UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-413/95-19 and 50-414/95-19

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242

Docket Nos.: 50-413 and 50-414 License Nos.: NPF-35 and NPF-52

Facility Name: Catawba Nuclear Station Units 1 and 2

Inspection Conducted: August 6, 1995 - September 2, 1995

Inspectors: R. V. Crlenjak 9/26/95
for R. J. Freudenberger, Senior Resident Inspector Date Signed
per telecon 9/26/95
P. A. Balmain, Resident Inspector
R. L. Watkins, Resident Inspector
J. Zeiler, Resident Inspector

Approved by: R. V. Crlenjak 9/26/95
R. V. Crlenjak, Chief Date Signed
Projects Branch 3
Division of Reactor Projects

SUMMARY

Scope: This resident inspection was conducted in the areas of plant operations, maintenance, engineering and plant support. As part of this effort, backshift inspections were conducted.

Results: In the plant operations area, review and execution of the Unit 1 loss of load runback circuitry, troubleshooting and compensatory actions were thorough and effective (paragraph 3.a). Although effective, actions to compensate for an increasing reactor coolant pump seal leak-off trend were not timely (paragraph 3.b).

In the maintenance area, an Unresolved Item was identified pending licensee evaluation of corrective actions associated with a containment integrity issue (paragraph 4.b).

In the engineering area, a weak safety perspective was evidenced by the absence of a prioritized approach to resolving an optical isolator reliability issue (paragraph 5.a). Initial actions to resolve water in the lube oil of a safety injection pump were not consistent with the potential safety consequences of the condition (paragraph 5.b). Once brought to management's attention, appropriate actions were taken.

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In the plant support area, more conscientious radworker practices may have prevented personnel contaminations; however, evaluation of the cause of the contaminations was thorough and planned corrective actions were appropriate (paragraph 6).

REPORT DETAILS

1. **PERSONS CONTACTED**

Licensee Employees

B. Addis, Training Manager
*S. Coy, Radiation Protection Manager
*J. Forbes, Engineering Manager
*G. Ford, Safety Review Group Engineer
W. Funderburk, Work Control Superintendent
*T. Harrall, IAE Superintendent
D. Kimball, Safety Review Group Manager
*W. McCollum, Catawba Site Vice-President
*W. Miller, Operations Superintendent
K. Nicholson, Compliance Specialist
M. Patrick, Safety Assurance Manager
*G. Peterson, Station Manager
R. Propst, Chemistry Manager
D. Rogers, Mechanical Superintendent
*Z. Taylor, Regulatory Compliance Manager
*D. Tower, Regulatory Compliance Engineer

* Attended exit interview.

Other licensee employees contacted included technicians, operators, mechanics, security force members, and office personnel.

Acronyms and abbreviations used throughout this report are listed in the last paragraph.

2. **PLANT STATUS**

a. Operational Status

Both units operated at essentially full power for the entire report period.

b. Inspections and Activities of Interest

Inspections were conducted by specialist inspectors from the NRC Region II office as follows:

Report	Dates	Subject	Lead Inspector
95-15	8/7-18/95	Integrated Performance Assessment Program	W. Rogers

During the report period, the Operations Superintendent resigned his position due to a medical condition. Effective September 1, Ashok Bhatnagar, formerly a manager in the onsite engineering department, assumed the Operations Superintendent position.

3. **PLANT OPERATIONS** (NRC Inspection Procedure 40500 and 71707)

Throughout the inspection period, control room observations and facility tours were conducted to observe operations activities in progress. During these inspections, discussions were held with operators, supervisors, and plant management. Some operations activity observations were conducted during backshifts. Licensee meetings were attended by the inspector to observe planning and management activities. The inspections evaluated whether the facility was being operated safely and in conformance with license and regulatory requirements. In addition, the inspection assessed the effectiveness of licensee controls and self-assessment programs in achieving continued safe operation of the facility.

