U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	Illinois Power Company
Facility:	Clinton Power Station
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EXECUTIVE SUMMARY

Clinton Power Station
NRC Inspection Report 50-461/96009 (DRP)

This inspection included aspects of licensee operations, engineering, maintenance, and plant support.

Operations

- Operator actions in response to a process radiation monitor alarm on the "B" residual heat removal heat exchanger were performed quickly and in accordance with procedures (Section O1.2).

- A reactor water cleanup pump failed upon loss of suction flow during a bus restoration. The procedure in use allowed system operation when pump trip protective features were inoperable. A violation was identified for this concern (Section O1.3).

- Operations personnel performed well during a partial loss of control room annunciators (Section O1.4).

- Good observation by an operator resulted in the quick identification and termination of a fire in the lagging of the reactor core isolation cooling (RCIC) system turbine (Section O1.5).

- A violation was identified for failure to maintain a suppression pool temperature log during a RCIC system test as required by technical specifications (Section O1.6).

- Overall awareness of plant conditions by operations personnel was acceptable. However, the identification of two unexpected equipment indication problems was not timely. A policy was implemented of performing and documenting main control room panel walkdowns every 2 hours (Section O4.1).

- A violation was identified for crediting watch standing time for individuals in positions that did not require a license as defined in the facility's technical specifications (Section O5.1).

- The licensee's focus on maintaining an open atmosphere improved the effectiveness of fact-finding critiques (Section O7.1).

- An adverse trend in safety tagging errors was recently identified by the licensee. A violation for ineffective corrective action for repetitive tagging errors affecting the security lighting system was identified. Also, while no tagging errors resulted, inconsistencies with the safety tagging program were identified by the inspector (Section O8.1).

- Potential adverse trend in fires associated with oil soaked lagging was questioned. (Section 01.5)

- Lack of clarity, mixed understanding of the intent, and implementation of the TPD/PDR process outside of management's expectations were considered weaknesses. (Section 03.1)

- Shift Supervisor and Main Control Room Operator journals' level of detail was sparse. Management's expectations for journal entries were not clearly defined. (Section 04.1)

Maintenance

- Incorrect performance of procedural steps during emergency diesel generator testing resulted in a violation (Section M1.2).

- Overall status of the use history analysis program was poor. Analyses were not completed in a timely manner and corrective actions to resolve previous timeliness problems were not being performed. A violation was identified for these concerns. Also, an inspection followup item was identified for EDG synchronization check relay problems (Section M2.1).

- Minor attention to detail problems were noted during a review of the 125 volt DC battery service test results (Section M3.1).

Engineering

- A lack of engineering rigor was demonstrated when a review of an operability determination for the MSIV leakage control system failed to identify that the supporting data was inconsistent (Section E1.1).

- Resolution of recent RCIC turbine lube oil issues was untimely. In addition, the licensee's technical evaluation of the issue lacked conservatism (Section E1.2).

- After NRC questioning of the results and methodology of local leak rate testing of feedwater check valves, the licensee identified that the methodology provided invalid results. Apparent violations were identified regarding repetitive feedwater check valve test failures and test methodology. An extensive modification development project was initiated to address poor check valve performance (Section E2.1).

Plant Support

- A violation was identified due to the failure to wear proper protective clothing when entering a contaminated area (Section R1.1).

- A violation was identified because information contained in emergency operating procedure EOP-08 was inconsistent with plant design and conflicted with information in the Updated Safety Analysis Report (Section R3.1).

- One example of unfamiliarity with radiation work permit requirements was identified (Section R4.1).

Report Details

Summary of Plant Status

The plant operated at 100 percent power with occasional down power to 80 percent for control rod testing until September 6 when the plant was shut down due to excessive unidentified leakage. The 6th refueling outage began on October 13 and the plant remained in refueling mode during the remainder of the inspection period. Major work activities included the replacement of all 16 safety relief valves and of 15 control rod drives, turbine tie wire brazing, feedwater check valve testing, and resolution of main control room deficiencies.

I. Operations

01 Conduct of Operations

O1.1 General Comments

Refueling activities were performed without incident until licensee management stopped all safety related work in response to the event discussed in Section O1.2. As a result, the scheduling of all remaining work was reassessed to ensure that minimal conflicts were present and that any necessary compensatory measures were in place prior to performing work. The new outage schedule extended the outage from November 14 to December 3, 1996. However due to emergent issues, the completion of the outage was extended beyond December 3. The additional time built into the new schedule permitted the performance of additional activities and allowed increased preparation time prior to performing other work items.

O1.2 Shutdown Cooling Secured in Response to Radiation Monitor Alarm

a. Inspection Scope (93702/71707)

On October 17, 1996, the licensee secured shutdown cooling due to an alarm on a service water (SX) process radiation monitor 1PR039 for the residual heat removal (RHR) heat exchanger (HX). The inspectors reviewed the actions taken in response to the event and the use of the following procedures:

- CPS 7410.10, "Investigation of AR/PR annunciator alarms"
- CPS 4979.05, "Abnormal Release of Radioactive Liquid"
- CPS 3303.01, "Reactor Water Cleanup"
- CPS 3312.01, "Residual Heat Removal"
- CPS 4006.01, "Loss of Shutdown Cooling"

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

At 3:00 a.m., the radiation protection (RP) staff received an alarm on process radiation monitor 1PR039. RP personnel immediately entered CPS 7410.10 and determined that the monitor had been just below the setpoint for approximately 20 minutes prior to the alarm being received (the monitor does not alarm until a reading above the setpoint is achieved). Approximately five minutes later, the control room was notified of the above condition.

The control room operators implemented CPS 4979.05 and began actions to isolate the SX supply to the RHR "B" HX. A grab sample was taken in order to determine the radioactivity source and validate the alarm.

Although the indication provided by 1PR039 returned to normal levels at 3:12 a.m., all departments involved continued to perform required actions. Discussions between the shift supervisor, the assistant shift supervisor, and the RP staff concluded that the alarm was valid and the SX supply to the HX was isolated to prevent any possible radioactive discharge to the lake. Technical specification (TS) 3.9.9 was also entered due to securing shutdown cooling.

A conscious decision was made to continue operating the "B" RHR pump to enhance circulation through the core. In addition, the reactor water cleanup (RT) system was in operation both prior to and during the event. As required by TS, the operators verified the availability of an alternate method of decay heat removal (the reactor water cleanup system) within one hour. During this time, the control room also entered the loss of shutdown cooling off-normal procedure. Using this procedure, the operators maximized the cooling capabilities of the RT system by bypassing the regenerative HX.

At 4:21 a.m., chemistry reported that the sample from 1PR039 contained only natural background radiation. It was believed that the levels of natural background had increased due to a thunderstorm in the area (increased background radiation is common following storms). Once acceptable chemistry results were obtained, SX was restored to the RHR HX and the "B" RHR train was placed back in shutdown cooling. The increase in reactor coolant temperature was approximately 9°F.

The RHR "A" HX was considered available to provide cooling during this time; however, integrated testing for that division was in progress. The test procedure contained no guidance on how to exit the procedure should RHR "A" be needed for shutdown cooling. The testing also had the potential of losing the water fill for the RHR system. In addition, feed water check valve testing was in progress and using RHR "A" would have required the injection by an alternate path (which was proceduralized). All these issues raised questions on how long it would take to realign RHR "A" to shutdown cooling. The licensee decided to restore the system to operable status and discontinue the integrated testing. During the realignment process, miscommunications occurred between operations and radiation protection (RP) which resulted in some questionable RP practices (see inspection report 96012).

c. Conclusions

Operations personnel responded appropriately to the event and all actions were performed in accordance with approved procedures. Initially good coordination between radiation protection and operations personnel was noted. Subsequent communications were not effective.

O1.3 Inservice Failure of Reactor Water Cleanup Pump

a. Inspection Scope (71707)

The inspector conducted a review of the facts surrounding the in-service failure of the "C" reactor water clean-up (RT) pump (1G33C001C). The pump failed as Operators were performing procedure CPS No. 3509.01C001, "Division I Nuclear System Protective System (NSPS) Bus Outage Checklist," which required the pump trip protective features to be removed from the logic circuit.

b. Observations and Findings

On October 29 and 30, a procedure was utilized as part of the Division I Nuclear System Protection System (NSPS) outage which did not adequately protect other plant equipment. Plant operators were attempting to restore the Division I NSPS Bus following a planned bus outage using CPS No. 3509.01C001. This procedure contained an impact assessment on plant systems which may be affected and stated that various safety system actuations (including a Group 4 Isolation, which included the RT System) may result during the performance of the procedure.

