found" coil condition before steam cleaning. The diesel speed regulator is rated at 120°F (letter from Mr. W. C. Fischer to Mr. K. Done, dated February 8, 1989), which is less than the calculated maximum ambient for both the as-found and the current condition. However, temperature tests performed by a consultant for the licensee showed a temperature profile in the room indicated that essential equipment mounted on or near the diesel would be exposed to actual temperatures less than the predicted maximum allowed temperatures.

As in C above, the as-found condition had not been evaluated for reportability. Reportability issues are discussed in paragraph 9 of this report.

The NRC inspectors reviewed Procedure 6.3.18.5 for service water system post-LOCA flow verification. The team also reviewed procedures for performance evaluation of reactor equipment cooling (REC), RHR, and DG jacket water and lube oil cooler heat exchangers. Also, General Electric calculated the thermal performance of the RHR heat exchanger and concluded that "A" and "B" heat exchangers have heat transfer capabilities greater than the design values (Cooper Task No. 170, dated February 2, 1989, from General Electric). No additional problems or questions were identified.

Although the as-found condition of the two fan coil units discussed above had not been analyzed in a timely manner, NPPD had conducted a thorough system test and analysis that indicated that the current design and operating condition was adequate for its intended purpose. Subsequent analysis now indicates that the as-found condition of both fan coil units was sufficient to provide adequate cooling at the time of the inspection, in 1987, although this was not known until February 1989. The failure to maintain the required flow through the fan coil units discussed in 3.c and 3.d above is an apparent violation of NRC requirements (298/8903-01). Unresolved Items 298/8710-01 and -02 are considered closed

4. <u>Unresolved Item 298/8710-03 Statement of Concern</u>

This item concerned inadequate operating guidance and training provided for casualty procedures. The original inspection identified that the service water casualty procedures provided inadequate operator guidance for operation with a loss of emergency power or a loss of the nonessential air system, and for balancing system flows following the loss of emergency power. In addition, inadequate communication existed between the control room and the control station for the EDGs.

Followup Inspection Findings

The licensee issued Revision 9 to Abnormal Procedure (AP) 2.4.8.3.1, "Service Water System Casualties," on November 25, 1987. This revision provided additional operator guidance in Steps IV.D.3.a and IV.D.3.b for redirecting service water flow to essential loads on loss of either EDGs or the plant air system. Revision 9 also provided operator instructions for manual isolation and balancing of system loads and for the loss of the 480 VAC vital load centers. The inspection team verified that the licensee routed the revision to all licensed operators and included the procedure in the annual operator requalification training. The team also verified that communications were improved between the control room and diesel generator room through the installation of a new phone system.

The inspection team reviewed the changes to AP 2.4.8.3.1 and identified several discrepancies between the sections which provided operator actions for loss of EDG-1 and EDG-2. These discrepancies involved steps, applicable to both procedures, which were not incorporated into both sections. For example:

A. Step 3.a.4 isolated both loops of heating, cooling, and ventilation (HVAC) system for EDG-1; however, Step 3.b.6 did not isolate both of the HVAC loops for EDG-2 (i.e., Service Water Valve SW-265 was not closed).

B. Step 3.b.9 isolated service water flow to Fan Cooler FC-C-1A; however, Section 3.a did not have similar actions for the isolation of the fan cooler.

C. The first note of Step 3.b, which provided operator actions for loss of the plant air system, incorrectly referenced only two of the three required action steps.

A licensee representative said that the above discrepancies were not in the original draft, but arose during a structural revision to the procedure and were not identified during the approval process. The licensee indicated that action would be taken to correct these deficiencies in the next revision of the procedure. Although these weaknesses reduced the effectiveness of this procedure, it did not appear to render the procedure inadequate for its intended purpose. The inspection team concluded that further licensee action may be necessary to correct the weakness in the review process that allowed these discrepancies to remain in the procedure thru the review process and to ensure that other procedures do not contain similar problems. Unresolved Item 298/8710-03 is considered closed.

5. Unresolved Item 298/8710-05 Statement of Concern

The startup and emergency transformers may not be properly sized to provide adequate voltage to start all the emergency core cooling system loads as designed.

