APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-298/89-32 Operating License: DPR-46

Docket: 50-298

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

Facility Name: Cooper Nuclear Station (CNS)

Inspection At: CNS, Nemaha County, Nebraska

Inspection Conducted: September 1-30, 1989

Inspectors: Gregory A. Pick 10-12-89
G. A. Pick, Resident Inspector, Project Section C, Division of Reactor Projects — Date

W R Bennett 10/12/89
W. R. Bennett, Senior Resident Inspector Project Section C, Division of Reactor Projects — Date

G L Madsen 10/19/89
G. L. Madsen, Project Engineer, Project Section C, Division of Reactor Projects — Date

Approved: 10/20/89
G. L. Constable, Chief, Project Section C, Division of Reactor Projects — Date

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Inspection Summary

Inspection Conducted September 1-30, 1989 (Report 50-298/89-32)

Areas Inspected: Routine, unannounced inspection of operational safety verification, monthly surveillance and maintenance observations, engineered safety features walkdown, and followup of previously identified items, 10 CFR Part 21 reports, IE Bulletin 88-07, and Information Notices.

Results: Within the areas inspected, one noncited violation was identified in paragraph 4 for an inadequate procedure. The licensee responded promptly and adequately to the concerns of IE Bulletin 88-07. Control room response to an automatic scram was excellent. A walkdown of the instrument air system demonstrated a satisfactory ongoing as-built program with some minor problems identified. Engineering evaluations for the root cause of the scram and of the anomalies during the scram were conservative and thorough.

DETAILS

1. Persons Contacted

Principal Licensee Employees

*J. M. Meacham, Senior Manager of Operations
*J. R. Ullmann, Supervisor Configuration Management
*E. M. Mace, Engineering Manager
*R. L. Beilke, Acting Radiological Manager
*R. A. Jansky, Outage and Modifications Manager
*G. E. Smith, Quality Assurance Manager
*R. Brungardt, Operations Manager
*H. T. Hitch, Plant Services Manager
*R. L. Gardnor, Maintenance Manager
*H. A. Jantzen, Instrument and Control (I&C) Supervisor
*G. R. Smith, Licensing Supervisor
*L. E. Bray, Regulatory Compliance Specialist
*C. M. Estes, Management Trainee

*Denotes those present during the exit interview conducted on October 4, 1989.

The inspectors also interviewed other licensee employees and contractors during the inspection period.

2. Plant Status

The plant operated at essentially 100 percent power until September 28, 1989. On September 28 at 11:36 a.m., the reactor scrammed due to an electrohydraulic (EH) system lockout. The reactor was taken critical on September 30 at 7:56 a.m. and was synchronized to the grid at 7:14 p.m.

3. Operational Safety Verification (71707)

The inspectors observed operational activities throughout the inspection period. Control room activities were observed to be well controlled. Proper control room staffing was maintained and professional conduct was continuously observed. Discussions with operators determined that they were cognizant of plant status and understood the importance of, and reason for, each lit annunciator. The inspectors observed selected shift turnover meetings and noted that information concerning plant status and planned evolutions was communicated to the oncoming operators.

On September 28, 1989, at 11:36 a.m. (CDT), the reactor scrammed from 100 percent power on low level EH fluid lockout. The EH fluid lockout generated a turbine control valve fast closure and subsequent reactor trip. All safety systems responded as expected with the exception of four anomalies described later in this report.

The licensee initially developed a list of all credible causes of the reactor scram. The engineering staff did a thorough job of evaluating each suspected cause and eliminating each cause except for spurious low EH fluid level switch operation. The most probable causes of the spurious low level switch operation were determined to be vibration due to operating equipment and inadvertent mechanical agitation.