Performing this bus outage while leaving the RT system in-service required the breaker for the outboard containment isolation/pump suction valve (1G33-F004) to be opened. This action precluded the valve from closing if a containment isolation signal was generated during the performance of the test. In addition, a jumper was installed in panel 1H13-P613, which removed pump trip protection in the event this valve was less than full open. Performing this bus outage also required the removal of fuse G33AF4 in panel 1H13-P613, which disabled the RT pump low flow (suction pressure) trip. Basically, while in this configuration, the RT pumps had no trip protection in the event suction flow was interrupted. The procedure was written to allow RT system operation while the associated logic buses were de-energized.

Procedure CPS No. 3509.01C001 was properly implemented to de-energize and restore the Division I NSPS Bus. The restoration portion of the procedure required closing the breaker which powered the outboard containment isolation/pump suction isolation valve (1G33-F004) (section B, step 3.b) **before** any pump protection logic was restored. The trip logic was restored by either removing the jumper in panel 1H13-P613, which would trip the pumps on a closure of the valve, or by reinstalling fuse G33A-F4, which would trip the operating pumps on low suction flow/pressure. In this event, valve 1G33-F004 began to close when the bus was re-energized (a possibility discussed in the procedure), but no automatic protective features were yet restored to trip the pumps prior to them possibly sustaining damage due to low/no flow conditions. The end result was the failure of the "C" pump.

A contributing factor to this pump failure may have been improper assembly of the pump during a previous overhaul. While reworking the pump, mechanics recognized that set screws which anchor an internal pumping ring were missing (reference Condition Reports 1-96-10-036 and 1-96-11-071). This discrepancy may have contributed to the "C" pump failure when suction flow was eliminated while the second operating pump, the "A" pump, did not fail.

c. <u>Conclusions</u>

Title 10 of the Code of Federal Regulations, Part 50, Appendix B, Criterion V, requires that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances. However, procedure CPS No. 3509.01C001, **Division I NSPS Bus Outage Checklist** was inappropriate in that operability of valve 1G33-F004 was restored prior to the restoration of any pump protection logic. This is considered a violation of NRC requirements (50-461/96009-01).

O1.4 <u>Unexpected Partial Loss of Control Room Annunciators</u>

a. <u>Inspection Scope (93702/71707)</u>

On November 4, the licensee experienced an unexpected partial loss of control room annunciators. The inspectors observed and reviewed compensatory and corrective actions taken in response to the event, a followup critique of the event, and the use of the following procedures:

- CPS 4201.01, "Loss of DC Power"
- EC-02, "Emergency Classifications"
- CPS 4201.01C006, "Loss of 125 VDC MCC 1F (1DC17E) Load Impact List"

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

At 6:42 a.m., the loss of DC power annunciator horn sounded in the main control room and the operators immediately determined that a loss of the P630 control room panel annunciators had occurred. The line assistant shift supervisor (LASS) directed reactor operators to continuously monitor vital systems, contacted the fuel floor to stop any fuel handling in progress, and declared the SRMs inoperable due to the loss of their alarm capability. The control room operators implemented CPS 4201.01 and attempted to silence the loss of DC power horn but were unsuccessful. The procedure revision summary section indicated that a procedure step to silence the horn by pulling its associated fuse was deleted because the horn was wired through the alarm silence buttons. This was incorrect and plant personnel had to investigate and identify the correct method for silencing the alarm.

The horn was very loud and was a distraction to the operators after the loss of annunciator condition was identified.

Additional compensatory actions were identified and implemented by the LASS and the shift supervisor, including dispatching other operators to tour and monitor other vital areas of the plant to identify any off normal conditions and ensure safe shutdown operations continued. The shift supervisor reviewed EC-02 to evaluate making an emergency-plan entry and determined that an entry was not required because appropriate compensatory actions were implemented.

The event was caused when a 30 A power supply fuse for the annunciator system failed. A plan was developed to replace the blown fuse and CPS 3503.01C003 was implemented to restore the annunciators to service.

During a review of the event, the licensee identified an open maintenance work request (MWR) to repair a hot spot that had been identified by thermography in June 1996. The MWR was scheduled for completion on January 15, 1997. Following identification of this open MWR, the work was rescheduled and performed during the refueling outage.

c. Conclusions

Operations personnel performed well during this event and the decision regarding the emergency classification was appropriate with the compensatory actions that were implemented. However, the inspectors noted that neither CPS 4201.01 or CPS 3503.01C003 identified any recommendations for compensatory actions for the loss of annunciators. Also, CPS 4201.01 had been incorrectly revised to delete the procedure step to silence the loss of DC power alarm by pulling its power supply fuse.

The inspectors also considered that although the identification of the hot spot via thermography was a very good observation, corrective action was inappropriately scheduled after the refueling outage during power operations.

O1.5 Alert Declared due to Fire

a. Inspection Scope (71707/93702)

The inspector responded to the site to observe the fire scene, review the circumstances surrounding the event, and review the Emergency Classifications Guide used to determine the appropriateness of the Alert classification.

b. Observations and Findings

On August 17, 1996, a RCIC system outage was entered to overhaul the turbine for an outboard gland seal steam leak. RCIC was declared operable on August 19, at 2:05 p.m. At 5:20 p.m. an operator on routine rounds noted smoke or steam rising from the turbine lagging. The operator contacted the control room and a second operator was dispatched to the area.

With the second operator standing by with a fire extinguisher, the first operator started removing the lagging. As oxygen reached the freshly exposed surfaces, a localized fire resulted which was extinguished within 15 seconds.

The operators notified the main control room and the plant fire alarm was sounded. The fire brigade assembled, responded, and a reflash watch was posted. The remaining lagging on the turbine was removed without incident. RCIC was declared inoperable due to potential temperature concerns in the room should RCIC be run without lagging.

An Alert was declared in accordance with Emergency Plan Implementing Procedure EC-01 due to a fire potentially affecting safety-related equipment. The Alert status was immediately exited due to the short duration of the fire; only the lagging was damaged as a result of the fire.

The fire was caused be overheating oil which had soaked into the lagging. The licensee ran the RCIC system to determine if the oil was from a past problem or from a current oil leak. The inspector observed maintenance workers wiping the entire turbine with dry white cloths while RCIC was running in an effort to identify any oil leaks. A minor weep was noted from the outboard bearing cap. The leak was so slight that it could not be determined if the leak was related to the fire. The cap bolts were tightened and the leak stopped. New temporary lagging was installed on the turbine and RCIC was declared operable by 11:18 p.m.

c. Conclusions

Following the identification of smoke, operations handled the situation in a controlled and effective manner. The declaration of the Alert was appropriate in accordance with procedures. However, oil soaked lagging fires have resulted in the licensee declaring one other Alert and one Unusual Event during the past two years. The inspectors consider this trend should be reviewed by the licensee through their trending program.

O1.6 Failure to Maintain Suppression Pool Temperature Log

a. Inspection Scope (71707)

The inspector reviewed the licensee's requirements to maintain a suppression pool temperature log to meet the technical specification (TS) surveillance requirements of TS 3.6.2.1.1, "Suppression Pool Average Temperature."

b. Observations and Findings

While reviewing control room logs, the inspectors noted the post-maintenance testing (PMT) of the reactor core isolation cooling (RCIC) pump following the completion of on-line maintenance on July 11, 1996. As part of their review, the inspectors asked to review the **Suppression Pool Temperature Log**, in order to determine the temperature increase seen in the suppression pool during the RCIC PMT. The inspectors were informed that no log had been maintained during this period.

The inspector reviewed the requirements of CPS 9000.05, "Suppression Pool Temperature Log," to determine if a log should have been maintained while RCIC was being run for PMT. This procedure required that a record of suppression pool temperature be maintained when the reactor is in Modes 1, 2, and 3 during any of three different events that could cause the suppression pool temperature to exceed 95°F. One of these events is any testing which adds heat to the suppression pool; PMT of RCIC was an example of such testing. Additionally, this procedure in conjunction with CPS 9000.01D001, Control Room Surveillance Log - Mode 1, 2, and 3," fully satisfied the requirements of TS 3.6.2.1.1.

