ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket No.:	50-298
License No.:	DPR-46
Report No.:	50-298/97-06
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
Dates:	May 18 through June 28, 1997
Inspectors:	Mary Miller, Senior Resident Inspector Chris Skinner, Resident Inspector Anthony T. Gody, Senior Resident Inspector Tom Meadows, Reactor Inspector Steve Burton, Resident Inspector, Arkansas Nuclear One
Approved By:	Elmo Collins, Chief, Project Branch C
Attachment:	Supplemental Information

EXECUTIVE SUMMARY

Cooper Nuclear Station
NRC Inspection Report 50-298/97-06

Operations

- The inspector identified that the licensee approved an instant non-intent procedure change that moved the initial jet pump operability determination to after the mode switch was placed in the startup position contrary to plant Technical Specifications. Plant management demonstrated a lack of understanding of Technical Specification requirements (Section O1.2).

- The licensee found increasing unidentified leakage in containment and took conservative action to reduce power to fix the leak, well below the Technical Specifications limits. The licensee promptly reduced the allowed leakage rate when bypass flow to the torus was observed. The licensee requested and was granted enforcement discretion from Technical Specifications for high primary containment oxygen concentration. Inspectors concluded that procedures for inerting the primary containment were inappropriate in that they did not use the 24-inch valves. This is a violation (Section O1.3).

- The immediate control room crew response to a reactor recirculation pump lockout was appropriate. The inspectors found that the licensee did not document crew briefings and the immediate compensatory action for a feed pump trip (Section O1.4).

- The inspector identified a lack of procedures requiring corrective lenses appropriate for self-contained breathing apparatus (SCBAs) use by licensed operators. Nevertheless, the licensee identified that all licensed operators had the proper corrective lenses (Section O3.1).

- The inspector found that the licensee did not implement turnover checklists which listed critical parameters and specific components. Turnover checklists to verify that safety components are properly aligned are required by NUREG-0578. The licensee initiated switch checks and control board walkdowns. This item is unresolved (Section O3.2).

Maintenance

- Instrument and control technicians performed jet pump flow calibration in accordance with approved procedures. Technicians demonstrated good self-checking and communications techniques during the evolution. Additionally, technicians exercised proper control for trainees while properly conducting on the job training (Section M1.3).

- The inspectors identified a potential weakness in that the surveillance procedure for automatic depressurization valve accumulator function did not provide appropriate nonconservative time tracking. The licensee agreed to revise the procedure to include better guidance (Section M1.4).

- The licensee did not have clear ownership, or a process in place to control plant regulator settings and setpoints, resulting in reactive response to undesirable system pressures during startup activities. Ownership of the plant regulator settings was ambiguous (Section M4.1).

Engineering

- Reactor engineering demonstrated a questioning attitude in identifying a lack of documentation and understanding regarding the basis for rod groups. No procedure documented reactor engineering expectations (Section E1.1).

Plant Support

- The licensee demonstrated weak ownership in maintaining the material condition of the alternate Operations Support Center ventilation status panel and system walkdowns and rounds of emergency response facilities (Section P2.1).

- Inspectors identified that, during emergency drills, emergency planning did not verify that emergency responders had proper lenses for SCBA use (Section O3.1).

Report Details

Summary of Plant Status

The unit began this inspection period in the shutdown condition at the end of Refueling Outage 17. During this inspection period, the licensee started up the plant and ran at 100 percent power until leakage was identified in the drywell. On June 14, 1997, the licensee decreased power to 10 percent, entered the drywell, and repaired a feedwater vent line leak. The licensee then returned the unit to 100 percent power, which was maintained through the end of this inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant operations both at power and during a routine refueling outage. In particular, the inspectors observed a routine plant startup following the seventeenth refueling outage. With few exceptions, plant operations were conducted in accordance with licensee procedures, Technical Specifications, and the design bases. Noteworthy observations are discussed below.

O1.2 Routine Startup

a. Inspection Scope (71707)

The licensee performed a routine startup following the seventeenth refueling outage. In preparation, the inspectors reviewed licensee Procedure 2.1.1, "Startup Procedure," and other relevant system and operations procedures to determine if they properly implemented Technical Specification requirements. The inspectors observed the conduct of operations and management oversight throughout the plant startup.

b. Observations and Findings

The inspectors attended the shift briefing conducted by licensee management prior to the reactor startup and noted that it appropriately contained discussions about reactivity management, thoughtful deliberate conduct of operations, communications, approach of evolutions with a questioning attitude, and teamwork. Consistent with observations in previous inspection reports, operators demonstrated clear three-way communications; good attentiveness to the control boards; and slow, controlled, and deliberate equipment manipulations in accordance with the startup procedure.

The inspector observed that the licensee had difficulty obtaining good data for the daily jet pump operability check as required by Technical Specification 3.6.E. The licensee indicated that new software installed during the refueling outage did not recognize that the Loop B recirculation pump was running. The vendor-supplied software package utilized default recirculation pump amperage threshold values, to determine if a recirculation pump was running, that were higher than the actual Loop B pump amperage. Therefore, it did not recognize that both recirculation pumps were running. The jet pumps could not be declared operable until jet pump integrity could be verified.