Two to three minutes prior to the reactor scram, the licensee had shifted from operating EH pump A to standby EH pump B, which may have caused the unloader valve to operate abnormally, setting up vibrations in the low level switch. The licensee commenced a search of the Nuclear Plant Reliability Data System (NPRDS) to determine if similar problems had previously been identified on Westinghouse turbines. The NPRDS search identified a similar event which had occurred at North Anna Unit 1 in 1984. The North Anna vibration problem was attributed to unloader malfunctions caused by particulates in the EH fluid. After review of the information related to North Anna Unit 1, the licensee contacted the Westinghouse digital electrohydraulic (DEH) control system expert. The DEH control system expert stated that only an actual low level or mechanical actuation of the low level switch, due to vibration or bumping, could have caused a low level lockout. The licensee conducted testing of the EH system including repeated EH pump swapping in an attempt to repeat the problem. Similar vibrations and subsequent lockout signals could not be achieved.

Since no definite cause of the scram was determined, the licensee implemented the following corrective actions to prevent a similar occurrence in the future. A vibration recorder was mounted to the DEH skid to monitor and trend vibrations and Special Order (SO) 89-05 was issued stating that the DEH pumps are not to be shifted except for scheduled surveillances or emergency operations. Additionally, engineering was assigned longer-term corrective actions which consisted of evaluating preventive maintenance (PM) requirements for the DEH unloaders, evaluating the DEH reservoir level switches to a vibration resistant model, and evaluating the low level DEH fluid trip logic.

The four anomalies identified subsequent to the scram were:

° The feedwater (FW) startup flow control valves did not automatically open;

° The low pressure (LP) steam supply valve to the reactor feed pump turbines did not automatically close;

° The reactor recirculation pump trip (RPT) occurred which was initially unexpected;

° and the reactor equipment cooling (REC) Pumps C and D tripped during the fast bus transfer which accompanied the scram.

The first two anomalies were caused by the failure of a common control relay to actuate. The licensee discovered a wire trapped between the control relay contacts while attempting to determine the physical condition of the relay. The licensee suspects that the wire was routed in this fashion during the Control Panel B upgrade implemented during the 1989 refueling outage. All other relays in the back of Control Panels A and B were visually inspected with no other problems identified. The licensee is investigating the problem and has committed to complete the root cause analysis and identify required corrective actions by October 31, 1989.

The RPT was caused by the anticipated transient without scram (ATWS) high pressure circuitry which also caused an alternate rod insertion (ARI) scram. The trip setpoint of 1060 ±13 psig was installed during the 1988 refueling outage. The ARI/RPT was initially considered an anomaly, since its actuation during a scram from 100 percent power had not been previously experienced; however, since peak pressure reached 1084 psig, the licensee determined that the ARI/RPT was a normal occurrence.

The trip of REC Pumps C and D during a fast bus transfer was determined to be a normal occurrence. The on-shift operating crew had not previously observed the condition and initially considered it offnormal. As designed, the REC pump start circuit has a "seal-in" feature which drops out after 15 milliseconds. When the "seal-in" feature times out, the REC pump start circuit will not cause an REC pump start. A fast bus transfer takes approximately 100 milliseconds. Therefore, due to operating characteristics of the equipment involved, the pumps will sometimes trip. The possibility of having the REC pumps trip in this manner is noted in System Operating Procedure (SOP) 2.2.65, "Reactor Equipment Cooling Water System," Revision 26, dated February 8, 1988. Tripping of the REC pumps was not a safety concern as discussed in the Updated Safety Analysis Report. The licensee issued SO 89-04 to specifically communicate to all operators the possibility of REC pump trips during fast bus transfers. Additionally, the licensee committed to provide an implementation schedule to NRC by October 31, 1989, for altering of the REC circuit logic to prevent such trips.

Throughout the shutdown, the plant was maintained in a stable, hot standby configuration. Because of thermal stratification, the temperature difference between the reactor vessel dome and the reactor vessel drain exceeded the 145°F temperature limit for start of a recirculation pump. The operators lowered reactor pressure to get within the temperature limitations for start of the second recirculation pump. All surveillances required during an unscheduled shutdown were completed. Surveillance procedures with a frequency of 6 months were completed so that, if a problem occurred with these tests, the facility would not be placed in a limiting condition for operation. Ten unscheduled shutdown maintenance items were completed. These items included replacing the drywell floor drain sump (F1) pump bearings and limit switch adjustment on the inboard reactor sample valve.