Followup Inspection Findings

The inspectors reviewed portions of the ac voltage drop analyses, NPPD Calculations 87-132 and 87-132A, and Burns and Roe voltage drop Analyses ET05 and ET06. The review focused on the electrical distribution system in the mode when it receives power from the emergency station transformer, which is supplied by an Omaha Public Power District (OPPD) system 69-kV line. The team reviewed the input data, assumptions, and results of the study to verify the adequacy of the design of the emergency offsite power supply. The results of the calculation were found to be acceptable. Also, the inspectors reviewed the 480-volt voltage study performed by the licensee and consultants. A review similar to the above was performed and the results were found to be acceptable.

The inspectors noted that the licensee devoted considerable resources and effort after the SSFI to upgrade the scope and quality of the analyses of the AC electrical distribution system. The inspectors were encouraged to find this effort in the ongoing analytical activities in the electrical discipline. Unresolved Item 298/8710-05 is considered closed.

6. Unresolved Item 298/8710-07 Statement of Concern

The HVAC system may not be able to provide adequate cooling to the AC switchgear, DC switchgear, and station battery rooms. Excessive temperatures could prevent proper operation of essential electrical equipment and systems in the rooms.

The HVAC systems for the essential AC switchgear, DC switchgear, and battery rooms are designated as nonessential, nonsafety-related. On a postulated loss of ventilation, the cooling of the switchgear rooms becomes critical for the continued operation of the electrical switchgear, as well as other safety-related electrical equipment located in the area. During cold weather conditions, a loss of HVAC could cause low battery room temperatures, which could adversely impact battery operability. Both the high and low ambient temperature conditions can potentially cause a common mode failure mechanism for the electrical switchgear and/or station batteries.

Followup Inspection Findings

The team reviewed the following calculations:

No.	Title	Date Prepared
NEDC 89-1456	Room Temperature for Switchgear Rooms 1F and 1G with Portable Ventilation	2/18/89

No.	Title	Date Prepared
NEDC 87-105	Switchgear Room Ventilation Duct and Fan Sizing Calculation	7/22/87
NEDC 87-144	Nutech Calculation Package NPD023.0302 (Estimate of Temperature in Battery and Switchgear Rooms)	8/19/87
NEDC 87-229	NED Review of Nutech Calculation NPD024.0300 (DC Switchgear Room Thermal Analysis)	10/13/87
NEDC 88-011	NED Review of Black and Veatch Calculation for Battery Room Heat Loads	3/23/88

In response to the battery room heating concern, portable heaters were sized (Calculation NEDC 88-011) to provide temporary heat for battery rooms. Procedure 2.2.38.2 provides guidance in placing portable heaters in operation. Upon review of the procedure, the team found a weakness in that the power source for the portable heaters was a power feed from Division II only. The team was advised by the licensee that the procedure will be revised to include an additional alternate power feed from Division I.

Likewise, a portable ventilation system was designed to provide ventilation for DC Switchgear Rooms 1A and 1B and critical AC Switchgear Rooms 1F and G. Procedure 2.2.38.1 is in place providing instructions for operating the system, which consists of portable fans, portable ducting, and power cable.

Station Procedures 5.2.5, 2.3.2.18, 2.4.8.4.9, and 2.2.28 were revised on February 17, 1989, to provide more explicit directions, including alternate power sources (as described above), for placing the portable HVAC systems in operation. However, the revised procedures were not available for review by the team.

Calculation NEDC 89-1456 predicted that the temperature in the critical Switchgear Rooms 1F and 1G would be maintained at 101.8°F in Room 1F and at 105.5°F in Room 1G with temporary fans. Calculation NEDC 87-144 indicates that these fans should be placed in service within 1 hour after the loss of the main HVAC system. The NRC inspectors find that high ambient temperatures (greater than 160°F) could exist in the switchgear rooms, on failure of the normal nonessential HVAC system, in a relatively short period (approximately 1 hour). Therefore, the ability to detect the failure of the nonessential HVAC in a short time becomes critical. Since, the normal HVAC fans have multi-belted motor drives, a failure of the fan belts could result in the immediate loss of all switchgear room cooling. The team was concerned that the loss of switchgear room cooling could go undetected for a period greater than 1 hour, which would result in extremely high ambient temperatures in the switchgear rooms and the potential for damage or failure of the redundant safety-related AC and DC switchgear.

For example, prior to this followup inspection, the plant operators monitored the switchgear room temperature every 4 hours. Therefore, the licensee did not have adequate procedures in place to ensure that the temporary ventilation system would be operational within 1 hour on a loss of the main HVAC system.

At the exit meeting, the licensee indicated that surveillance of the switchgear room temperature will be increased to a 1-hour interval, and a design change would be implemented to provide a loss of airflow alarm.