While the problem with obtaining valid jet pump operability data was being addressed, the shift supervisor approved an "instant, non-intent" change to the startup procedure that moved the daily verification of jet pump operability requirement from Step 8.1.37 to Step 8.2.13. The inspector noted that the startup procedure required operators to complete a review of Section 8.1 prior to beginning Section 8.2. Recognizing that the daily jet pump operability check was required to be performed prior to placing the mode switch to the "startup/hot-standby" position by Technical Specifications 1.0.J, the inspector immediately questioned the operations manager, who was present observing the reactor startup, about the appropriateness of the non-intent procedure change. The procedure, if implemented as changed, would have resulted in a violation of plant Technical Specification 1.0.J, which states, in part, that entry into an operational condition or other specified condition shall not be made when the conditions for this Limiting Condition for Operation are not met, and the associated action requires a shutdown if they are not met within a specified time interval. Technical Specification 3.6.E. requires a plant shutdown if jet pumps are not made operable within 24 hours. The Operations Manager pointed out the Technical Specifications definition of "Surveillance Interval" which stated, "The surveillance interval is the calendar time between surveillance tests, checks, calibrations and examinations to be performed upon an instrument or component when it is required to be operable. These tests may be waived when the instrument, component or system is not required to be operable, but the instrument, component or system shall be tested prior to being declared operable or as practicable following its return to service." The operations manager indicated that, since the jet pumps were not required to be operable in the shutdown mode, the daily jet pump operability test could be deferred until it was practicable. The inspector informed that operations manager that this interpretation of Technical Specifications did not appear appropriate. Nevertheless, by the end of the discussion with the operations manager, the inspector noted that the daily jet pump operability check had been run and the mode switch had been placed in the "startup/hot-standby" position.

Following the discussion with the operations manager, the inspector reviewed Procedure 2.1.1 and found that the daily jet pump operability test in Step 8.2.13 was documented as being completed 2 minutes after the mode switch had been placed in the "startup/hot-standby" position. When questioned, the licensee indicated that this was an administrative error and that the jet pump operability test had been performed prior to the mode switch being placed in the startup position. The inspector reminded the licensee of the importance of maintaining accurate records that document Technical Specification surveillances.

The inspector determined that these findings were significant for several reasons: (1) the instant, non-intent procedure change required operators to place the mode switch in the "startup/hot-standby" position prior to performing the daily jet pump operability check contrary to plant Technical Specifications, (2) licensee management did not recognize that the jet pump operability was required to be verified prior to changing modes, and (3) had the procedure change been subject to a 10 CFR 50.59 screening, it should not have been allowed because it involved a procedure change affecting plant Technical Specifications. The instant, non-intent procedure change was determined to be inappropriate. This is a violation of 10 CFR Part 50, Appendix B, Criterion V (Violation 50/298-97006-01).

c. <u>Conclusions</u>

Other than the inspector identified violation, the startup was conducted well and in accordance with procedures. The instant, non-intent procedure change which moved the initial jet pump operability determination to after the mode change was inappropriate, because it resulted in not meeting plant Technical Specifications. Licensee management failed to implement the Technical Specification requirements properly.

O1.3 <u>Correction of Leakage in Containment Requiring Notice of Enforcement Discretion (EA 97-322)</u>

a. <u>Inspection Scope (93702)</u>

The inspectors reviewed the licensee's actions during the evaluation and correction of increased unidentified drywell leakage. The inspectors attended the licensee's meetings on this subject, participated in the Notice of Enforcement Discretion (NOED) process, and held discussions with the licensee's management and staff.

b. <u>Observations and Findings</u>

On June 14, 1997, the licensee requested enforcement discretion from Technical Specification 3.7.A.5. for a period of 24 hours from June 14, 9:29 p.m. through June 15, 9:29 p.m. Technical Specification 3.7.A.5 involves maintaining the oxygen concentration level in the primary containment less than 4 percent and requires a plant shutdown if the oxygen concentration becomes greater than 4 percent.

On June 5, the licensee concluded that unidentified leakage in the drywell was 0.317 gallons per minute (gpm) and increasing, but was below the Technical Specification 3.6.C. limit of 5 gpm. On June 10, the licensee utilized cameras installed in primary containment to identify that a portion of the leakage was bypassing the sump by traveling along the outside of a relief valve tailpipe downcomer into the torus. As a result, some of the leakage was not being accounted for in the unidentified leakage rate. The licensee implemented a 2.5 gpm unidentified leakage rate limit to account for this bypass flow. The inspectors considered this limit appropriate and conservative.

In a June 13 teleconference with the NRC, the licensee discussed plans to make the necessary repair and the possibility of a need to request enforcement discretion. During the teleconference, the licensee stated that emergency procedures were in place to quickly reinert primary containment. The licensee later determined this statement to be incorrect. Although an emergency system for maintaining the nitrogen level in primary containment was installed, this system (standby nitrogen injection) was not designed to be capable of reinerting from high oxygen levels.

On June 13, the licensee decreased power and deinerted. Oxygen concentration rose above 4 percent by 9:29 pm. At that time the unidentified leakage rate measured by the drywell sump was 0.417 gpm. On June 14, the licensee made an entry into primary containment at 11 percent power and determined that the source of the leakage was through the valve seats of Reactor Feedwater Line A Vent Valves RF-V-740 and -741. The vent line terminated with a quick disconnect fitting as depicted on controlled drawings, versus a plug or cap. Maintenance technicians removed the quick disconnect fitting and installed a plug which stopped the leakage. To ensure against leakage on counterpart valves on Reactor Feedwater Line B, a plug was installed in the Line B vent, although no leakage was identified from that location. The licensee stated that these valves have a history of seat bypass leakage.