The reactor startup commenced at 4:41 a.m. (CDT) September 30, 1989, and criticality was achieved at 7:56 a.m. The heatup and pressurization was controlled and the turbine was synchronized to the grid at 7:14 p.m. The heatup and pressurization were slow and carefully controlled as requested by station management and specified in the night order log. The control rod withdraw sequence was utilized.

Tours of accessible areas at the facility were conducted to confirm operability of plant equipment, including the fire suppression systems and other emergency equipment. Facility operations were performed in accordance with the requirements established in the CNS Operating License and TS.

The inspectors verified that selected activities of the licensee's radiological protection program were implemented in conformance with facility policies, procedures, and regulatory requirements. Radiation and/or contaminated areas were properly posted and controlled. Radiation work permits contained appropriate information to ensure that work could be performed in a safe and controlled manner. Radiation monitors were properly utilized to check for contamination. On September 27, 1988, the inspector observed a health physics technician determine the type and verify the location of contaminates on an individual's clothing. Proper precautions were taken to control further spread of the contamination.

The inspectors observed security personnel perform their duties of vehicle, personnel, and package search. Vehicles were properly authorized and escorted or controlled within the protected area (PA). The PA barrier had adequate illumination and the isolation zones were free of transient material. Site tours were conducted by the inspectors to ensure that compensatory measures were properly implemented as required. The PA barrier had adequate illumination and the isolation zones were free of transient material. On September 8, 1989, the inspector observed a vital area door locking mechanism changeout in accordance with security plan requirements due to a security employee termination.

No violations or deviations were identified in this area. Control of plant operations during the shutdown and while starting up was conservative. The root cause determination for the scram, elimination of other potential causes of the scram, and evaluation and correction of the anomalies were thorough and indicated good engineering judgement.

4. Monthly Surveillance Observations (61726)

The inspectors observed performance of and/or reviewed the following surveillance procedures (SP):

SP 6.2.2.3.12, "HPCI Turbine Stop Valve Monitor, Oil Pressure, and Supervisory Alarm Timer Calibration and Functional/Functional Test," Revision 16, dated August 10, 1989.

On September 1, 1989, the inspector observed the performance of this functional test of the high pressure coolant injection (HPCI) auxiliary oil pump low oil pressure sensor (HPCI-PS-2787). The auxiliary oil pump provides lubricating oil to the HPCI pump turbine when the main oil pump is not operating. The pressure sensor stops the auxiliary oil pump when the lube oil header pressure reaches 85 psig and starts the pump at 30 psig. A qualified I&C technician conducted the test in accordance with the procedure.

Initially, the technician connected the volt-ohm-milliamp (VOM) meter across the wrong terminals. The mistake was discovered when no movement of the VOM needle occurred as the test pressure was increased. After connecting the VOM to the correct terminals, the test was satisfactorily completed. The procedure failed to provide sufficient guidance to the I&C technician for proper connection of test equipment. This procedure inadequacy is an apparent violation of the requirements of 10 CFR 50, Appendix B, Criterion V. This apparent violation was discovered by the inspector, but was corrected by the licensee prior to the end of the inspection period. The licensee added a step to clarify where the VOM was to be connected prior to the end of the inspection period. The licensee committed to review the other I&C procedures by October 31, 1989, to determine if similar situations exist.

A Notice of Violation for this violation is not being issued because the criteria of Section V.A. of the NRC Enforcement Policy were met.

SP 6.2.2.3.11, "HPCI Gland Seal Condenser Hotwell Level Calibration and Functional/Functional Test," Revision 13, dated September 9, 1988.

On September 1, 1989, the inspector observed the performance of this functional test of the HPCI gland seal condenser hotwell level switches initiation logic. Proper communications were established with the control room and good radiological practices were observed. The level switches actuated as specified in the procedure.

SP 6.2.2.1.10, "4160 V Buses 1F and 1G Under-Voltage relays and Relay Timers Functional Test," Revision 14, dated August 31, 1989.