In follow-on discussion with the operators, the inspectors determined that although the requirement to maintain the log was recognized a decision was reached to not maintain the log. In this instance, the operators determined that little, if any, heat would be added to the suppression pool due to the short duration of the RCIC PMT run. Additionally, prior to performing the PMT, operators had started the "B" train of residual heat removal in the suppression pool cooling mode to reduce suppression pool temperatures during the performance of the PMT.

The inspectors considered the requirements of CPS 9000.05 to be explicit and not subject to interpretation with regard to the potential for adding heat to the suppression pool. The failure to maintain a **Suppression Pool Temperature Log** is a violation of the requirements of TS 3.6.2.1.1 (50-461/96009-02).

c. Conclusion

One violation was identified for the failure to maintain a **Suppression Pool Temperature Log** as required to meet the surveillance requirements of TS 3.6.2.1.1.

O1.7 Operations Performance During Surveillances

a. Inspection Scope (71707, 61726)

The inspector observed multiple control room and one field performance of the emergency diesel generator overspeed trip test surveillance. Completion of one 24 hour diesel run and hot restart was also witnessed. Documents reviewed during the assessment included:

- CPS 3506.01: "Diesel Generator and Support Systems," Rev. 20
- CPS 3882.01: "Diesel Generator Overspeed Trip Test," Rev. 4 and Rev. 5

- CPS 1061.01: "Condition Reports," Rev. 27
- USAR Section 9.5.6: "Diesel Generator Starting Systems"

b. Observations and Findings

The control room operators generally implemented the procedure correctly during the observed diesel generator overspeed trip tests, 24 hour run, and hot restart, to ensure that the necessary readings were obtained and documented.

Communications between operators were usually formal with lapses being immediately corrected. Short term reliefs between control room operators were normally well executed. Clarity and thoroughness of short term reliefs were good on the initial relief but needed additional attention when the original operator returned to resume shift duties. For example, on one occasion the on-shift operator was relieved for a short break and when he returned the turnover provided by his relief was inadequate in that it did not discuss changes that had been done during his absence. Specifically, temporary lifting of control switch tags that had occurred were not relayed.

The inspector reviewed the completed CPS 3882.01 procedures and identified several questions related to the observed diesel generator overspeed trip tests. Specifically, the local operator's ability to obtain repeatable results, the reason for the trip setpoint's narrow acceptance band, and methods for obtaining local diesel rpm readings were questioned. These questions were discussed with the system engineer (SE) and resulted in Condition Report (CR) #1-96-11-251, "Div. 1 DG overspeed trip not performed per procedure," being written. A resultant procedure violation from this test was discussed in Section M1.2.

A fact finding critique was held to determine what changes, if any, were needed to procedure CPS 3882.01. After extensive research by the SE, an Engineering Change Notice was issued to change the overspeed trip setpoints for all three diesels in order to increase the operators' ability to obtain repeatable test results. Additionally, parts were ordered to install diesel generator local instrumentation to obtain rpm readings.

c. Conclusions

The control room operator demonstrated good communication, and referred to the procedure frequently. Short term reliefs of control room operators were adequate.

O3 Operations Procedures and Documentation

O3.1 Temporary Procedure Deviation (TPD) Usage

a. Inspection Scope (71707)

The inspector assessed controls used to modify CPS 3882.01, "Diesel Generator Overspeed Test," Rev. 4. Documents reviewed during the assessment included:

- CPS 1005.01: "CPS Procedures and Documents," Rev. 36

- CPS 1005.07: "Temporary Changes to Station Procedures and Documents," Rev. 20
- CPS 1401.01: "Conduct of Operation," Rev. 24

b. Observations and Findings

The inspector's review of CPS 3882.01 identified that it was extensively modified using the Temporary Procedure Deviation/Procedure Deviation for Revision (TPD/PDR) process. CPS 1401.01, "Conduct of Operation", Section 8.4.1.3, stated that "In other than emergency situations, when a procedural step cannot be completed as stated, the procedure shall be changed per CPS 1005.07, Temporary changes to Station Procedures and Documents, prior to work continuing." CPS 1005.07 provided confusing guidance by not clearly defining "Work In Progress". Interviews with operators, procedure writers, and managers confirmed that the definition of "Work In Progress", outlined in Section 2.2.4 of CPS 1005.07, was subjective and interpreted differently between individual workers and managers.

Individual workers and managers defined "Work in Progress" as anytime the activities outlined by a procedure were being performed or when the procedure was under review prior to actual performance. To further clarify the response, the inspector asked how early a procedure could be considered "under review" and still use the TPD/PDR process for changes. It was the consensus of those interviewed that there was no defined time limit and it was up to the individual to determine what type of process was used to modify or revise a procedure. Those interviewed seemed unaware of the Procedure Advance Change (PAC) process outlined in CPS 1005.01 This process was intended to be used when a procedure change was needed and time existed to allow the change to be done prior to actual performance of the procedure. In the case of the modification made to CPS 3882.01 several days were available to complete the revision prior to its scheduled use.

The inspector questioned plant management whether the modifications made to CPS 3882.01 met their expectation for implementation of the TPD/PDR process. It was stated that although the modification made to the procedure clearly enhanced its usability and clarified previous PDRs written against it, the extensive modification went beyond management's expectations for implementation of the TPD/PDR process.

c. Conclusion

Adequate procedures to implement and control procedure modifications, revisions, and temporary changes existed. However, a lack of clarity, mixed understanding of the intent, and implementation of the TPD/PDR process outside of management's expectations were considered weaknesses.

04 Operator Knowledge and Performance

04.1 Routine Operations

a. Inspection Scope (71707)

The inspectors observed routine control room and field activities and reviewed the following documents:

- CPS No. 3800.02, "Area Operator Logs"
- CPS No. 3800.02C001(2,3), C(D,E), "Area Daily Rounds Sheet for November 9-13"
- CPS No. 1016.01, "CPS Condition Reports"
- CPS No. 1401.01, "Conduct of Operations"
- Main Control Room (MCR) Journal
- Shift Supervisor (SS) Journal

b. Observations and Findings

The required rounds sheets were filled out correctly.

The inspector noted that some annunciator tests had been waived by the main control room staff to reduce the distractions in the control room. The inspector discussed this observation with the Assistant Director of Plant Operations, who then issued night orders to assure annunciator tests would be done. The inspectors asked if not performing the tests impacted any plant commitments. The licensee completed its investigation and identified that no commitments required these checks. During review of this question, the inspectors noted that Procedure 3800.02 cited Section 5.2.5.2.2 of the USAR when it should have cited Section 5.2.5.2.3. This was identified to the licensee. The licensee's review did not identify the error because its review was limited in scope to ensuring that the USAR sections cited in Procedure 3800.02 did not contain commitments. The licensee did not ensure that the listed sections were correct, nor did it perform a search of other sections of the USAR.

While the operators in the control room were generally alert to plant conditions, two exceptions were noted. The inspector observed dual indication on a condensate booster pump oil pump and questioned the operators about the indication. The operators stated that some control panel components had known dual indication problems and that a maintenance request had probably been written. The inspector determined that one had not been written; the operator then wrote one. During a different shift, an operator identified that there was no indication for a recirculation pump breaker. After further review, it was discovered that the breaker was removed for maintenance about one week before the operator had identified the indication problem.

Both instances of operators not noticing unusual indications on the control room panels indicated some weakness in attention to detail. It was recognized that an operator's questioning attitude led to identification of the recirculation breaker position. However, since this condition existed for more than one shift, the questioning attitude of other operations personnel was suspect. Prior to the conclusion of the inspection period, the licensee implemented a policy of performing and documenting main control room panel walkdowns every 2 hours.

Management expectations for MCR and SS journal entries were not of sufficient detail to cause journal entries to be clearly written so that a future reader would be able to understand the described event.

The inspector identified the following regarding SS and MCR journals:

- The SS and MCR journals' level of detail was sparse throughout the inspection period. The detail provided in the MCR journals was insufficient to confirm the why and when of some plant activities. For example, several log entries regarding starting or stopping equipment provided no reason for the change in status.

- Review of the SS journal identified that significant plant activities which occurred in a given week were not captured and summarized in the journal's weekly summary page. One example of this was the failure to document that an inspection had identified three foreign material items in the vessel. This information was not documented in the SS weekly summary entry.

c. Conclusion

Required operator rounds were performed correctly and control room operators maintained their awareness of plant conditions. However, the failure to review commitments prior to implementation, and the missed identification of unexpected equipment conditions demonstrated a lack of attention to detail.