The following items were reviewed in detail.

a. Main Turbine Runback Initiated Alarms Received on Both Units

During this inspection period the inspector observed troubleshooting activities performed under work order 95067117 to investigate the cause of main turbine runback alarms that occurred on both units. Control room operators observed a slight decrease in generator electrical output when the alarms occurred, which indicated that an actual runback signal was being processed and not a spurious signal to the annunciator system. The alarms occurred twice on Unit 1 (July 31 and August 24) and once on Unit 2 (July 5). The alarms were of a very short duration, and only the alarm that occurred on August 24 was active long enough (approximately 1 second) to determine the portion of the runback circuitry that initiated the signal.

The licensee determined that a likely cause of the alarms was electrical noise in one of the runback circuits. The licensee reviewed work activities performed during the times when the runback alarms occurred and has not conclusively found an activity that could have induced the alarms. A vendor was contacted to perform non-intrusive noise measurements on the runback circuits, and the licensee performed voltage measurements on each of the runback inputs to determine if the inputs had degraded.

Following the receipt of the August 24 runback, the licensee initiated a test plan to troubleshoot the Unit 1 loss of load runback circuit. The inspector observed the Plant Operations Review Committee's review of the test plan and 10 CFR 50.59 evaluation developed for the troubleshooting. The inspector observed that the licensee established clear compensatory measures and contingencies for the troubleshooting. The inspector also observed that the licensee's pre-job briefing prior to the troubleshooting was thorough. Although the cause of the short duration runback signals was not determined, the inspector considered the licensee's review and execution of the Unit 1 loss of load runback circuitry troubleshooting and compensatory actions to be thorough and effective at minimizing the risk of initiating a transient on the unit.

b. Reactor Coolant Pump 2B Operation With High #1 Seal Leakoff Flow

During this inspection period the licensee completed several actions to reduce or stabilize the NCP-2B reactor coolant pump #1 seal leakoff flow. In November 1994 the NCP-2B #1 seal leakoff flow rate began to increase from a stable leakoff flow of approximately 3.8 gpm. The normal operating range for the leakoff flow is from 1 to 5 gpm when the reactor coolant system is at operating pressure. Following a forced outage in March 1995 the NCP-2B #1 seal leakoff flow trend began to increase at a faster rate. In June 1995 the licensee took action to replace the seal water injection filters, which reduced the seal leakoff flow but did not reduce or stabilize the increasing trend. Seal leakoff flow continued to increase and approached the operating limit of 5 gpm in July 1995.

The licensee and NCP seal vendor determined that the cause of the high seal leakoff flow is particle deposition on the seal faces. Actions taken during this inspection period included cleaning up water in the reactor makeup water storage tank and the boric acid tank, decreasing the volume control tank operating temperature, and increasing the #1 seal leakoff flow upper limit from 5 gpm to 5.5 gpm. The inspector reviewed the 10 CFR 50.59 safety evaluations associated with the minor modification to reduce the volume control tank temperature and the temporary station modification to increase the seal leakoff flow operating limit and verified that the evaluations were appropriate.

These actions have been effective in reducing the NCP-2B #1 seal leakoff flow. The licensee's current projections indicate that the current seal leakoff flow will stay within the revised operating limit until the unit is shutdown in October 1995 for a refueling outage. The inspector concluded that, although the licensee's actions were effective, they were not timely since evidence of the increasing seal leakoff flow trend was observed beginning in November 1994 and significant implementation of actions to minimize the leakoff flow was not completed until August 1995.

4. **MAINTENANCE** (NRC Inspection Procedures 62703, 61726 and 92902)

Throughout the inspection period, maintenance and surveillance testing activities were observed and reviewed. During these inspections, discussions were held with operators, maintenance technicians, supervisors, engineers and plant management. Some maintenance and surveillance observations were conducted during backshifts. The inspections evaluated whether maintenance and surveillance testing activities were conducted in a manner which resulted in reliable, safe

operation of the facility and in conformance with license and regulatory requirements.

The following items were reviewed in detail.

a. Control Room Ventilation System Trip

On July 24, 1995, during a yearly calibration of the Control Room Area Ventilation and Chilled Water 'B' chiller temperature switch (CNOYC TS9208B) under predefined WO 95054460, the licensee found the switch out of calibration at 24.5°F; the trip setpoint's allowable range is 32.0°F to 34.0°F. The switch was then calibrated to 33.6°F per procedure IP/0/A/3190/01B, Calibration Procedure for Train B Safety-Related YC Instrumentation.