This surveillance functionally tests both the first and second levels of undervoltage (UV) relay and relay timer actuations for 4160 Vac critical switchgear Buses 1F and 1G. The inspector observed the test conducted on September 8, 1989. The undervoltage protection for Buses 1F and 1G was altered during the 1989 refueling outage to allow each bus to shed loads for equipment protection while being powered by the EDGs. The setpoint for Time Delay Relay 27X16/1G was 25 ±1.5 seconds which allowed sufficient time for all safety-related loads to sequence onto the bus. After Relay 27X16/1G times out, the load shed circuitry is reenabled.

During the performance of this surveillance, the Time Delay Relay 27X16/1G actuation exceeded the 26.5 second maximum time specified in the procedure. This was in the conservative direction because more time was allowed for the bus voltage to stabilize. From discussions with the licensee, the inspector determined that the time delay was chosen to allow sufficient time for bus voltage to stabilize without being exceedingly long. The test was conducted three separate times to verify that the maximum time was actually exceeded and not a recording error. Investigation by the licensee determined the time delay relay setpoint tolerance should be ±2.5 seconds. This reflects the manufacturer's tolerance for the relay with a 25-second setpoint. The licensee committed to approve a permanent procedure change incorporating the increased setpoint tolerance prior to the scheduled October 1989 surveillance test. The licensed operators conducting the test were knowledgeable about the purpose and scope of the test. Excellent communications were established among the operators.

One noncited violation was identified for an inadequate procedure.

5. Monthly Maintenance Observation (62703)

On September 25, 1989, the inspector observed maintenance activities related to work item (WI) 89-3906. This WI required the locating and correcting of an intermediate ground fault indication on the ground fault relay for the EDG No. 1 generator field. The electrician checked the mechanical linkages for binding and cleaned and burnished the contacts. Additionally, the contacts were adjusted to increase the tension to assure proper wipe. Documentation of the work activities conducted accurately reflected all tasks performed. All reviews and approvals were obtained. Postmaintenance testing assured proper operation of the ground fault relay.

On September 20, 1989, the inspector observed troubleshooting activities conducted by an I&C technician for WI 89-3867. The purpose of this WI was to determine the cause of a spurious alarm received in the control room related to a standby gas treatment system high efficiency particulate air (HEPA) filter.

Troubleshooting revealed an intermittent light in the photohelic which generated the alarm for a high differential pressure across the HEPA filter. A photohelic utilizes a light source and a photocell to generate a continuous electrical signal. Dimming of the light source broke the circuit causing the alarm. After replacing the light, the technician performed a calibration check and determined that the photohelic had failed. Using a calibration data sheet obtained from the instrument folder, the technician checked the instrument's calibration. The alarm actuated at 6 inches water vacuum instead of the required 2 inches water vacuum.

Since the same model number single element photohelic was not available, plant temporary modification (PTM) 89-042 was generated to replace the single element photohelic with a dual element photohelic. PTM 89-042 expires in 60 days, when a single element photohelic should be available for installation.

After determining that all plant instrumentation did not have a calibration procedure, the inspectors reviewed the instructions available to I&C technicians for conduct of surveillances, PM activities, and calibrations. Three different categories of instructions are available to I&C technicians: TS required surveillance, surveillances for instruments important to the operation of the facility but not required by TS, and noncritical instrumentation.

TS required surveillances are controlled by Volume 6 of the CNS Operations Manual. These procedures require SORC approval for any change in the procedure body or the attached data sheets.

Procedures for instrumentation important to the operation of the facility are located in Volume 14 of the CNS Operations Manual. Volume 14 procedures require SORC approval before they may be altered. Additionally, some Volume 14 procedures authorize the I&C Supervisor to approve changes to calibration data sheets for any of the instruments listed on an attachment to the procedures. For each listed instrument on the attachment there exists, in the I&C shop personal computer, a preprinted calibration data sheet with setpoints and tolerances. These sheets are revised as necessary and are used for calibrations when implementing PMs or corrective maintenance WIs. After the work is complete, the I&C foreman must sign the bottom of each calibration data sheet to indicate review and acceptance of the data.