Managements' expectations for control room journal entries were not clearly defined and resulted in entries that contained insufficient detail.

05 Operator Training and Qualification

O5.1 Conformance with Operator License Conditions, Maintaining Active Status

a. Inspection Scope (71001)

The inspectors reviewed the licensee's proficiency watch tracking for maintaining active operator licenses and assessed the licensee's compliance with 10 CFR 55.53 requirements. The licensee's program for performing medical examinations required by 10 CFR 55.21 was also reviewed.

Procedures reviewed included:

- CPS No. 1001.05, "Authorities and Responsibilities of Reactor Operators for Safe Operation and Shutdown"
- CPS No. 1401.01, "Conduct of Operations"

b. Observations and Findings

The inspectors identified that the licensee allowed licensed senior reactor operators (SRO) to take credit for active license duty proficiency watch standing in the Staff Assistant Shift Supervisor (SASS) position. This position was not a required licensed shift crew position defined in the facility's TSs. Subsequently, the operators were designated as Line Assistant Shift Supervisors (LASS), responsible for directing licensed activities, without completing 40 hours of shift functions in the LASS position under the direction of a senior operator.
No procedural direction existed concerning which shift positions should receive active license credit. However, operations management indicated that the practice of crediting the SASS with watch standing had existed since 1987. The inspectors questioned the licensee regarding whether active licensed duty credit for watch standing in administrative support positions was still being practiced. Operations management indicated that in September 1996, the SASS position was changed to Shift Resource Manager (SRM) and that the position would no longer receive credit toward license activation. However, on October 25th, during discussions with two SROs, the inspector identified that the SROs understood the SRM position could be used for credit toward license activation.

In addition to the lack of procedural direction discussed above, the system used to track licensed duty watch standing had no procedural guidance or controls. This contributed to the October 11, 1996, Active License Status Letter (RBB-96-002) being issued without the supporting proficiency watch documentation being complete for many licensed operators. One SRO identified in the letter as having an active license had his license status change to expired effective September 13, 1996, due to resigning his position.

The medical records of several licensed operators were reviewed with no concerns identified. The program for completing these requirements was conservative in that examinations were scheduled every 22 months. The medical records were organized with all required information included in the files.

c. Conclusions

The inspectors concluded that the licensee's practice for crediting watch standing time for senior operators in positions that did not require the individual to be licensed as defined in the facility's TSs was inappropriate. Subsequently designating these individuals as the on-shift LASS without prior completion of 40 hours in the LASS position under the direction of a senior operator was contrary to NRC requirements and a violation of 10 CFR 50.54(l), " Conditions of License," 55.53, "Conditions of Licenses," and 55.4, "Definitions" (50-461/96009-03(DRP)).

The lack of procedural controls related to maintaining active operator's licenses was also a weakness.

07 Quality Assurance in Operations

O7.1 Fact Finding Investigations

a. Inspection Scope (71707)

During the inspection period, the licensee performed several fact finding critiques of problems encountered during work activities. The inspectors observed portions of these critiques and compared the results to observations made during inspections of the work activities. Critiques observed included:

- Manual isolation of shutdown cooling system due to process radiation monitor indications
- Unexpected auto start of EDG during overspeed testing
- Work in the under vessel area with the traversing incore probe system not in the correct storage location
- emergency diesel generator overspeed trip test critique for CR #1-96-11-251

b. Observations and Findings

The licensee maintained an open atmosphere. The fact findings were done in a non-judgmental manner. This was conducive to getting all the information and establishing the correct sequence of events. The information gathered agreed with what the inspectors had learned or observed of the events.

c. Conclusions

The observed fact finding investigations were effective in obtaining information. They were conducted in an open and non-judgmental manner and concentrated on identifying issues that plant management could use to develop corrective actions.

08 Miscellaneous Operations Issues

O8.1 Safety Tagging

a. Inspection Scope (71707)

The inspectors noted an increase in tagging-related condition reports (CRs). Methods and procedures used for tagging equipment out of service, and returning equipment to service were reviewed, and existing tagouts were verified. Procedures reviewed included:

- CPS No. 1014.01, "Safety Tagging"

- Condition Reports created during the past year associated with safety tagging
- Critique OP-96-007, Critique for TIP detectors in incorrect location for authorized work, dated October 24, 1996
- OPS-96-003, Self-Assessment Report Regarding the Adverse Trend with the Safety Tagging Program, dated January 12, 1996.
- Common Cause Analysis associated with Condition Report 1-96-10-371-0, Safety Tagging Adverse Trend, dated November 6, 1996.
- Tagout Sheets for Tagout Numbers 96-9339 (SX), 96-9063 (MS), 96-9002 (RP).

b. Observations and Findings

Review of safety-tagging related condition reports revealed examples of unanticipated impacts from tagouts, electrical tagouts being temporarily lifted while workers were near the energized equipment, tagouts inadequate to support work, and a Nuclear Assessment Department (NAD) finding that some long-hanging tagouts were not given required safety evaluations. The number of errors increased as outage work commenced.

Independent of NRC review, the licensee also identified an adverse trend. Historically, the licensee last identified an adverse trend in tagging in January 1996 when 8 CRs were written. Errors dropped to about two per month from March to July, but then increased to 28 during October. Common-cause analysis indicated that most errors were in judgement and attention-to-detail. Immediate corrective action taken by the licensee included re-verification of hanging and issued tags, and reviews of tagouts greater than six months old. The root cause and long-term corrective action report was to be completed at the end of November.

The inspector noted that some of the corrective actions for previous tagging events was slow. Specifically, a tagout hung on July 25, 1996, inadvertently tagged out security lighting. The licensee corrective action included hanging a caution tag on the circuit with a due date of October 14, 1996. On September 6, and again on September 29, 1996, similar events occurred. Title 10 of the Code of Federal Regulations, Part 50, Appendix B, Criterion XVI, requires that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. The repetitive inadvertent isolation of security lighting power is considered a violation of NRC requirements (50-461/96009-04).

The safety tagging procedure, CPS 1014.01, required that the personnel hanging tags verify that the tag, tagout sheet, component equipment identification number (EIN) and position all match. This requirement has not been treated as a verbatim match, but instead to assure the correct tag was hung on the correct equipment in the correct configuration. Inspector observation of tagouts in the field showed that the text names and equipment identification numbers on the tagging sheets did not always match. For example, in tagout 96-9063, the EIN for tag #1 was listed as "1B21-F047B" whereas the control switch was labeled as "1B21C F047B." There were also differences in how components were abbreviated on various tagouts which again resulted in non-verbatim matches to the nameplates. In tagout 96-9010, the inspector noted that the tagout referred to "RHR A Shutdown Cooling Suction Valve" and "RHR A Shutdown Cooling Return Valve," whereas the nameplate on the breakers was "RHR A Shutdown Cooling Injection Valve." for both valves. The licensee initiated CR 1-96-11-025 to document and correct the latter.

The inspector also noted that some tag positions had to be modified by the tag hanger to reflect the actual indications on the control switches. For example, in the tagout 96-9063 the position of tags 33 to 38 were field-changed from "Normal" to "Close" to match the actual switch positions.

The information on the tagouts came from a computer database and from prints available to the personnel who wrote the tagouts. The inspector determined that no formal feedback mechanism existed to correct the computer database used in creation of tagouts. The operators would therefore probably have to correct these tags again in the future. Although, no incorrect isolations were identified which resulted from non-matching tags or changes to position descriptions, the failure to ensure the documentation used to generate tagouts accurately reflects nameplate data in the field is considered a weakness.

c. Conclusions

The licensee correctly identified an adverse trend with safety-tagging. However, the root causes evaluation and the development of long term corrective actions had not been completed at the conclusion of the inspection. The licensee was also considering instituting a feedback mechanism to correct inconsistencies between component EIN, equipment tag name, and tagout sheet component identifier. Additional inspector identified errors involving non-verbatim matches between components and tags did not result in any incorrect isolation boundaries. A violation was identified for inadequate corrective actions for safety-tagging errors.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726)

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

- CPS 9052.01, "Low Pressure Core Spray (LPCS) Pump Operability"
- CPS 9052.02, "LPCS Valve Operability"
- CPS 9053.04, "RHR 'A' Valve Operability"
- CPS 9053.07, "RHR 'A' Pump Operability"
- CPS 9080.21, "Emergency Diesel Generator (EDG) 1A ECCS Integrated"
- CPS 9080.22, "EDG 1B ECCS Integrated"

- CPS 9861.02, "Local Leak Rate Test for Containment Penetration 1MC010"
- CPS 9015.06, "Cold Shutdown Standby Liquid Control Pump and Valve Operability Check"
- CPS 3560.01, "Diesel Generator and Support System"
- CPS 3882.01, "Diesel Generator Overspeed Trip Test"
- CPS 8121.02, "Control Rod Drive Overhaul"

b. Observations and Findings

Most of the surveillances were completed without incident. See the sections below for discussions on specific surveillances.