At 9:05 a.m., on June 14, the primary containment inerting process began with the torus. At 9:18 a.m., 1 of the 12 drywell-to-torus vacuum breakers opened for 7 minutes because of excessive purge rates while inerting. This was considered an unplanned engineered safety feature actuation and was appropriately reported to the NRC. Because of the difference in capacity between the 24-inch purge (supply) and the 2-inch bypass (vent) piping, operators had been tasked to closely watch the purge rate in order to avoid opening the drywell-to-torus vacuum breakers. The licensee's immediate corrective actions appeared appropriate.

On June 14, the licensee and the NRC held a second teleconference, in which the licensee asked for enforcement discretion from Technical Specification 3.7.A.5 for 24 hours, in addition to the 24-hour time limit of the Technical Specification, to extend the time allowed for operating the plant with oxygen concentration greater than 4 percent. NOED 97-4-001 was verbally granted and a letter to the licensee was issued on June 18. The licensee's submittal, dated June 14, 1997, addressing the low safety significance of this operational condition, discussed the fact that the NRC had reviewed improved Technical Specifications and approved operation below 15 percent power with primary containment oxygen concentration greater than 4 percent for an indefinite period. The letter stated, "while the enforcement discretion is in effect, or until primary containment oxygen concentration is brought to less than 4 percent, the District will maintain reactor thermal power less than

15 percent." At the time of the teleconference when the NOED was verbally approved, reactor power was 18 percent and was not reduced to less than 15 percent until 2:12 p.m. Although plant Technical Specifications did not require reactor power to be less than 15 percent, the licensee's letter stated that they would maintain reactor power less than 15 percent when oxygen concentration was greater than 4 percent. The inspectors questioned the licensee about their decision to allow reactor power to remain above 15 percent several hours after the staff approved the NOED. The licensee indicated that they intended to reduce reactor power to less than 15 percent before implementing the NOED and agreed to be more clear in their communications with the NRC, particularly when it involved a regulatory decision.

The re-inerting process, using the 2-inch vent pipe, reduced the torus oxygen concentration from about 25 to 19 percent over a 5-hour period. At 2:22 p.m., a procedure change was approved that allowed the operators to use the 24-inch vent. Using the 24-inch vent, the oxygen dilution rate was significantly increased and torus oxygen concentration was reduced from about 19 to 4 percent over a 4.5-hour period. At 11:59 p.m., the oxygen concentration within primary containment (torus and drywell) was less than 4 percent and the Technical Specification was exited. The licensee indicated that, had the 24-inch vent been approved before beginning the re-inerting process, primary containment would have been capable of being re-inerted prior to the expiration of the Technical Specification Limiting Condition of Operation at 9:29 p.m. on June 14, making implementation of the NOED unnecessary. The inspectors reviewed the primary containment oxygen concentration data and concluded that the licensee was correct.

The failure to have a reviewed and approved procedure for using the 24-inch vent during re-inerting appeared to result in not being able to re-inert the primary containment prior to the expiration of the Technical Specification Limiting Condition of Operation. The inspector also noted that, had the 24-inch vent been available, the engineered safety features actuation would most likely not have occurred. Therefore, the re-inerting procedure was not appropriate for the operating circumstances and is a second example of a violation of 10 CFR Part 50, Appendix B, Criterion V (Violation 50-298/97006-01)(EA 97-322).

c. Conclusions

The licensee found increasing unidentified leakage in containment, and took conservative action to reduce power to fix the leak and deinert the primary containment, well below the Technical Specification leakage limits. The installation and use of cameras inside primary containment was considered a strength. The licensee requested and was granted enforcement discretion from Technical Specifications for high primary containment oxygen concentration. In accordance with the NRC policy on NOEDs, the inspectors reviewed all the circumstances surrounding the need for an NOED and found the reinerting procedure to be inadequate. The inadequate procedure also appeared to contribute to an unplanned engineered safety feature actuation during the initial phases of reinerting.

O1.4 Lack of Documentation of Significant Activities and Immediate Compensatory Action Instructions

a. Inspection Scope (71707)

The inspector reviewed documentation and compensatory actions associated with a lock-out of a reactor recirculation pump speed controller.

b. Observations and Findings

On June 25, 1997, at approximately 2:30 a.m., a lock-out of the Reactor Recirculation Motor Generator B Set speed controller occurred. When the inspector was notified by telephone at 3 a.m., the inspector questioned if the operations crew had evaluated their response to a feedwater pump trip with the recirculation motor generator set in locked-out configuration. The inspector noted that this scenario could result in an automatic runback of one recirculation pump, but no change in the speed of the locked-out recirculation pump. The resulting reactor power and flow would place reactor operations in or near the instability zone. When the inspector arrived in the control room at 5 a.m., the shift supervisor noted that the shift crew had been instructed to trip the reactor if a feed pump trip were to occur to avoid operation in the instability zone. The inspector noted that neither these compensatory actions to trip the plant, nor the crew briefings, had been documented in the control room logs or in other documentation. The crew was knowledgeable of the compensatory actions.