There are six Volume 14 procedures that list approximately 369 instrument or instrument loop calibrations. Included in the list are those instruments located in: residual heat removal, HPCI, reactor core isolation cooling, instrument air (IA), service air (SA), and reactor feedwater control. The instruments provide system performance information and have no TS requirements.

The final category and type of control for conducting I&C work activities are noncritical instrument data sheets which are contained in instrument folders. This instrument performance information was obtained during original plant startup and is transferred from data sheet to data sheet each time a calibration is performed. SORC has no formal control of these setpoints and the calibrations are conducted to implement WIs. The I&C foreman reviews the completed data sheet prior to filing in the instrument folder.

No violations or deviations were identified in this area. The different categories used to provide guidance to the technicians for conduct of surveillances, PMs, and calibrations meet or exceed regulatory requirements and appear to be satisfactory. Documentation on completed WIs accurately reflected the work conducted. The troubleshooting activities conducted were thorough. Although no procedure was available, the I&C technician did a professional job of checking the instrument's calibration. All reviews and approvals associated with the work item and the PTM were performed.

6. Engineered Safety Features (ESF) Walkdown (71710)

The inspector conducted a field walkdown of the IA and SA systems. The field configuration was verified in accordance with SOP 2.2.59A, "Plant Air System Valve Checklist," Revision 2, dated August 31, 1989. Approximately 1800 valves out of an estimated 2150 were verified by the inspector. Thirty-two discrepancies were identified and are categorized as follows:

Number	Title
12	Missing tags which were previously in place
4	Problems previously identified and in process of being solved
5	Valves not positioned as stated in the valve checklist nor as represented on drawings
10	Minor description discrepancies
1	Valve improperly tagged and not identified by the contractor
32	Total

These discrepancies were presented to the licensee with a concern expressed about the adequacy of the drawing verification project. The categorization of the above discrepancies was done by the licensee while resolving the inspector's concerns. The discrepancies identified were of minor safety significance.

Discussions between the inspector and the General Office Configuration Management Supervisor determined that the contractor's original scope consisted of verifying the plant configuration utilizing IA piping and instrument diagrams (P&ID). The contractor was required to stop at the root valves represented on the IA P&IDs and not walkdown the related instrument rack diagrams.

The inspector determined that numerous IA system valves are located on other safety-related P&IDs or on instrument rack drawings. The IA valves on the other P&IDs are to be walked down as part of those system walkdowns and not during the IA walkdown. Presently, the IA instrument rack drawings are not required to be walked down.

From discussions with the licensee, the inspector determined that licensee management did not understand all aspects of the contractor's job scope and was unclear about the amount of work actually completed by the contractor. Licensee management stated that they would have become aware of any discrepancy in scope dur ng their final review of the project.

A walkdown of the instrument air system demonstrated a satisfactory ongoing as-built program with some minor problems identified.

No violations or deviations were identified in this program area.

7. Followup on Previously Identified Findings (92701)

(Closed) Open Item (298/8412-03) This item involved the failure to have established a formal written training program for the offsite technical support staff.

Training Program Description (TPD) 0507, "Corporate Support Training," Revision 0, dated February 23, 1989, provides "position required" and "task required" training requirements for the general office engineering staff. "Position required" courses included: general employee training (GET), ALARA, 10 CFR 50.59, and industry events. The only "task required" course is respiratory training. Each of the above courses had a requalification frequency specified.

The inspector determined from discussions with training department personnel that GET is taken as required and that 10 CFR 50.59 initial training/requalification training will be presented in September 1989 and October 1989 to assure that all engineers have received the training.

ALARA training for the technical staff is being developed by General Physics. Industry events were presented to the engineering staff and will be scheduled periodically in the future. This item is considered closed.