M1.2 Performance of Emergency Diesel Generator Overspeed and Integrated Testing

a. Inspection Scope (61726)

The inspectors observed control room and field performance of surveillances on the emergency diesel generator (EDG) systems.

b. Observations and Findings

The inspectors observed the EDG overspeed trip test for tandem engines performed on November 3, 1996, per CPS 3882.01. Some weaknesses were identified.

- Step 8.3.a required a portion of the EDG shaft safety guards be removed to allow safe access to the shaft for monitoring engine speed using a handheld tachometer. A portable tachometer was required as the range of the installed instrumentation was not adequate to ensure engine speed remained below 1045 rpm. This step was "Noted Out" and not performed with the reason given that "the new Strobotach does not need cover removal." The "note out" resulted in the operator having to remove the flywheel cover and put his arm in past the flywheel to read the tachometer. The decision not to remove the shaft safety guard increased the potential for injury to the operator. It also contributed to the failure of the operator to obtain the required response from the tachometer during the test and inform the operator controlling the engine speed prior to the engine tripping on overspeed.

- Step 8.3.i required the engine speed be increased slowly by "very slowly **pushing** the lay shaft lever towards the centerline." The procedure then directed engine speed to be increased until the engine tripped, not to exceed 1045 rpm. A CAUTION statement just prior to step i warns the operator "Do not exceed engine speed of 1045 rpm." Contrary to the procedure steps, the operator **pulled** the lay shaft lever decreasing the engine speed to about 620 rpm. He realized the engine speed was decreasing and pushed the lever towards the centerline to increase speed. A second operator was attempting to monitor engine speed with the Strobotach but was not able to get the meter to respond during the increase in engine speed. The operator working the Strobotach attempted to inform the operator at the lay shaft lever that the tachometer was not functioning when the engine tripped on overspeed. Later analysis of plant computer information indicated that the DG tripped at about 1025 rpm and did not exceed the 1045 rpm limit.

Title 10 of the Code of Federal Regulations, Part 50, Appendix B, Criterion V, requires that activities affecting quality shall be accomplished in accordance with instructions, procedures, or drawings. Failure to follow the instructions of CPS 3882.01 as discussed above is considered a violation of NRC requirements (50-461/96009-05).

On October 15, during performance of CSP 9080.22, Diesel Generator IB ECCS Integrated, Section 8.5.19.4, the reserve auxiliary transformer (RAT) tripped during an attempt to parallel the 1B EDG to the electrical grid due to a reverse power condition. A second attempt to parallel was performed with the same results. An investigation into this event determined that the synch check relay closed indication as compared to the indication in the control room differed by 5° which caused the indication problems in the control room. The breaker closed on the third attempt with the synchroscope reading about 12:05 at closure. Operators stated that problems with the synch check relay had been identified in the past with several attempts being made to close the breakers. They also indicated that reverse power trips of the engines had often occurred once the breakers were closed. EDG synchronization relay check problems is considered an Inspection Followup Item (50-461/96009-06).

c. Conclusions

Several problems were encountered during execution of the diesel engine tests. A violation was identified where operators failed to follow procedural instructions and performed steps incorrectly.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Untimely Completion of Use History Analyses (UHAs)

a. Inspection Scope (62703)

The inspectors reviewed the licensee's process for evaluating the effects of out-of-calibration test equipment on previously calibrated plant equipment.

b. Observations and Findings

On October 25, 1996, CR 1-96-10-358 was written to document the failure of a surveillance due to test equipment being out of calibration. The surveillance, which was performed on the leakage control system for the main steam isolation valves (MSIVs), was completed on November 9, 1995. In January 1996, calibration laboratory technicians identified that the as-found data for the test equipment used to perform the surveillance did not meet the required acceptance criteria. When this condition occurs, procedures require that a UHA be completed to determine the specific equipment that may have been effected by the out-of-calibration test equipment.

CPS 1512.01, "Calibration and Control of Measuring and Test Equipment," Step 8.10.2.6, states that UHA forms shall be completed and returned to the Supervisor-C&I, within 21 days from the date the use analysis was initiated (the day the test equipment was found out-of-calibration). In this instance, the UHA was not completed until 10 months later.

The inspectors questioned the lack of timeliness for completing UHAs. A review of the UHA log determined that 57 UHAs, dating back to January 1996, had not been completed within the time required by procedure. The Supervisor-C&I told the inspector that he wanted the overdue UHAs completed within two weeks in order to identify any equipment which needed to be re-calibrated. At the conclusion of the inspection, approximately 15 UHAs were yet to be done. Of those that were completed, only the UHA documented in the CR above needed an additional operability evaluation.

The inspectors reviewed the operability evaluation for the MSIV leakage control system and found one weakness. This weakness is discussed in section E1.1. No other problems were identified.

A review of the CR database determined that the lack of timeliness in completing UHAs was previously identified during a nuclear assessment department (NAD) audit in June 1995. NAD surveillance report Q-17130 stated that of the 119 UHAs reviewed, thirty percent were not completed within the time required by procedure (CR 1-95-07-007 was written to document this). The C&I department began to publish a periodic status of UHAs as part of the corrective actions for CR 1-95-07-007. However, the Supervisor-C&I told the inspector that the periodic status of UHAs was no longer published.

In response to a CR written in 1994 pertaining to inadequate UHAs, the C&I department committed to performing a quarterly audit of UHAs. An audit completed August 8, 1996, stated that there were a large number of UHAs that had not been completed within the required 21 days. Results of the audit completed October 25, 1996, were unsatisfactory in that 66 UHAs dating back to January 4, 1996, were past due. No action was taken in response to the August audit. Subsequently, a condition report pertaining to untimely UHAs was initiated approximately one week after the October audit was completed.

c. <u>Conclusions</u>

Although no rework has been required, the current status of the UHA program was poor. In addition, this issue was significant because the C&I department was not meeting procedural requirements and failed to perform corrective actions which were put in place to prevent additional timeliness problems. Title 10 of the Code of

Federal Regulations, Part 50, Appendix B, Criterion XVI requires that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. The licensee's failure to identify and correct this problem in a timely manner is a violation of NRC requirements (50-461/96009-07).

M3 Maintenance Procedures and Documentation

M3.1 125 VDC Battery Service Test

a. Inspection Scope (61726)

The inspectors reviewed the following Division I 125 V Battery surveillances:

- CPS 9382.12, "Div I 125 VDC Battery Service Test," completed November 3, 1996
- CPS 9382.12, "Div I 125 VDC Battery Service Test," completed April 7, 1995
- CPS 9382.13, "Div II 125 VDC Battery Service Test," completed November 13, 1993
- CPS 9382.12, "Div I 125 VDC Battery Service Test," completed April 28, 1992

b. Observations and Findings

In general, the tests appeared to be executed correctly. Some equipment problems occurred during the tests, but the licensee took appropriate action.

The inspectors identified two minor problems in the data analysis for the test performed in April 1995, and one minor problem with the procedural guidance common to all the tests. The two analysis errors were an omission of a level correction factor and an error in averaging numbers. These were considered isolated examples of personnel error. The procedural problem resulted in double-counting the pilot cell under certain circumstances during the temperature averaging steps, thereby resulting in a statistically incorrect average. The inspectors also noted inconsistent use of significant figures between tests. The errors identified did not cause the battery to be inoperable or outside of its acceptance criteria.

The inspectors discussed the errors with the current and former DC system engineers. They documented the errors in CR No. 1-96-11-226. The engineers indicated that they had identified the differences in use of significant digits, and that they were discussing what guidance to provide.

c. Conclusions

Incorrectly applying level corrections and mis-calculating averages was an attention to detail problem. However, these errors did not impact the operability of the battery.