The inspector observed the crew turnover which provided verbal instruction to the oncoming crew, of the configuration of the locked-out recirculation pump, and the need to trip the plant if a feedwater pump trip were to occur. The inspector noted that no additional documentation of this compensatory action or the crew briefing had occurred and raised the concern of lack of documentation to licensee management. About 10 a.m., the licensee put a night order in place requiring that the reactor be tripped immediately if a single feed pump trip were to occur, in order to avoid operation in the instability zone. A procedure change was also made to incorporate the compensatory actions.

Quality Assurance Emergency Surveillance E103-9701, dated July 1, 1997, noted that operations response actions were in accordance with approved procedures, and appropriate abnormal and operations procedures were implemented and documented. Quality Assurance concluded that the compensatory actions and surveys were conservative and appropriate, but also noted that no log entries or night orders were put in place regarding immediate compensatory actions or briefings until later.

c. Conclusions

The immediate control room crew response to a reactor recirculation pump lockout of briefing crew members addressed relevant contingencies. Inspectors identified that the licensee's documentation of the crew briefings and the immediate compensatory actions for a feed pump trip was not timely.

O2 Operational Status of Facilities and Equipment

O2.1 Shift Communicator Procedure Not Properly Implemented for Nonemergency Reports

a. Inspection Scope (71707)

The inspectors compared plant operations shift crew procedures with observed practices.

b. Observations and Findings

On June 6, 1997, during a review of operations shift crew procedures, inspectors noted that Procedure 2.0.5, Revision 14, "Reports to NRC Operations Center," stated in Step 8.1 that the shift communicator would communicate 10 CFR 50.72 reports to the NRC Headquarters Operations Center. Inspectors noted that more than 8 of the 50.72 reports received in the past 2 years were performed by either the Shift Supervisor or the Shift Technical Advisor. When questioned by the inspectors, the licensee stated that the shift communicator duties were assigned in accordance with administrative instruction operations department expectations dated March 24, 1997, Attachment U, which stated that the shift communicator will be the reactor building station operator for all events except for fires. The licensee revised Procedure 2.0.5 on June 26, 1997, to reflect the option that other members of the shift crew could inform the NRC of 10 CFR 50.72 reports.

c. Conclusions

The inspectors identified an inconsistent implementation of procedures governing licensee management expectations in that operations procedures and instructions designated a different crew position for communicating NRC nonemergency reports than the shift technical advisor and shift supervisor, who had routinely performed the notification. The inspector concluded that the practice of not following procedures, in this case, procedures implementing expectations, was an example of a potential program weakness. The licensee took immediate actions to correct the procedure problem and re-emphasized the management expectation that procedures be followed or corrected.

O3 Operations Procedures and Documentation

O3.1 Failure to Require Corrective Lenses Appropriate for SCBA Use

a. Inspection Scope (71707)

The inspector reviewed program controls regarding the plant staff having proper corrective lenses for use with SCBAs.

b. Observations and Findings

On June 23, 1997, the inspector asked the licensee if corrective lenses designed for use with SCBAs were available for personnel requiring corrective lenses. The inspector noted that no procedural controls for SCBA corrective lenses were in place. The licensee indicated that the operations training program placed heavy emphasis on operators obtaining proper corrective lenses for use with SCBAs, and procedural controls were most likely not necessary to have an effective program. On June 27, the licensee stated that they would verify that licensed operators had corrective lenses for use with SCBAs. On June 30, the licensee identified that an auxiliary operator did not own corrective lenses appropriate for SCBA use. No problem identification report was initiated to document this finding. After discussions with inspectors concerning the lack of a program for this concern, the licensee issued Problem Identification Report CAQ 97-1235. On July 1, the licensee had checked two operations crews and found that those licensed operators had appropriate SCBA lenses. The licensee stated that no licensed operator would assume watch without required corrective lenses appropriate for use with SCBAs. On July 11, the licensee confirmed the only operations staff member found without proper lenses was the individual noted on June 30.

During a licensee emergency drill, the inspectors noted that corrective lenses appropriate for SCBA use by emergency responders were not verified. The licensee agreed to address that issue as part of their problem identification report.

c. Conclusions

The inspector identified that no procedures were in place to require corrective lenses appropriate for SCBA used by licensed operators or for those individuals such as auxiliary operators or emergency responders. Nevertheless, the licensee's instructions and qualifications for operators was successful in assuring that corrective lenses were available, as evidenced by the fact that all licensed operators had lenses available.

O3.2 Failure to Provide Operations Checklist for Component Verification for Shift Turnovers

a. Inspection Scope (71707)

The inspectors reviewed the licensee's implementation of the operations shift turnover checklist described by NUREG-0578, "TMI-2 Lessons Learned Task Force Report."

b. Observations and Findings

On January 2, 1980, the NRC issued a "show cause" order which required the licensee to provide control room turnover checklists as described in NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short Term Recommendations." NUREG-0578 indicated that these checklists were for use by operators at turnover to verify safety components were properly aligned and critical parameters were properly checked. On January 11, 1980, the licensee stated that these checklists would be implemented. In April of 1980, the licensee indicated that they had implemented checklists for review of specific component alignment during turnovers.

The inspectors found that the turnover checklists did not list the critical parameters or specific plant components to check in the control room, which was inconsistent with the requirements described in NUREG 0578. In response to this concern, on June 2, 1997, the licensee initiated a night order requiring switch checks and control board walkdowns early in each shift. In addition, the licensee initiated actions to develop shift turnover checklists in accordance with the subject order and NUREG-0578.