(Closed) Open Item (298/8636-04) Deficient As-Built Instrument Drawings: The licensee walked down the systems associated with the as-built drawings included in the open item. Design Change Notices (DCNs) were issued for updating the as-built drawings. The inspector verified that the DCNs were incorporated into the as-built drawings. This item is considered closed.

(Closed) Open Item (298/8706-05) Mislabeled or Misnumbered Equipment in As-Built Records: The licensee walked down the systems included in the open item. DCNs were issued and the associated as-built drawings were updated. The inspector verified that the DCNs were incorporated into the as-built drawings. Additionally, Procedure 2.2.20, "Standby AC Power System (Diesel Generator)," was revised to incorporate the updating of the as-built drawings. This item is considered closed.

(Closed) Open Item (298/8824-01) Implementation of Station Operations Review Committee (SORC) Training: This open item was established to track the implementation of a formal SORC training program and attendance by committee members.

The inspector reviewed the training requirements contained in TPD 0508, "SORC," Revision 1, dated April 26, 1989. The training included two "position required" lesson plans, 10 CFR 50.59 and Technical Specifications (TS), and one "task required" lesson plan, Industry Events.

Each of the above lesson plans had specified a requalification cycle. Memorandum CNSS895696 from G. R. Horn, Division Manager Nuclear Operations, to P. R. Windham, Technical Training Supervisor, dated April 28, 1989, documented that the SORC members listed on the TPD were certified to the TPD training requirements and that SORC was in a requalification status. The memorandum requested that the TS lesson plan be presented in the fall of 1989. The inspector determined that this training is scheduled to be presented in December 1989. Industry Events training will be presented to SORC in October 1989. This item is considered closed.

No violations or deviations were identified in this area.

8. Followup on 10 CFR Part 21 Reports (92701)

The following 10 CFR Part 21 reports were closed on the basis of the inspector's review of licensee documentation and discussions with personnel:

a. 87-074: Limitorque Supplied SMB-00 DC Motor Operators With Lead Wire Defects - The licensee's inspection of Limitorque SMB-00 motor operations in stock revealed no defective wires. The CNS approved suppliers list was changed to require that all limitorque operators received be inspected for wire damage. Limitorque has committed to inspect for lead wire damage prior to future shipments.

b. 87-084: Nuclear Valve Division of Borg-Warner Corporation Fasteners Installed In Motor Operator Valves - The licensee's search of purchase orders and equipment data files indicated that NPPD had purchased equipment from Borg-Warner; however, none of the valves were installed at CNS.

c. 88-004: General Electric Company Hydraulic Control Unit (HCU) Scram Solenoid Valve Rebuild Kits - CNS had previously received a Rapid Information Communications Services Information Letter dated July 2, 1986, regarding HCU scram valve rebuild kits and the subject concerns were addressed prior to the 1986 outage. The following actions were taken at CNS:

- Strip chart recordings of scram timing data for all rods was reviewed and no discrepancies were found.

- 69 rebuild kits in inventory were returned to General Electric for reinspection.

- Maintenance Procedure 7.2.49.5, "Scram Pilot Solenoid Valve Maintenance," was revised to include a final inspection of the core assembly.

- After refurbishment of a scram solenoid pilot valve, valve operation is demonstrated prior to returning the HCU to service.

Single rod scram time testing is then performed to verify control rod drive HCU operability.

d. 88-005: Kaman Instrument Corporation Defect in Particulate and Iodine Monitors - The gaseous effluent monitors manufactured by Kaman, identified in the CNS TS, do not require monitored particulate or iodine monitors. One of the CNS Kaman monitors is a model KMPG which is included in the Part 21 report. In order to avoid a potential future problem arising from chemistry procedure changes, the Kaman monitor was updated with the current recommended software.

e. 88-019: Limitorque Corporation Melamine Torque Switch Failures in SMB-000 and SMB-00 Valve Actuators - The initial review of records by the licensee revealed that 25 Limitorque SMB-000 valve actuators were suspect. A maintenance work request (MWR) was issued for the inspection and needed replacement of torque switches. As a result, 23 SMB-000 valve actuator torque switches were replaced.

f. 89-001: Cooper Bessemer Standby Diesel Generator Rocker Arm Failure - An MWR was issued for a visual inspection to look for cracks in the bosses on rocker arms in both emergency diesel generator (EDG) units. No cracks were identified. Additionally, two spare rocker arms in the warehouse were inspected and no cracks were identified. NPPD added a requirement to procurement receipt inspections to look for cracks in rocker arms.