III. Engineering

E1 Conduct of Engineering

E1.1 Evaluation of Operability Determination for MSIV Leakage Control System

a. Inspection Scope (37551)

The inspectors reviewed the results of operability determinations to support the resolution of CRs 1-96-10-282 and 1-96-10-358.

b. Observations and Findings

During a review of the operability determination for the channel 1E32N056 of MSIV leakage control, it was noted that the acceptance criteria given in the surveillance procedure (as stated in the operability determination) was not consistent with the information taken from the design specification data sheet. The inspectors questioned this inconsistency and were told that the information taken from the design specification data sheet was transposed incorrectly. The transposition error had no effect on the results of the operability determination and the correct information was provided in a revised document. However, the inspectors were concerned that this error was not questioned during the review performed by the plant engineering group leader and was subsequently used to justify system operability.

c. Conclusions

Overall, the methodology used to perform both operability determinations considered the necessary information. However, the missed opportunity to identify that the setpoints used to prove operability for 1E32N056 were incorrect demonstrated a lack of rigor in the performance of operability determinations.

E1.2 Resolution of Reactor Core Isolation Cooling (RCIC) System Problems

a. Inspection Scope (37551)

The inspectors reviewed engineering actions associated with the resolution of water in the RCIC turbine lube oil. In addition to reviewing the justification for continued operation of the RCIC system, the inspectors evaluated the aggressiveness of troubleshooting activities and engineering's support to the operations department.

b. Observations and Findings

Background

On July 11, 1996, following a 6 hour RCIC system surveillance test, a RCIC turbine lube oil sample indicated 50 percent water by volume. An additional cold sample on July 17 contained approximately 2 ounces of water in a 16 ounce sample.

The licensee drained and cleaned the oil sump, and refilled it with water free oil. Following a short RCIC system run, an oil sample again revealed water in the oil. Additional samples taken from July 23-29 exhibited decreasing amounts of water with the last sample showing no visible evidence of water.

Evaluation of Initial Operability Determination

Following the July 11 discovery of water in the RCIC system lube oil, engineering personnel assured the Operations Department that the system was operable. However, when questioned by the inspectors about how much water was acceptable, the engineering staff did not have the information and the vendor manual (K2801-0030) made no reference to water in the oil. At this point the licensee initiated Condition Report (CR) 1-96-09-183.

Two and a half weeks after the initial discovery the inspectors asked a plant engineer familiar with oil analysis what the acceptance criteria was for water in the RCIC turbine lube oil. This engineer stated that 0.5 percent water by volume, based on the entire oil volume, was acceptable. The inspector asked what the concentration of oil on July 11 was; the engineer calculated approximately 0.9 percent. Apparently this calculation had not been performed prior to this time.

Once it was recognized that the oil sample exceeded the 0.5 percent acceptance criteria, engineering contacted the turbine vendor for additional clarification. These discussions resulted in the acceptance criteria being changed such that 0.5 percent water was an action limit, 1 percent water required immediate action, and 2 percent water required shutdown of the turbine as soon as possible. Based on the information known by the licensee both before and after the acceptance criteria were revised, immediate action should have been taken per the vendor's instructions.

Review of Technical Basis for Operability

While the RCIC system is not required to operate during an accident condition, the licensee's probabilistic risk assessment model assumed that RCIC would operate for 24 hours during a high pressure transient event where high pressure core spray and feedwater systems were unavailable. Because of its importance, the licensee developed a technical basis for operability and a calculation for how much water could accumulate before entering the oil pump suction.

The inspector identified a number of concerns with both documents. The licensee had assumed a constant water intrusion rate that testing did not support. Further, the licensee's calculations did not consider dynamic affects on water transport, did not support their contention that water would rapidly precipitate out, and used the wrong size line in determining the volume to be filled with water prior to water being drawn into the oil pump suction.

The licensee's evaluation of these concerns determined that the operability determination was not impacted by these weaknesses; however, the issues raised identified a lack of rigor in the technical basis of the review.

Troubleshooting Actions

The licensee initially suspected the water was entering the turbine lube oil system through a leak in the oil cooler. During subsequent testing the licensee determined that a steam leak on the outboard turbine gland was the major source of water entering the oil system. A system outage was accomplished during the week of August 17 to repair the steam leak. With the exception of the oil fire referenced in Section 01.5, the outage was successfully accomplished ahead of schedule.

c. Conclusions

Although the inspectors considered that RCIC remained operable the entire period, engineering response to the initial identification of water in the RCIC oil system was slow. The failure to determine an acceptance criteria for water in the lube oil for over a month, and failure to assess the condition of RCIC using that criteria, once established, demonstrated poor engineering rigor in the monitoring of TS related equipment. Once the steam leak was identified, the outage addressed the sources of water inleakage and was effective in resolving the problem. Performance by the maintenance department was excellent.

E2 Engineering Support of Facilities and Equipment

E2.1 Continued Local Leak Rate Testing Failures of Feed Water Check Valves

a. Inspection Scope (37551/62703)

The outboard feed water (FW) check valves (1B21-F032A & B) have failed every as found local leak rate test (LLRT), and the inboard FW check valves (1B21-F010A & B) have had many failures. The inspectors reviewed past corrective actions, test methodology, and current actions planned to resolve the problem.

b. Observations and Findings

Outboard Feed Water Check Valves

The outboard FW check valves are 20 inch, air assisted, non-slam type tilting disc check valves. They have failed to meet the as found 9 pounds per square inch air LLRT acceptance criteria for six consecutive refueling outages. During several refueling outages, the licensee has attempted to improve the valve's performance. However, these actions proven inadequate during each subsequent LLRT.

In RF-2, the licensee could not get either outboard check valve to pass the as left LLRT. An NRC inspection of the problem identified that the outboard FW valves had also failed the as left LLRT during RF-1 (Inspection Report 91002 section 5.c) and a violation was issued. The licensee requested and was granted a one time exemption to 10 CFR 50, Appendix J, and an exigent TS change, which allowed operating through cycle 3 with the condition. The exemption was to provide adequate time for evaluating solutions which would result in acceptable air leakages and ensure lasting performance of these valves.

In RF-3, the licensee rebuilt the valves to more precise tolerances and alignment criteria. This included installing new blank valve discs, machining valve disc and seat angles, and align-boring the valve hinge assemblies to provide a more precise fit (licensee event report (LER) 92003).

In RF-4, the licensee determined that the valve actuators were incapable of performing their design function of fully seating the valve disc. Instead the valve was acting like a simple check. The problem was due to a deficient manufacturer's design. In addition, the licensee did not recognize the problem during RF-3 due to a lack of understanding of the valve actuator's design function. Licensee personnel involved during the RF-3 repairs assumed that the actuator's function was only to assist valve closure rather than to provide a closing force to fully seat the valve disc as required by the design basis (LER 93005).

In RF-5, the as found failure of one outboard FW check valve (1B21-F032A) was due to an off center condition of the disc. The disc pivots on two hinge pins with a 0.010 to 0.025 inch axial clearance to allow for thermal expansion. However, the same clearance allows the potential for disc misalignment with the seat. Without the disc centered on the seat, the tapered disc makes contact with only a portion of the tapered seat. The lack of contact results in an unacceptable leakage rate. The licensee postulated that a hydraulic piston effect on the limit switch shaft may have shifted the disc position or low fluid flows through the valve associated with shutdown conditions did not allow the disc to close with sufficient force for the disc to self center. The cause for the unacceptable leakage rates through the 1B21-F032B valve could not be determined. The licensee modified both valves to eliminate the potential hydraulic piston effect by replacing the limit switch shaft with a simple hinge pin and hinge pin cover (LER 95002).

Following both as found LLRT failures of the outboard FW check valves in RF-5, the licensee decided to perform an informational test of the F032B valve. The actuator was disconnected and an attempt was made to manually swing open the valve and then let it close. The licensee staff were unable to move the actuator shaft. The valve bonnet was removed and the inside of the valve was found to be half full of water. The licensee did not recognize that the slope of the feed water piping caused the valve to be a low point which could not be drained with the existing drains. The piping slope that existed for both FW lines was in accordance with the design. However, the licensee missed this fact at the time and attributed the water to be the result of an inadequately performed drain lineup.

The licensee also modified the LLRT procedure to refill the FW line with water following valve work and then drain the line in a specific order. This was the first time the licensee did not go directly to an as left LLRT test following maintenance.

Their goal was to use the draining to aid in the seating of the valve by better simulating what would happen during an accident. Using this methodology, the valves appeared to pass their as left LLRT following RF-5.