The inspectors planned to review both the enforcement aspects of this issue and the licensee's corrective actions as the resolution of an unresolved item. (Unresolved Item 50-298/97006-02).

c. Conclusions

The inspector identified that the licensee did not implement checklists to verify control room indications during turnovers as described in NUREG-0578.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) Violation 50-298/96007-02: The inspector reviewed the licensee's response letter, NLS960136, dated July 22, 1996, and related condition reports regarding a violation of 10 CFR Part 50, Appendix B, Criterion V. The licensee made an on-the-spot change to a design change. The original design change modified a diesel generator by removing the muffler bypass valve. The on-the-spot change stated operations could declare the diesel operable, although inspectors identified on

March 15, 1996, that postmodification testing was not completed, a section of the essential exhaust path was suspended by chain falls rather than supports, and a valve in that section was removed, resulting in a pipe opening which was not evaluated. This was a violation of Procedure 3.4.10, "Station Modification Changes." The inspector reviewed the corrective action taken by the licensee to prevent a recurrence of this violation. The corrective actions included completing the postmodification testing before declaring the diesel operable, counseling associated personnel, and developing Operating Instruction 16 to provide operational guidance for returning safety systems to operable status. The inspector determined that the licensee's actions were adequate and closed this violation.

O8.2 (Closed) Violation 50-298/96023-06: The inspector reviewed the licensee's response letter, NLS960196, dated October 30, 1996, and related condition reports regarding multiple violations of 10 CFR Part 50, Appendix B, Criterion V. This violation was issued because operators failed to notify the control room supervisor and shift supervisor of a mispositioned control rod per Procedure 2.0.3, "Conduct of Operations," on January 7, 1996. The inspector reviewed the corrective actions taken by the licensee to prevent a recurrence of this violation. The corrective actions included removing the crew from license duties on January 8, 1996, pending assessment and evaluation of the event, taking disciplinary action against both reactor operators, and initiating an independent investigation review team. The licensee also had a station stand-down on January 16, 1996, to discuss these issues and other items important to safety. The licensee determined the root cause to be attributed to the operators involved. The inspector determined that the licensee's actions were adequate and closed this violation.

O8.3 (Closed) Violation 50-298/96023-07: The inspector reviewed the licensee's response letter, NLS960196, dated October 30, 1996, and related condition reports regarding multiple violations of 10 CFR Part 50, Appendix B, Criterion V. This violation was issued because, on January 7, 1996, operators deviated from the approved rod sequence plant procedure without the approval of a reactor engineer or a Station Operations Review Committee, required by Procedure 10.13, "Control Rod Sequence and Movement Control." The inspector reviewed the corrective actions taken by the licensee to prevent a recurrence of this violation. The corrective actions included developing written management expectations of the roles and responsibilities of the reactor operator and second checker during control rod manipulations and developing Operations Instruction 7 to provide additional guidance on concurrent verification. The licensee also initiated a station stand-down on January 16, 1996, to discuss these issues and other items important to safety. The licensee determined the root cause to be attributed to personnel error. The inspector determined that the licensee's actions were adequate and closed this violation.

O8.4 (Closed) Violation 50-298/96023-08: The inspector reviewed the licensee's response letter, NLS960196, dated October 30, 1996, and related condition reports regarding multiple violations of 10 CFR Part 50, Appendix B, Criterion V. This violation was issued because operators failed to implement a recovery plan for recovering mispositioned control rods with concurrence of the shift supervisor and reactor engineering, per Procedure 10.13, "Control Rod Sequence and Movement Control," on January 7, 1996. The inspector reviewed the corrective actions taken by the licensee to prevent recurrence of this violation. The corrective actions included taking disciplinary actions against the two reactor operators that were involved. The requirements for compliance were discussed with operations personnel to ensure a common understanding of Procedure 10.13. The licensee also initiated a station stand-down on January 16, 1996, to discuss these issues and other items important to safety. The licensee determined the root cause to be attributed to operator misconduct. The inspector determined that the licensee's actions were adequate and closed this violation.

O8.5 (Closed) Violation 50-298/96025-01: Technical Specification 6.2.1.A.4.e. requires a review of station operation by the Station Operations Review Committee so potential nuclear safety hazards could be detected. However, it was determined that from July 2 through November 25, 1996, the Station Operations Review Committee did not review station operations for potential safety hazards. The inspector reviewed the corrective action taken by the licensee to prevent recurrence of this violation. The corrective actions included a revision of implementing Procedure 0.3, "Station Operations Review Committee," clarifying duties in this area. The licensee also initiated a station stand-down on April 5, 1997, to discuss this issue and other items important to safety. The inspectors have since observed appropriate reviews of potential safety hazards by the Station Operations Review Committee. The inspector determined that the licensee's actions were adequate and closed this violation.

O8.6 (Closed) Inspection Follow-up Item 97002-01: Procedure for Disabling Annunciators. Inspectors had noted that operations shift crew disabling of annunciators was controlled by instructions which did not require review of the Updated Safety Analysis Report or abnormal procedure requirements to ensure the plant configuration was not compromised with respect to these references. The licensee acknowledged that the annunciator disabling procedure was weak and stated that formal procedure controls for annunciator disabling would be implemented. The inspector had noted no safety issues associated with the previous process as it was implemented over a 10-month period.