Furthermore, NPPD did not have any test or operational data which validated the adequacy of the temporary ventilation system during high ambient outside air temperature conditions. The inspectors were concerned that the temporary ventilation system would not be effective in maintaining a 105°F room ambient, as the analysis indicated, especially when outside air temperature conditions approached or exceeded 100°F. High outside air temperature conditions are commonly experienced at the Cooper station site during summer. In fact, the temporary ventilation system, in conjunction with normal HVAC system, is used during high switchgear room ambient temperature conditions to maintain the switchgear room ambient at less than 104°F.

The team understands that the licensee is evaluating the maximum steady-state room temperature during temporary ventilation as a result of the team's concerns. According to a letter from Mr. W. C. Fischer to Mr. K. J. Done, dated February 21, 1989, ". . . a sustained ambient of 131°F will not produce any significant detrimental effects on the essential equipment located in the critical switchgear rooms." Nevertheless, the team believes that the ability of the temporary ventilation system to maintain the maximum "as analyzed" ambient temperature should be confirmed by suitable test.

During discussions with the District's licensing engineers, the inspectors found that the plant Appendix R study and program have not evaluated the need to provide ventilation for the critical switchgear rooms during plant fire conditions which could damage the normal ventilation system. 10 CFR 50, Appendix R, III.L.2.e, requires that the supporting functions shall be capable of providing the process cooling, lubrication, etc., necessary to permit the operation of the equipment used for safe shutdown functions. The licensee's Appendix R compliance assessment project consultant, EPM, stated in a letter dated February 21, 1989, that the interim compensatory measures contained in CNS Procedures 5.2.5, 2.2.8.4.9, 2.2.38, and 2.2.38.1 would be adequate to address postfire high ambient temperature concerns in the areas containing essential switchgear.

The team believes that the lack of adequate review and evaluation of the critical switchgear room HVAC requirement from the Appendix R program may be indicative of a generic weakness in the program to evaluate the need for other essential plant ventilation.

A consultant for the NPPD has performed a study titled "Cooling Study for the Essential Equipment Rooms for Cooper Nuclear Station," dated September 7, 1988. The study addresses various options for installing a safety-related HVAC system for the essential or critical equipment rooms. The team was advised that funding has been approved for the design of a new HVAC system. The installation of a safety-related HVAC system for the critical switchgear rooms is planned for the 1990 outage.

Although the temporary ventilation was not formally tested, the licensee stated that the volume flow rate of the portable fans was so significantly higher than the normal ventilation that it was felt that it was obvious that sufficient cooling was available. This system was routinely used during summer months but test data had not been taken. The potential impact of a fire on the use of this portable ventilation did not appear to have been considered, however, it was observed that the potential for a sustained fire in the adjacent critical switchgear rooms was very low. Pending the completion of the HVAC upgrade noted above the short-term improvements appear to be adequate. Unresolved Item 298/8710-07 will remain open pending an NRC inspection of the 10 CFR 50 Appendix R, issues related to the HVAC used in the critical switchgear rooms.

In addition, the issue of the apparent need of a nonsafety grade HVAC system to ensure the operability of the Safety Grade Critical Switchgear will be referred to the Office of Nuclear Reactor Regulation to determine whether a Safety Grade System should be required.

7. Unresolved Item 298/8710-08 Statement of Concern

There was no voltage study to demonstrate that critical 120 Vac electrical components would be provided adequate voltage during accident conditions.

Followup Inspection Findings

The team began a review of a selected portion of the 120 Vac system voltage analysis, NEDC 87-132A, Attachment 2, APA Project 117.25, dated July 21, 1987, to verify the adequacy of the 120 Vac system voltage or to identify subsequent followup/review activity. For the 120 Vac panels which the team selected, Panels CPP, CPP-2, CPP1A, and CPP1B, the analysis either indicated adequate results or it identified the need for a more refined load study or upgrade of feeder cable as appropriate. The team was unable to complete this portion of the inspection, therefore, Unresolved Item 298/8710-08 will remain open pending further review by the NRC staff.

8. Unresolved Item 298/8710-09 Statement of Concern

The 4160 Vac electrical system did not appear to be adequately designed to accommodate EDG testing. The 4160 Vac switchgear appeared to be undersized for short circuit conditions that could occur during test configurations. The circuit breaker overload settings to protect the EDG during testing were also set above the stall rating of the diesel generator.