Following the RF-6 as found LLRT failures, the licensee performed a satisfactory as found 1000 psig water LLRT on the inboard and outboard "A" check valves. An informational second air LLRT was then performed on the 1B21-F032A valve to see if the previous 1000 psig test and the water draining sequence would improve the valves performance. The valve still failed the LLRT. Upon opening the valve following this second test, the valve was found to be half full of water. Having water present instead of air did not meet the requirement of ANSI/ANS 56.8-1994 section 6.3 "System Line-up." Section 6.3 stated, "Systems that contain water during normal operation, but are not designed to be water filled following a design basis accident, shall be drained to expose the barrier under test to the test medium."

At the inspectors prompting, the licensee reviewed previous refueling outage LLRTs to determine if the possibility existed for water to remain in the valves during testing. The licensee determined that the as left testing of outboard feedwater check valves during RF-5 was also invalid since the same test methodology was utilized. A 10 50.72 notification was made with an LER to follow. The licensee has added a drain valve to the bottom of the outboard check valves and changed the test procedure to provide adequate draining before performing the air test of the valve.

To improve valve seating, the licensee added 48 pounds of counter weight to the valve disc to enhance the closing force of the disc. The valve failed the LLRT again and the licensee started a research and design effort on a similar valve in the maintenance shop. The goal was to determine the most effective modification for permanently improving the valves' performance.

Although the licensee made extensive changes to the outboard feedwater check valves during refueling outage 3, the valves have continued to fail every as found 9 psig air LLRT in each succeeding refueling outage. The failure of the licensee to invoke corrective actions to preclude repetitive as found LLRT failures is an apparent violation of 10 CFR 50, Appendix B, Criterion XVI (50-461/96009-08a).

<u>Inboard Feed Water Check Valves</u>

The inboard FW check valves are 18 inch, non-slam type tilting disc check valves. During the first 3 refueling outages, the inboard FW check valves had repeated as found failures. The valves were repaired and passed as left LLRTs before completion of each refueling outage. During RF-3, the valves were rebuilt to more precise tolerances and the soft seats were once again replaced. The elastomeric soft seats were qualified for an 18 month service life.

In RF-4, the valves passed the as found LLRT. Engineering evaluated the 18 month service life rating and authorized extending the service life for another cycle. In RF-

5, the valves failed the as found LLRT due to deterioration of the elastomeric soft seats. The soft seats were replaced with new soft seats rated for an 88 month service life.

In RF-6, the valves failed the as found LLRT due to failure of the soft seat. The condition of the 88 month service life soft seats was significantly worse than the 18 month soft seats after 36 months. The licensee forwarded the seats to an independent testing laboratory for failure analysis. The results of the analysis were not available at the conclusion of the inspection period.

The inspector observed maintenance activities for replacement of the soft seat on 1B21-F010B and modification work on the 1B21-F032B both in the field and the shop. The actual maintenance work was accomplished in accordance with procedures and in an effective manner. The problem with the outboard check valve appears not in the quality of the maintenance work but in the actual valve design used for this specific application.

c. Conclusions

During RF-6 both the inboard and outboard FW check valves failed their as found LLRT with the leakage beyond quantifiable levels. The inboard check valve soft seats were significantly more degraded than in previous refueling outages with the bottom section of the soft seats being worn below the seating surface of the disc. Therefore, the inboard check valves became incapable of performing their safety function sometime during fuel cycle 6. Based on the repeated as found failures of the outboard FW check valves coupled with the inadequate as left testing during RF-5, both outboard FW check valves were incapable of performing their safety function during all of fuel cycle 6.

Combining these facts, two containment penetrations were inoperable during fuel cycle 5 and would have provided two release paths to the environment under certain accident conditions.

Although the licensee had ample opportunity to identify the inadequate outboard FW check valve test methodology during RF-5, the problem was not identified until RF-6. The licensee in an attempt to prove the valves were properly functioning, modified the test method in RF-5 to maximize the chances of success. During the procedure change process they failed to ensure that the valve seat being tested was drained of water before the test proceeded. Technical specification 3.6.1.3.8 requires the licensee to verify the combined leakage rate for all secondary containment bypass leakage paths to be $\leq 0.08\ L_a$ (maximum allowable leakage rate for the primary containment) when pressurized to $\geq P_a$ (Maximum peak containment pressure). For the FW check valves, this was to be accomplished in accordance with Clinton Power Station Procedure (CPS No. 9861.02) Local Leak Rate Testing Requirements and Type C (AIR) Local Leak Rate Testing. CPS 9861.02 prerequisite 5.10.1 stated "Prior to leak testing containment isolation valves, both sides of the valve seat shall be drained below the valve seating surfaces for air tests." The failure of the licensee to ensure the procedure adequately drained the FW line to below the valve seating surfaces is an apparent violation of TS 3.6.1.3.8 (50-461/96009-08b).

E2.2 Troubleshooting Efforts on Fuel Building Crane

a. Inspection Scope (37551)

The inspectors reviewed the work performed to troubleshoot recent operational problems with the fuel building crane. The inspection included a review of troubleshooting results and discussions with engineering personnel. The maintenance history of the fuel building crane was also reviewed.

b. Observations and Findings

While lowering a fuel assembly into the new fuel vault on August 28, the fuel building crane stopped abruptly due to failure of one of the fuses for the fuel building crane auxiliary hoist brake rectifier. Engineering personnel responded to the site to provide further guidance on troubleshooting activities and provided continuous coverage until the issue was resolved.

In discussions with the crane operator, engineering personnel learned that the crane was being quickly jogged many times during the new fuel receipt process. Engineering determined that part of the crane circuitry consisted of a timer which allowed the current seen by the rectifier fuses to remain higher than normal for approximately 1 second in order to overcome starting current. However, due to the excessive jogging of the crane, engineering personnel hypothesized that the timer was continuously being reset which caused the duration of the increased amperage to exceed the fuse's capabilities.

The following day, engineering personnel contacted the crane vendor to discuss possible relationships between jogging the crane and fuse failure. The vendor concurred that subjecting the crane to excessive jogging may have resulted in the failure of the motor and brake rectifier fuses. Since engineering personnel believed that they had determined the root cause for the fuse failure, the fuses were replaced on August 29 and new fuel receipt processing continued.

During the afternoon shift on August 29, the ability to raise and lower the fuel building crane ceased due to additional problems. Again, engineering personnel responded to the site to assist electrical maintenance in the troubleshooting efforts. The next day, the vendor and engineering personnel determined that the "A" phase contact of the contactor for lowering the auxiliary hoist was exhibiting excessive arcing because of insufficient contact pressure. Due to the design of the circuit, the arcing "A" contact resulted in continuously re-setting the timer and therefore the 3.2 amp brake rectifier fuses were subjected to 8-10 amps for a time sufficient to cause failure of the fuses. The failure of the 3.2 amp fuses caused a locked rotor condition on the hoist motor which also caused the 100 amp main line fuses to fail.

To correct the condition described above, the main line fuses and the contact sets for both the raise and lower contactors were replaced. The receipt of new fuel then proceeded as scheduled. A visual inspection of the contacts used in lowering the auxiliary hoist determined that "A" phase contact spring had a smaller spring coefficient than those found on the "B" and "C" phase contacts. The vendor indicated that the springs were changed to a different style a few years ago. The inspectors reviewed the fuel building crane maintenance work history with a plant engineer and found that in 1995 the contacts for the lowering contactor were changed to the contacts with a new style of spring due to similar problems with the crane (the licensee was unaware that the style of springs had changed). However, since only two sets of contacts were available from stores, and the condition of the "A" contacts was not as degraded as the other two sets, only the "B" and "C" contacts were replaced. Although a work request should have been written to replace the "A" contacts, a request was not initiated until the current problems were discovered. As part of the condition report follow-up actions, the plant engineer reviewed parts lists from the other cranes to ensure that they did not use the same style of contacts as the fuel building crane.

c. Conclusions

The inspectors considered the failure to initiate a work request on the "A" phase contact a poor work practice. Engineering actions during troubleshooting activities were effective in determining the root cause of the crane problems. The inspectors considered the engineer's aggressiveness in evaluating the status of the other cranes to be a positive initiative.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Tour of the Turbine Building

a. Inspection Scope (71750)

On October 3, 1996, the inspector performed a tour of portions of the turbine building to observe radiological worker practices.

b. Observations and Findings

During the tour, the inspector observed facilities personnel transferring laundry from a contaminated laundry cart to a sea-land container located in the turbine building truck bay. The inspectors thought it was unusual that the facilities personnel were carrying the bagged laundry approximately 200 feet from the cart to the container since once the laundry bag was placed in the cart it was to be considered contaminated.