The following Part 21 report remains open pending further licensee evaluations:

88-018: Limitorque Corporation - Reduced Starting Torque at Elevated Temperatures in SMB Valve Actuators with RH Insulated DC Motors - NPPD Engineering evaluated the SMB Valves actuators with the RH insulated DC motors and determined that Valves RR-MO-53A and RR-MO-53B would be required to operate at temperatures greater than specified in Limitorque's Part 21 report.

CNS provided Limitorque, by letter dated December 7, 1988, with the information specified in the Part 21 report:

- Motor Starting Torque - 100 ft. lbs.
- Voltage Rating - 250 VDC
- Maximum specified temperature at which motor will develop rated starting torque - 150 degrees Fahrenheit (°F)
- Accident temperature conditions - 296°F peak in 10 seconds and 175°F for 1 hour

By letter, dated August 24, 1989, Limitorque responded to the CNS evaluation request. Limitorque concluded that the two subject valves would provide the 100 ft-lb starting torque and the motors are suitable for operation at 175°F. Limitorque specified that their experience indicated that a transient condition of 296°F for 10 seconds will not substantially change standard torque conditions. However, equipment qualification data curves indicate that the drywell temperature during a loss of coolant accident would exceed 175°F for about 15 minutes. The inspector was informed that NPPD engineering has not completed their evaluation of the limitorque response. This item will remain open pending completion of the NPPD engineering evaluation and designated corrective actions.

No violations or deviations were identified.

9. Licensee Action in Response to NRC Bulletin 88-07 (TI 2515/99)

The purpose of this portion of the inspection was to verify that the licensee has successfully completed the actions requested in NRC Bulletin 88-07, "Power Oscillations in Boiling Water Reactors."

The inspector reviewed NPPD Letters NLS 8800450 dated September 15, 1988, and NLS 8900096 dated February 28, 1989, which responded to the bulletin. The inspector determined that the responses were adequate and satisfactorily addressed all requirements of the bulletin.

The licensee generated Abnormal Procedure (AP) 2.4.1.6, "Abnormal Neutron Flux Oscillations or Operation in the Instability Region," Revision 0, dated January 27, 1989, to address responses to abnormal neutron flux oscillations. The inspector reviewed the procedure and determined that the procedure adequately addressed all concerns of the bulletin.

The inspector interviewed two senior reactor operators (SRO), two reactor operators (RO), and one shift technical assistant. The inspector determined that all personnel interviewed had received training on the event at LaSalle Unit 2, described in the bulletin, and had a full understanding of the significance of operation in the instability region. The inspector walked through an oscillation event with one RO and one SRO. Both operators were aware of the symptoms of the event and of immediate actions required. Both operators knew which procedure directed appropriate actions and were able to describe and simulate appropriate actions in accordance with AP 2.4.1.6.

No violations or deviations were identified in this area. The licensee responded promptly and adequately to the concerns of the bulletin. The operators demonstrated a thorough understanding of operations in the instability regions. NRC Bulletin 88-07 and Temporary Instruction 2515/99 are considered closed.

10. Followup on NRC Information Notices (IN) (92701)

The inspector reviewed CNS followup actions relating to NRC IN 88-035. The IN was processed in accordance with procedures and routed properly.

Resultant actions were timely and adequate. Based on this review, IN 88-035 is considered closed.

No violations or deviations were identified in this area.

11. Exit Interview (30703)

An exit interview was conducted on October 4, 1989, with licensee representatives identified in paragraph 1. During this interview, the inspectors reviewed the scope and findings of the inspection. Other meetings between the inspectors and licensee management were held periodically during the inspection period to discuss identified concerns. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.