Followup Inspection Findings

The licensee acknowledged that the momentary and interruptable rating of the critical 4160-Vac switchgear may be exceeded by the short circuit duty of the power system during conditions when the EDG is tested. If a fault were to occur during conditions when the EDG is tested, the critical switchgear for the DG could fail. For this condition, the licensee has taken the position "that the ability to perform and maintain a safe shutdown of CNS from 100 percent power is not jeopardized." A key assumption of this position is the fact that the redundant shutdown train would not be affected adversely on the postulated failure of the switchgear.

The team reviewed the bases for the District's position. Two statements in particular did not appear to be well justified.

A. The District stated that "The magnitude of the fault, only 6 1/2 percent above the faulted capacity, is unlikely to cause damage to other equipment in the same division if the fault is associated with the breaker." The team requested the updated fault calculations to establish the required fault duty. Cooper Nuclear Station, 4.16 kV Fault Study, Summary Chart, page 3, dated November 19, 1987, showed 69,763 amperes asymmetrical available at Bus 1F and 1G when the diesel is tested. This value is more than 16 percent over the switchgear momentary rating of 60,000 amperes. The team requested documentation from the licensee that the switchgear manufacturer, General Electric, would agree that the faulted switchgear would not cause damage to other equipment in the same division or generate a missile on failure. However, no documentation was available to substantiate the licensee's claim.

B. The District stated that "The fault can only occur on one safety-related division since only one diesel is tested at a time. Therefore, a fault would not damage the redundant safety-related division." This claim assumes that adequate missile protection has been provided to the redundant division. However, it is not clear to the team that adequate missile protection exists in the switchgear room arrangement, since the licensee has no documentation which confirms that a missile hazard will not result from the potential failure of the switchgear. The redundant switchgear rooms are separated by a wall with a fire door. The missile rating of this wall and fire door needs to be confirmed for the worst case missile identified.

During the followup inspection, the licensee contacted General Electric to determine whether adequate bases for the above claims could be established. The team was advised that the licensee intends to pursue with General Electric the adequacy of the switchgear rating for the fault duty identified. Preliminary feedback from General Electric suggests that the switchgear may be adequate to withstand and interrupt the fault current available.

The licensee replaced the original generator overcurrent trip relays with solid-state directional overpower trip relays, set to trip on 110 percent of EDG rated power. The inspectors reviewed Design Change 87-133 which replaced the relays and WI 88-1157, dated March 11, 1988, which installed and tested the relays. The documentation reviewed was acceptable.

Although good engineering practices indicate that the EDGs and electrical switchgear should be protected from postulated faults during testing, the NRC staff did not require it as a license condition at CNS based on the premise that it was acceptable as long as testing was of short duration. Annual total run time for the diesel generators is about 1 percent of the time available. Unresolved Item 298/8710-09 will remain open pending NRC review of documentation noted above that indicates that faulted switch gear will not damage other equipment.

9. Unresolved Item 298/8710-10 Statement of Concern

This item concerned several instances in which the licensee failed to implement the reporting requirements of 10 CFR 50.72 and 10 CFR 50.73 and provide timely corrective actions for significant deficiencies on safety-related equipment. The licensee failed to report: (1) NCR 5227 concerning exceeding the allowable variance for annual EDG inspections, (2) NCR 4759 concerning missing pinions in Core Spray Pump 1B Suction Valve CS-MO-7B, (3) NCR 4600 concerning missing springs on primary containment vacuum relief valves, and (4) NCR 6383 concerning an unplanned reactor protection system (RPS) actuation that occurred while shut down. In addition, the licensee failed to evaluate the reportability of: (1) NCR 5056 concerning the installation of an undersized service water booster pump gland water pump, (2) NCR 6392 concerning installation deficiencies of control rod drive mechanism (CRDM) orifices which potentially affected CRDM alarm times, and (3) missing lockwires found on three valves during inspections performed as corrective action for NCR 4759.

Followup Inspection Findings

In the response to NRC Inspection Report 50-298/87-10 dated November 23, 1987, the licensee identified the corrective actions for these concerns. These actions included: (1) performing training on the reportability requirements by February 16, 1988, (2) revising AP 0.5.1, "Nonconformance and Corrective Actions," and (3) issuing new AP 0.27, "Component Operability," to provide detailed guidance concerning operability evaluations. The revisions to AP 0.5.1 involved requiring a documented reportability review for every NCR, assignment of due dates for initial disposition of NCRs, and the completion of a justification for continued operability for closeout of NCRs with incomplete corrective actions.