The inspectors also questioned the manner in which the laundry bags were placed inside the container. For example, an area inside the container had been roped off since the placement of other laundry bags had created a contaminated area. Although the bag was placed in the contamination area correctly, the facilities personnel ensured that the bag would not cross over the contaminated area boundary by forcing the bag further into the area using an unprotected foot (individual had shoes on but no rubber overshoe). When questioned by the inspector, the individual stated that she had not broken the plane of the contamination area with her foot. The inspector was unsure of how an individual could push a bag beyond the area boundary without breaking the plane.

CPS 1024.40, "Contamination Control," Step 8.4.1, states that protective clothing (i.e. coveralls, shoe covers, gloves, etc.) is required for entry into contamination areas. The failure to wear shoe covers when pushing the potentially contaminated laundry bag over the contamination boundary is a violation of TS 5.4.1.a., in that entering a contaminated area was not accomplished in accordance with written procedures (50-461/96009-09). This occurrence was discussed with the radiation protection (RP) supervisor. The RP supervisor indicated that the performance of the facilities personnel did not meet his expectations and that further discussions with the facilities supervisor would be held to prevent recurrence.

c. Conclusions

Although the worker's foot was not contaminated, the practice of crossing a contaminated area boundary without proper protection was considered a poor radiological worker practice and a violation of station procedures.

R3 RP&C Procedures and Documentation

R3.1 Area Radiation/Process Radiation (AR/PR) and Emergency Operating Procedure-8 Table U

a. Inspection Scope (71707, 40500)

The inspector reviewed the licensee's discovery that the emergency operating procedures (EOPs) contained inaccurate information regarding area radiation monitors. The inspector discussed the response to alarms with operations and RP staff and reviewed the following documents:

- CPS No. 1005.09, "Emergency Operating Procedure Program"
- CPS No. 1401.01, "Conduct of Operations"
- EOP-8, "Secondary Containment Control"
- CPS-USAR 12.3.4, "Area Radiation and Airborne Radioactivity Monitoring Instrumentation"
- Condition Report 1-96-11-256
- RPSO-022, Rev. 1
- CPS No. 7410.10, "Investigation of AR/PR Annunciator Alarms"
- CPS No. 7410.71, "Operation of the AR/PR CCT, and PCT"

- CPS No. 1902.22, "Radiation Protection ODCM Operation Requirement Report Tracking"
- CPS No. 9911.24, "AR/PR Shiftly/Daily Surveillances"

b. Observations and Findings

On November 16, an RP shift supervisor reviewed the status and requirements for area radiation monitors and determined that the AR/PR monitors listed on Table U, "Area Radiation Limits," of EOP-8 did not reflect actual plant conditions. The review was undertaken because of a concern regarding the length of time (since May 2, 1996) one of the detectors had been inoperable. The table contains detector locations, methods of survey, channel on the AR/PR system, and radiation levels.

Table U of EOP-8 is used to determine if entry into the EOP is required. A review of the table determined that the table incorrectly listed two addresses, implied incorrect detector locations, and listed one detector address for a detector which was removed. For example, the monitor in the hallway near RHR Equipment Room B had the wrong address listed in the EOP table and was labeled as "RHR Equip Room A" in the field. The inspector reviewed the Updated Safety Analysis Report (USAR) and noted it better described the actual locations. For example, the USAR listed the detector as "Auxiliary Bldg. West" rather than "RHR Equipment Room B," which clearly indicated that the detector was not in the RHR room.
The shift supervisor was notified of the EOP discrepancies via CR 1-96-11-256 on November 16. A mode restraint was created to ensure that the EOPs were updated prior to reactor restart.

On November 19, the inspectors determined that the operating crew, with the exception of the shift supervisor, was unaware of the CR regarding the EOP table. The inspectors reviewed CPS No. 1401.01, "Conduct of Operations," and determined that because of plant conditions, the crew was not required to be aware of the discrepancies. Nonetheless, the operating crew indicated that this information was important and should have been discussed during shift turnover. The inspectors noted that the information about the EOPs was turned over to the next shift.

CPS No. 1005.09, "Emergency Operating Procedure Program," Rev. 5, stated in part, "...it is imperative that the procedures in the [critical EOP locations] be maintained at the highest level of readiness, and that new revisions be updated in a timely fashion." Incorrect data on the EOP indicated that the procedures were not being maintained and updated properly.

In addition to the difference in the names of the AR/PR detectors in the USAR and the EOPs, one USAR error was noted: during verification of detector locations with the inspector, the RP shift supervisor noted that USAR detector location drawings showed the detectors on the wrong wall of the hallway. The RP shift supervisor indicated that a change would be submitted.

Errors associated with Table U of EOP 8 were previously documented in inspection report 50-461/91006. Errors included an area radiation monitor which did not have a remote alarm, and inconsistencies between associated procedures and Table U. Inspection report 50-461/96003 documents weakness in management oversight of the AR/PR system and in maintaining the AR/PR consistent with the USAR. Identification of more problems with the AR/PR system, the EOPs, and the USAR indicated that a thorough review was not done in response to previous errors.

c. Conclusions

The AR/PR detectors and channels listed on the EOPs were not correct. The errors did not impact operational response because operations relied on RP to provide local radiation readings, rather than the EOP table. However, Technical Specification 5.4.1.b required that written procedures shall be established, written, and maintained covering EOPs, and the failure to revise EOP-8 with correct information was considered a violation (50-461/96009-10).

R4 Staff Knowledge and Performance in RP&C

R4.1 Knowledge of Radiation Work Permit Requirements

a. General Observation

During observation of the control rod drive (CRD) overhaul, the inspector identified that the RP technician was not aware of all the requirements of the radiation work permit (RWP). The technician did not know that RWP 1155 required personnel in direct contact with the control rod drives to wear ring dosimeters. The inspector verified that personnel working on the CRD did have the appropriate dosimetry.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on November 23. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observation
IP 71001:	Licensed Operator Requalification Program Evaluation
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-461/96009-01	NOV	Inadequate NSPS bus outage checklist procedure
50-461/96009-02	NOV	Failure to maintain suppression pool temperature log
50-461/96009-03	NOV	Watchstanding credit for SROs in non-TS positions
50-461/96009-04	NOV	Inadequate corrective action for safety tagging errors
50-461/96009-05	NOV	Failure to follow procedure during EDG testing
50-461/96009-06	IFI	Follow-up on EDG synchronization relay check problems
50-461/96009-07	NOV	Untimely performance of UHAs and implementation of corrective actions
50-461/96009-08a		Apparent violation. Inadequate corrective action for FW check valve LLRT failures
50-461/96009-08b		Apparent violation. Inadequate procedure for FW check valve test.
50-461/96009-09	NOV	Failure to follow contamination control procedure
50-461/96009-10	NOV	Failure to revise ECPs with correct information

PERSONS CONTACTED

Licensee

W. Connell, Vice President
P. Yocum, Manager - Clinton Power Station
D. Thompson, Manager - Nuclear Station Engineering Department
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LIST OF ACRONYMS

ANSI	American National Standards Institute
AR/PR	Area Radiation/Process Radiation
C&I	Controls and Instrumentation
CFR	Code of Federal Regulations
CPS	Clinton Power Station
CR	Condition Report
CRD	Control Rod Drive
DRP	Division of Reactor Projects
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EIN	Equipment Identification Number
EOP	Emergency Operating Procedure
FW	Feedwater System
HX	Heat Exchanger
LASS	Line Assistant Shift Supervisor
LER	Licensee Event Report
LLRT	Local Leak Rate Testing
LPCS	Low Pressure Core Spray System
MSIV	Main Steam Isolation Valve
NAD	Nuclear Assessment
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
PDR	Public Document Room
RAT	Reserve Auxiliary Transformer
RHR	Residual Heat Removal
RP	Radiation Protection
RP&C	Radiation Protection and Chemistry
RPM	Revolutions per Minutes
RT	Reactor Water Cleanup System
RWP	Radiation Work Permit
SASS	Staff Assistant Shift Supervisor
SLC	Standby Liquid Control System
SRM	Shift Resource Manager
SRO	Senior Reactor Operator
SX	Shutdown Service Water
TS	Technical Specifications
UHA	Use History Analysis
USAR	Updated Safety Analysis Report