On July 24-26, tube cleaning work was performed on the 'B' chiller. In early morning of July 27, after the work was completed, the chiller tripped twice during functional testing. The control room was notified that the temperature switch appeared to be out of calibration. Predefined WO 95058153-01 was issued for the calibration of the switch. The calibration was performed by a SPOC crew, who determined that the switch was in calibration per IP/0/A/3190/01B. However, an IAE crew performed the calibration again later that same day and determined that the switch was out of calibration at 37.8°F. Corrective WO 95058243 was initiated for the replacement of the switch, and the new switch was calibrated to 32.8°F under WO 95058153-01. After the switch had been replaced, the system successfully completed functional testing and was returned to operable status within the time period specified in the TS action statement.

The inspector questioned why the calibrations performed by the SPOC crew and the IAE crew yielded conflicting results. The licensee indicated that the personnel involved with both calibration checks were appropriately qualified for the task. However, during switch calibration, a time delay inherently exists because the switch does not respond immediately to the change in temperature within the test apparatus. Therefore, temperature must be decreased slowly so that an accurate trip setpoint reading can be obtained.

The inspectors reviewed IP/0/A/3190/01B and found that no specific guidance for calibrating the switch and decreasing ramping temperature slowly is provided in the calibration checklist. The licensee indicated that inducing a slow temperature change when using the test equipment was considered skill of the craft. The licensee initiated PIP 0-C95-1357 to further evaluate the discrepant results yielded by the two groups performing the calibration. The inspector considered this planned follow-up appropriate for determining if actions are necessary to ensure that the SPOC crews maintain appropriate skills to operate measuring and test equipment.

b. Containment Pressure Control System Pressure Transmitter Failure

At roughly 8:00 a.m. on August 23, during a semi-daily surveillance, Unit 1 control room operators noticed that one of four Containment Pressure Control System pressure indications on the Operator Aid Computer was incongruent with the other three indications. They determined that the instrument, a Containment Spray pressure transmitter, NSPT5270, was not functioning and declared the associated pressure channel of Engineered Safety Features Actuation System for the CPCS inoperable at 9:10 a.m. The channel was tripped within one hour as is required by TS 3.3.2, and valves NS12B, NS15B, and NS38B were declared inoperable in accordance with the licensee's interpretation of TS 3.3.2, Table 3.3-3. As a result, the associated train of the NS system was declared inoperable, and the unit entered a 72-hour action statement for TS 3.6.2.

A work request was generated to investigate the failure and repair the transmitter. The pressure transmitter manual isolation valve, which had not been qualified per Appendix J requirements, was closed in preparation for troubleshooting. At around 4:10 p.m., on August 23, technicians opened the penetration's test-tee, which formed a portion of the qualified containment integrity boundary. Soon afterwards (approximately 10 minutes), control room operators recognized during discussions with the technicians that, because the unqualified manual isolation was being relied upon as the containment barrier, containment integrity was not being maintained. The unit entered TS 3.6.1.1, which required that containment integrity be restored within one hour or that the unit be in hot standby within the next six hours.

To exit the shutdown action statement, the licensee promptly performed a Type C leak rate test on the manual isolation valve associated with the failed transmitter as well as the manual isolation valves paired with three other transmitters on the same penetration. The valves were successfully tested for containment integrity, and the unit exited the TS action at 7:20 p.m. The unit remained in a 72-hour action statement because the pressure channel associated with the failed transmitter was still tripped. The transmitter was replaced on August 24, and CPCS/NS train 'B' were declared operable at 6:35 p.m.