On June 6, 1997, the inspector completed review of Procedure 2.3.1, Revision 16, "General Alarm Procedure." This procedure had been revised to include a disabled annunciator evaluation process requiring evaluation of alarms with respect to operability assessments, abnormal, emergency, emergency operating procedures, and emergency plant implementing procedures, and Technical Specification surveillance criteria. The procedure required that monitoring and compensatory actions be evaluated and recorded. The procedure provided a table which identified alarms called out in surveillance procedures, Technical Specifications, and the Updated Safety Analysis Report. Based on a sample inspection of alarms, the inspector found that, in general, the procedure properly identified alarms which were credited for those controlled procedures and plant configuration requirements. The inspector observed a significantly increased level of rigor in the process for disabling annunciators. This procedure improvement addressed the inspectors' concern.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726 and 62707)

The inspectors observed all or portions of the following work activities:

Procedure	Title
14.15.1	Jet Pump Flow Calibration
6.ADS.302	Automatic Depressurization System (ADS) Accumulator Test
6.ADS.202	ADS Manual Valve Actuation From Alternate Shutdown Panel
MWR-97-0563	Replace Leaking Valve on ADS Accumulator

M1.2 Jet Pump Flow Instrument Calibration

a. Inspection Scope (61726)

On June 18, 1997, the inspectors observed the calibration of one channel of reactor jet pump flow instrumentation. Included in this observation was a review of the procedure requirements, instrument and control technician knowledge, training methodologies used for on-the-job training performed for two technicians, and equipment calibration.

b. Observations and Findings

The inspectors observed instrument and control technicians perform portions of Procedure 14.15.1, Revision 7.2, "Jet Pump Flow Calibration." The inspectors observed the initial venting and test rig installation in the reactor building as well as instrument checks performed in the control room. Technicians were conducting on-the-job training for two unqualified technicians during the performance of calibration. All of the technicians were knowledgeable of the procedural requirements. Good face-to-face and phone communications were observed. Technicians utilized good self-checking techniques. The qualified technicians closely monitored trainee performance throughout the procedure. Instrumentation used for the performance of the procedure was within calibration dates. Technicians adhered to the procedure and signed for each step upon completion.

c. Conclusions

Instrument and control technicians performed jet pump flow calibration in accordance with approved procedures. Technicians demonstrated good self-checking and communications techniques during the evolution. Additionally, technicians exercised proper control of trainees while properly conducting on-the-job training.

M1.3 ADS Accumulator Test

a. Inspection Scope (61726)

The inspectors observed testing of the ADS accumulators and held discussions with the maintenance technicians and a maintenance supervisor.

b. Observations and Findings

On May 13, 1997, the inspectors observed the performance of Procedure 6.ADS.302, "ADS Accumulator Functional Test," Revision 2, which verified that the accumulators retained required air pressure after 1 hour. The acceptance criterion for remaining pressure was based on that sufficient to actuate the ADS relief valves five times.

The inspectors noted a procedural weakness in that the procedure did not provide guidance on how the 1-hour time limit should be tracked. The maintenance technicians noted the time prior to performing any steps in the procedure, entered the drywell, and established the desired initial accumulator pressures by traveling about the drywell from one accumulator to the next. The maintenance technicians waited 1 hour from the start time and then performed the procedural steps to check the accumulator pressures, again traveling from one accumulator to the next in the same order as the test initiation. No times were checked other than the single start and finish times. The inspectors noted that tracking the 1-hour time limit in this manner could lead to a nonconservative error with regard to the time limit.

During this surveillance observation the inspectors did not identify any nonconservative implementation regarding the 1-hour time limit for each accumulator. After discussions with the licensee, the licensee agreed that the procedure should be revised to provide better guidance to the maintenance technicians on how to track the 1-hour time limit. The licensee issued a problem identification report to revise the procedure.

c. Conclusions

The inspectors identified a potential weakness in that the surveillance procedure for automatic depressurization valve accumulator function did not provide appropriate guidance on how to track the 1-hour time limit. The method used was vulnerable to nonconservative time tracking. The licensee agreed to revise the procedure to include better guidance.

M4 Maintenance Staff Knowledge and Performance

M4.1 Control of Plant Process Regulators

a. Inspection Scope (62707)

The inspectors evaluated problems caused by improper regulator settings during the reactor plant startup.

b. Observations and Findings

The inspectors noted that, during the plant startup, a number of operational difficulties were caused by improper regulator settings. The high pressure coolant injection (HPCI) lubricating oil pressure regulator was found set below its band during its first surveillance test on May 22, 1997. Plant evaluation determined that the installed oil pressure gauge had been used to set the regulator. Further, on May 23, the main turbine generator unit gland seal flow hydrogen cooling was inadequate as a result of an improperly set regulator. On May 24, the Automatic Depressurization System Accumulator Low Pressure Alarm actuated, indicating inadequate nitrogen pressure. Operators found the nitrogen pressure regulator which supplies nitrogen to the accumulators was set too low. On June 3, operators noted difficulties with main turbine gland sealing regulating valves.

Inspectors questioned whether processes for determining and setting regulators were adequate. Inspectors also questioned if the use of installed plant equipment for measuring and test equipment purposes was properly managed to ensure calibration accountability.