The inspection team verified that the licensee conducted reportability training of 32 station personnel on February 11 and 12, 1988, in two half-day sessions. The inspection team also reviewed the scope and cc :ent of the training materials and concluded that the training adequately addressed the requirements of 10 CFR 50.72 and 10 CFR 50.73. The inspection team verified that the licensee revised AP 0.5.1 on December 31, 1987, and issued detailed guidance for the determination of component operability.

During the course of this followup inspection the NRC inspectors learned of three significant misunderstandings by NPPD of NRC reporting requirements.

A. NPPD management was under the impression that they were not required to evaluate issues identified by the NRC for reportability. This longstanding belief apparently arose from casual conversations with members of the NRC staff sometime in the past. NPPD managers pointed out that NUREG 1022 does not address the actions that should be taken when an NRC inspector identifies an issue as a potential violation of NRC requirements. NPPD was of the view that in those cases that sufficient documentation of the issue was contained in the inspection report and the licensees response to any violations. The NRC staff pointed out that 10 CFR 50.72 and -73 do not grant exemptions from reporting for NRC identified issues indicating that reporting of all issues that meet reporting criteria is required without regard to how the issue was identified.

B. Some NPPD managers were of the view that if a condition was found and corrected while the reactor was shut down, it would not be reportable even if the facility had previously operated in that degraded condition. The NRC staff expects a utility to report conditions that existed during operation that, if found during operation, would have required a reactor shutdown regardless of when the condition was identified.

C. Some NPPD managers were also of the view that 10 CFR 50.72 reporting requirements require reporting only after engineering evaluation is complete in those cases where an evaluation is needed. This is based on the phrase 10 CFR 50.72(b)(2)(i) ". . . would have resulted . . ." which implies that a condition does not become reportable until engineering concludes that the condition would have resulted in principal safety barriers being seriously degraded or being in an unanalyzed condition that significantly compromises plant safety.

This view could lead to circumstances where engineering studies may result in a 1-hour report over a year after the condition was initially identified. Recent improvements in the LER program appear to address this issue; however, it was not clear during this inspection that NPPDs engineering organization felt a sense of urgency when evaluating potentially reportable events. The NRC staff believes that such issues should be reported promptly along with plans for any additional evaluations.

NPPD's stated practice with regard to LERs has been to minimize reporting to that which is required. The NRC inspectors detected no attempt to intentionally under report but rather a goal of meeting the regulations without over reporting. Based on a recommendation from the NRC staff, NPPD evaluated the SSFI report for reportable events. On February 17, 1989, NPPD reported five events to the NRC operations center. Changes to NPPD's reporting program were in progress at the close of this inspection. The changes were stated to include improved timeliness and early evaluation of the significance of identified conditions that may need a long-term engineering study for final resolution.

The inspection team reviewed several NCRs issued since the last inspection. From a sample of approximately 110 NCRs issued since the last inspection, the team performed a detailed review of the following NCRs: 88-151, 88-095, 88-085, 88-139, 88-167, 88-091, 88-135, 88-065, 88-077, 88-067, 88-051, and 88-073. No deficiencies were noted with the corrective action or reportability of these NCRs. In addition, NCRs 5227 and 4759 were previously reported to the NRC in LERs 87-20 and 88-10 respectively. NCRs 5056 and 6392 were determined to be not reportable. NCRs 4600 and 6383 were on a QA hold pending further evaluation at the close of the inspection period.

The inspection team concluded that recent emphasis by the licensee in this area has improved licensee performance. Additional emphasis on an interpretation of NRC reporting requirements that is consistent with the practices of other utilities is suggested. In that the NRC staff has concluded that there is reasonable assurance that the inspected safety systems would have performed their intended safety function had they been called upon, no violation will be issued for a failure to report in accordance with 10 CFR 50.72 and 73. Further review of LERs will be conducted in accordance with the NRC inspection program Unresolved Item 298/8710-10 is considered closed.

10. Unresolved Item 298/8710-11 Statement of Concern

Examples of deficiencies in design analysis performed by the licensee were identified including the use of incorrect calculation methods, assumptions, and design inputs. Additionally, drawings and design bases were not always updated to reflect station modifications.

Followup Inspection Findings

This concern was reviewed as a subpart of the other concerns reviewed in this report. In general, the design packages were of good quality with very few problems noted. A significant improvement was observed. In addition, NPPD has an extensive as-built verification and design criteria reconstitution program in progress. Considerable improvement in the overall NPPD engineering function is apparent. Unresolved Item 298/8710-11 is considered closed.