A challenge to containment integrity associated with testing and calibrating the transmitters in CPCS penetrations had been documented recently in PIP 2-C95-0506 and LER 50-414/95-02. On August 31, 1995, the NRC issued Non-cited Violation 50-413,414/95-18-01: Inadequate procedures for calibrating containment pressure instrumentation. According to the LER, procedures used for calibrating containment pressure transmitters were placed on hold pending completion of planned corrective actions, which included procedure changes and Type C leak rate tests of the penetration manual isolation valves. The licensee had begun to implement long-term corrective actions. The manual isolation valves for four other penetrations (2 on Unit 1 and 2 on Unit 2) had been Type C leak rate tested. The valves associated with the penetration that incurred the transmitter failure had been planned for testing the day before it failed. The test was postponed because it required that CPCS be declared inoperable, which adversely impacted the PRA matrix since train 'B' of the NS system was already inoperable.

The manual isolation valve was closed when the test-tee was opened, and it was subsequently successfully tested and qualified to Appendix J requirements; therefore, the safety significance of this event was minimal. The licensee is conducting an evaluation to determine why the corrective actions associated with the initial containment integrity issues were not effective in preventing recurrence. This item is unresolved pending the licensee's completion of the evaluation and will be tracked as URI 50-413,414/95-19-01: Evaluation of ineffective corrective actions associated with containment integrity issue.

c. Unit 2 Standby Makeup Pump Testing

On August 8 the inspector observed surveillance testing of the Unit 2 Standby Makeup Pump. The testing was performed per procedure PT/2/A/4200/07C, Standby Makeup Pump #2 Performance Test, to meet the requirements of TS 4.7.13.3.b, Standby Shutdown System.

The inspector verified that prerequisite requirements were met before the test was performed. During this review the inspector observed a requirement to verify the gas charge on pump suction and discharge pulsation dampeners and questioned if the dampeners were being preconditioned prior to surveillance tests. The inspector verified by reviewing maintenance work order documentation for the past year that the pulsation dampeners did not require any additional gas charging prior to the surveillance tests and were not being preconditioned to support testing.

Procedure PT/2/A/4206/06, Leak Rate Determination for NV System, was performed concurrently with the standby makeup pump run. During discharge piping valve manipulations to support the leakage determination, NLOs performing the test questioned a sudden change in the sound of the operating pump. Discussions with the NV system engineer revealed that this response was expected. The inspector also questioned whether or not the valve manipulations could result in the introduction of unfiltered water from the standby makeup system into the reactor coolant pump seals. The inspector determined from discussions with the system engineer and review of the test restoration sequence for these surveillances that water would not be injected into the reactor pump seals during this evolution. The inspector did not identify any discrepancies during standby makeup pump testing and verified that surveillance test acceptance criteria were met.

d. (Closed) IFI 50-413,414/93-31-01: Resolution of Emergency Diesel Generator Outage Issues

This item contained two parts. Part A involved high turbocharger vibration causing non-emergency trips of the 1B Emergency Diesel Generator. Part B involved the tripping of the output breakers while operators were attempting to phase the Emergency Diesel Generators to their respective busses.

Part A was further addressed in NRC Inspection Report 50-413,414/93-34 and left open because of continuing load swings on the 1B Emergency Diesel Generator at normal power levels. Inspection Report 50-413,414/95-03, paragraph 4.a, describes the licensee's actions to adjust the governor droop circuit, resolving this issue.

Licensee evaluation of the cause of the tripping of the output breakers while operators were attempting to phase the Emergency Diesel Generators to their respective busses (Part B) revealed that several corrective actions were necessary. Synchronizing relays were calibrated to have consistent tolerances, training material was revised to match in-plant conditions, and simulator synchronizing relay tolerances were narrowed to match plant conditions. Following these corrective actions, the issue has not recurred. This item is closed.

e. (Closed) Violation 50-413/93-34-02, Delayed Corrective Actions for High RHR Pump Vibrations

This violation involved the licensee's delayed corrective actions in assessing the operability of the 1A RHR pump when pump vibration entered the Inservice Testing required action range during operation of the pump for residual heat removal while the reactor coolant system was in reduced inventory conditions. The inspector reviewed the violation response dated March 3, 1994.