Interviews with maintenance and operations personnel indicated that multiple organizations set and maintained the various regulators. Responsibility for regulator setting was not clearly delineated. The licensee stated that a review of regulator requirements and plant processes would be done to better anticipate and control regulator settings.

The licensee found that the HPCI oil pressure gage had last been set several months prior and had drifted to the edge of its band. The inspectors noted that the applicable problem identification report review was addressing only the HPCI pressure issue, and did not address the measuring and test equipment control concerns with respect to use of installed plant gages. In response to this concern, the licensee agreed the use of installed gages as measuring and test equipment should be evaluated.

c. Conclusions

The licensee did not have clear ownership, or a process in place to control plant regulator settings and setpoints, resulting in reactive response to undesirable system pressures during startup activities. Ownership of the plant regulator settings was ambiguous.

M8 Miscellaneous Maintenance Issues (92700) (92902)

M8.1 (Closed) License Event Report 50-298/96011: A technician found one nut finger loose on the split coupler connecting the HPCI stop valve with its operator. The licensee found that coupling fasteners were wrench tightened during reassembly without a specific torque value. The licensee revised HPCI system maintenance procedures that affected the coupling to incorporate guidance for appropriate coupling fastener torquing. The licensee also reviewed generic valve procedures and system operating procedures to ensure that sufficient guidance for tightening split couplings was provided. The inspector determined that the licensee's actions were adequate. The failure to include torquing instructions in the maintenance procedure, resulting in a safety system being inoperable, is a violation of 10 CFR Part 50, Appendix B, Criterion V, which requires, in part, procedures or instructions appropriate to the circumstance shall be implemented. This nonrepetitive, licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (Noncited Violation 50-298/97006-03).

M8.2 (Closed) Violation 50-298/96019-02: The inspector reviewed the licensee's response letter, NLS960206, dated November 6, 1996, and related problem identification reports regarding two violations of 10 CFR Part 50, Appendix B, Criterion V. Inspectors identified that the licensee had declared the HPCI system operable without removing the lanyard potentiometer from the stop valve as required. Also, on August 29, 1996, inspectors identified that Procedure 7.2.53.7, "Operation of Engine Analysis," did not adequately control the installation of test equipment on the diesel generator even though the procedure stated that test equipment should only be installed while the diesel generator is in an allowed outage time or is not required to be operable. Inspectors identified that the diesel generator was returned to operable status with test equipment installed. The inspector reviewed the corrective action taken by the licensee to prevent recurrence of this violation. The corrective actions included an evaluation that concluded for both of the system configurations, neither situation adversely affected component or system reliability, that Procedure 7.2.53.7 was revised to ensure that the control room staff is aware when the diesel generator testing equipment has been installed, and the licensee's surveillance test procedures were reviewed and edited as necessary to ensure that the installation and removal of test equipment is performed consistently with operability requirements. The inspector determined that the licensee's actions were adequate and closed this violation.

M8.3 (Open) Violation 50-298/94016-02: Failure to implement Technical Specification surveillance requirements. During review of corrective actions for this violation, the inspectors identified that many surveillance steps intended to verify Technical Specification acceptance criteria were written in a manner that did not require verification. In these cases, the licensee had used the term "ensure" rather than "verify," which, by this licensee's definition, means that, if the required response is not observed, the operator is to promptly adjust plant equipment to obtain the response. This finding was documented in an earlier report. The licensee responded on June 4 with a night order to provide expectations for the word "ensure" used in surveillance procedures. It was to be interpreted as "verify" where acceptance criteria were concerned. On June 25, the licensee changed four surveillance procedures. The night order was still in place, and licensee reviews were continuing.

The licensee was continuing a validation of the Surveillance Test Verification Program to address multiple concerns raised by the inspectors. Inspector followup will resume when the licensee's corrective actions are more complete.

III. Engineering

E1 Conduct of Engineering

E1.1 Lack of Understanding of Rod Pattern Differences from Banked Position Withdrawal Sequence (BPWS)

a. Inspection Scope (37550, 37551)

Inspectors reviewed licensee actions associated with a difference between actual rod pattern and vendor reference documentation. Inspectors reviewed associated documents and discussed actions with licensee staff.

b. Observations and Findings

On May 30, 1997, reactor engineering identified that the banked position withdrawal sequence for the control rods had not been implemented consistent with the positions documented in NEDO-21231, 1977, "Banked Position Withdrawal Sequence." This document prescribes which rods are to be assigned to which withdrawal groups. A contract engineer questioned why the groups being used by the licensee for rod control were different from those specified in the vendor reference document.

On May 30, the licensee initiated Problem Identification Report (PIR) 2-23052, which identified that control rod group assignments do not meet the BPWS sequence. The BPWS ensures that incremental control rod worths are maintained at low values. This is of particular importance below 20 percent power. In response to this concern, the licensee promptly implemented night orders that the plant be tripped if power dropped below 20 percent. Inspectors noted that Technical Specifications required that the rod worth monitor be verified to contain correct Banked Position Withdrawal Sequence rod groups.