11. Unresolved Item 298/8710-12 Statement of Concern

This item concerned the adequacy of testing performed following maintenance on safety-related systems. The licensee failed to perform testing following maintenance on the EDG exhaust bypass valve, the EDG starting air compressor pressure switch and the gland water supply pump for the residual heat removal (RHR) service water booster pump. In addition, the maintenance procedures allowed the performance of troubleshooting without prior independent review or approval.

Followup Inspection Findings

As corrective action, the licensee revised Maintenance Procedure MP 7.0.1, "Work Item Tracking - Corrective Maintenance," to clarify the responsibilities for determining the adequacy of the postmaintenance test requirements. In addition, the licensee implemented a maintenance self-assessment with the assistance of the Institute for Nuclear Power Operations (INPO). As a result of the NRC concerns, the licensee committed to complete the self-assessment by December 31, 1987, and give first priority to completing the corrective actions for recommendations regarding postmaintenance testing. In addition, the licensee committed to perform INPO training of pertinent station personnel by December 31, 1987, and evaluate the training needs of other Nuclear Power Group personnel.

The licensee completed the maintenance self-assessment in December 1987. The assessment indicated that an action plan would be developed by May 1, 1988, and that close management attention was required to complete these corrective actions. In addition, the report recommended the development and implementation of a postmaintenance testing guide. Internal correspondence dated December 7, 1988, indicated that this effort was behind schedule and requested the development of a task force starting December 12, 1988, to develop the testing guide. Another internal memo dated January 23, 1989, indicated that the postmaintenance testing requirements would be included in a new maintenance procedure (i.e., MP 7.0.5) by March 1, 1989. One day prior to the inspection team's arrival, the licensee changed the schedule for implementation of this new procedure until March 25, 1989. The licensee conducted a 2-hour training session on the postmaintenance testing requirements on November 25, 1987, for 22 station personnel and determined that further training of nuclear engineering personnel was not required.

The inspection team concluded that the corrective actions for postmaintenance testing had not been implemented in a timely manner. The licensee committed in their response dated November 23, 1987, to expeditiously implement the recommendations regarding postmaintenance testing. However, the product of these recommendations had not been implemented 13 months after the completion of the assessment. NPPD management acknowledged that the completion date for this new procedure had been delayed several times; however, it was pointed out that this procedure was needed primarily during outages when most maintenance is conducted and the procedure would be complete and in use by that time. The NRC resident inspector reviewed the licensees interim practices for developing postmaintenance testing and agreed with the licensees view that adequate measures were in place provided that the procedure and associated training were in place prior to the next refueling outage which is scheduled to begin April 17, 1989. On March 9, 1989, NPPD approved Maintenance Procedure 7.0.5, "Postmaintenance Testing," Revision 0, for use at CNS. Further NRC action to evaluate the effectiveness of the postmaintenance testing requirements will be accomplished during a post outage maintenance inspection. Unresolved Item 298/8710-12 will remain open pending the completion of this inspection.

12. Unresolved Item 298/8710-13 Statement of concern

The trending program for the Service Water System inservice test data appeared inadequate. The team identified instances in March, June, and September of 1986 where service water pumps were operating in the alert range without the increased monitoring or corrective actions being accomplished as required. This error was not promptly detected because the latest reference values had not been used to establish the alert range.

Followup Inspection Findings

NPPD acknowledged the need for improved procedural controls in their November 23, 1987, response to NRC Inspection Report 50-298/87-10. The NRC inspectors reviewed the revised Service Water Pump Procedure 3.9. It was revised on January 31, 1988, to provide the normal, alert, and required action ranges superimposed on the trending graphs. The NRC inspectors also reviewed the latest pump test data and determined that trending is now in place.

The failure to properly trend service water pump operating data is an apparent violation of NRC requirements. Unresolved Item 298/8710-13 is considered closed.

13. Exit Interview 30703

An exit interview was conducted on February 17, 1989, with the licensee representatives identified in paragraph 1. During this interview, the NRC team leader reviewed the scope and findings of the inspection. On

March 31, 1989, in a telephone call with Mr. Greg Smith, Acting Manager, Nuclear Licensing and Safety, the SSFI followup team leader supplemented those findings by discussing the results of the inspection of documents provided after February 17, 1989. The status of the remaining SSFI open items was also discussed.