The NRC noted that the core reload report referenced use of the BPWS. During the review of the control rod drive housing operability support evaluation, inspectors identified that the notch-worth reactivity was considered to be bounded, based on General Electric letter dated May 15, 1997, which stated that the high negative reactivity feedback would be negligible because the licensee adheres to the BPWS for rod pattern control below the low power set point. The licensee later determined that the rod groupings currently used by the licensee had been approved by the NRC on December 22, 1992, in License Amendment 156, referencing the analysis of General Electric Service Information Letter 316, dated November 1979. This letter is referenced in the Technical Specifications and states that the licensee's assignments for rod withdrawal groups are identical to the rod sequence control system, which implements the reduced notch-worth procedure. This function was later described in General Electric's report NEDO 21231. The NRC safety evaluation associated with Amendment 156 accepted the licensee statement that the licensee employs the Banked Position Withdrawal Sequence control rod movement pattern, which is a method that ensures control rod worths are maintained at low values.

When this was evaluated, the licensee retracted the night order and closed the problem identification report. The inspector noted that this conclusion was reasonable from an immediate safety standpoint and that reactor engineering had identified significant questions, demonstrating an improved questioning attitude.

The inspector noted that Procedure 3.2, "System Engineering Program," required that system engineers be system experts and be familiar with design and operation of the system. The reactor engineering program did not appear to have implemented this requirement with respect to the two recent issues. The licensee stated that Procedure 3.2 did not apply to reactor engineers and that reactor engineers were not controlled by procedure. The licensee stated that the engineers' training standards have been improved over the past year to comply with an industry standard on reactor engineer training.

c. Conclusions

Reactor engineering demonstrated a good questioning attitude in identifying a lack of documentation and understanding regarding the basis for rod groups. No procedure documented reactor engineer expectations.

IV. Plant Support

P2 Status of Emergency Procedure Facilities, Equipment, and Resources

P2.1 Weak Ownership of Emergency Response Facilities Ventilation Systems

a. Inspection Scope (71750)

Inspectors questioned the reasons for extinguished damper circuit lights in the Alternate Operations Support Center (OSC) during a plant walkdown and followed up with discussions with plant staff.

b. Observations and Findings

On June 6, 1997, inspectors observed that the alternate OSC ventilation indicator lights for two dampers were extinguished. The licensee replaced the light bulbs and identified that the old light bulbs had burned out. Inspectors noted that it appeared that no routine walkdown of this status panel occurred. The emergency preparedness director stated that he was not sure who was responsible for monitoring the status of this panel since the panel was located in the instrumentation and control spaces. The control room staff stated that they had not been assigned that area.

The inspector noted that the apparent lack of periodic walkdowns of the ventilation system was not being addressed during discussions. Both engineering and emergency planning staff speculated that operations performed walkdowns, which the inspector pointed out was incorrect, based on the inspector's prior discussions with operations. The emergency planning staff agreed to address this issue.

c. Conclusions

Inspectors identified weak ownership in the monitoring of the alternate OSC ventilation status panel and rounds of emergency response facilities.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the exit meeting on July 2, 1997. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. Information associated with the BPWS was considered proprietary information and was returned to the licensee and not included in this report. No additional proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Mike Bennett, Nuclear Licensing and Safety Supervisor
Mark Bohling, Senior Quality Assurance Specialist
Dan Buman, Engineering Support Manager
Paul Caudill, Safety Assessment/Site Support, Senior Manager
Fadi Diya, Design Engineering Manager
Lisa Freeman, Licensing Secretary
Chuck Gaines, Maintenance Manager
Rick Gardner, Operations Manager
Phil Graham, Vice President, Nuclear
Mike Hale, Radiation Protection Manager
Beth Hannaford, Program Engineer
W. Jay Leininger, Engineering Consultant
Ole Olson, Plant Engineering Manager
Mike Peckham, Plant Manager
Jim Pelletier, Engineering Senior Manager
Bruce Toline, Quality Assurance Audit Supervisor

INSPECTION PROCEDURES USED

IP 37550: Engineering

IP 37551: Onsite Engineering

IP 61726: Surveillance Observation

IP 62707: Maintenance Observation

IP 71707: Plant Operations

IP 71750: Plant Support Activities

IP 92901: Followup - Plant Operations

IP 92902: Followup - Maintenance

IP 92700: Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities

IP 93702: Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, OPENED AND CLOSED, CLOSED, AND DISCUSSED

Opened

298/97006-01	VIO	Failure to follow Technical Specification (Section O1.2) and Inadequate procedure for re-inerting containment (Section O1.3)
298/97006-02	URI	Turnover checklist (Section 03.2)

Closed

298/96007-02	VIO	Diesel Generator 2 inappropriately declared operable (Section O8.1)
298/96011	LER	Inoperable HPCI System due to loose nut on stop valve (Section M8.1)
298/96019-02	VIO	Inappropriate installation of test equipment on safety-equipment (Section M8.2)
298/96023-06	VIO	Failure to notify control room of mispositioned rod (Section O8.2)
298/96023-07	VIO	Failed to use approved control rod insertion sequence (Section O8.3)
298/96023-08	VIO	Control rod sequence/movement control (Section O8.4)
298/96025-01	VIO	Failure of SORC to review operations to detect hazards (Section O8.5)
298/97002-01	IFI	Review of administrative controls of disabled annunciators (Section O8.6)

Opened and Closed

298/97006-03	NCV	Inadequate procedure caused inoperable HPCI system due to loose nut on stop valve (Section M8.1)

Discussed

298/94016-02	VIO	Inadequate surveillance testing (Section M8.3)