The inspector verified that Site Directive 3.1.14, Operability Determination, was revised to incorporate pump vibration limits to use when making operability determinations and provide instructions for operators to apply these limits for any flow conditions that may occur. The inspector verified by reviewing training history reports and training materials that mechanical and component engineers were provided Inservice Test Program refresher training, which included specific training on vibration requirements. The inspector verified that position specific training guidelines were revised to include specific Inservice Testing training. The inspector verified by reviewing training history reports and training material that engineering training incorporates requirements on the proper use of the operability determination process. In addition, the licensee reviewed appropriate methods to use when collecting informal data. This item is closed.

f. (Open) IFI 50-413,414/93-26-04: Controls for Amount of Leak Sealing Material Injected

During a previous review of the licensee's on-line leak sealant repair program, the inspector questioned the use of a 2:1 compression ratio factor when calculating the amount of leak sealant material to be injected for a given repair activity. This factor was being applied to the calculated volume (based on geometry) of the cavity being filled and effectively doubled the allowable amount of sealant material that could be injected.

The licensee reported that this factor was an approximation that was used to account for several sealant material losses during the initial injection phase, including: 1) shrinkage of the sealant material as gases and solvents are released, 2) compression of air and fibers entrained in the sealant material, and 3) corrections for sealant extrusion losses during the injection. The licensee was unable to provide any test information or other documentation to support the basis for using this doubling factor and indicated that it was based on personnel experience with the sealant material and repair activities. Based on the differences in viscosity of the variety of sealant materials used and diverse applications under which leak sealant repairs may be conducted, the inspector determined that this factor may not be conservative in limiting the possibility that sealant might be extruded into a system. The inspector determined that further review of the basis for the 2:1 compression factor was required to resolve this issue.

5. **ENGINEERING** (NRC Inspection Procedures 37551 and 92903)

Throughout the inspection period, the inspectors reviewed engineering evaluations, root cause determinations, and modifications. During these inspections, discussions were held with operators, engineers, and plant management. The inspection evaluated the effectiveness of licensee controls in identifying and appropriately documenting problems, as well as implementing corrective actions.

The following items were reviewed in detail.

a. Optical Isolator Failure

On August 2, 1995, during PT/1/A/4450/05B, Containment Air Return Fan 1B and Hydrogen Skimmer Fan 1B Performance Test, the hydrogen skimmer fan started before the fan's suction isolation valve (1VX2B) opened. The technicians secured the fan, the Containment Air Return and Hydrogen Skimmer system was declared inoperable, and Unit 1 entered a 72-hour TS action statement.

During troubleshooting, the licensee determined that a start signal to the fan was allowed to pass through a digital optical isolator (DOI 1F033), which should have been open to block the signal. The test procedure required a "Valve VX2B Open" signal to be simulated as a permissive for the fan to operate. The start signals to the fan and the damper were to be generated three minutes after the permissive was satisfied, and timers in the circuitry were designed to delay actual component initiation for approximately nine minutes. However, the fan received the first (permissive) signal and started before the damper opened, six minutes after the start signal was generated. Both the fan and the damper should have actuated nine minutes after the start signal was generated. On August 3 the DOI was replaced. The performance test was successfully performed and the system was declared operable.

Catawba Nuclear Station has incurred optical isolator failures in the past. Specifically, on February 21, 1995, the Unit 2 reactor tripped from full power when a DOI failed and caused the 'B' MSIV to close. Issues associated with the failure history of DOIs have been documented in Inspection Reports 50-413,414/95-07 and 95-13. The licensee had attributed previous failures to unreliable capacitors within the DOIs. Components in "critical" applications (i.e. applications in which their failure could cause a reactor trip, induce a plant transient, or prevent the unit from achieving or maintaining safe shutdown) were tested on Unit 2 and, if necessary, replaced before the unit restarted from the MSIV failure and subsequent reactor trip. Similar components were tested in Unit 1 applications.

Because of the decreasing reliability of these components, the licensee decided to replace all DOIs fed from AC power that perform control functions with newer, more reliable replacement DOIs. These DOIs were scheduled for replacement in the upcoming unit outages (10/95 for unit 2 and 6/96 for unit 1) and the following operating periods.

The DOI in the Containment Air Return and Hydrogen Skimmer system (1F033) was in a safety-related application, but had not been assigned any priority in the replacement schedule. The inspectors identified a number of DOIs that provide control functions from the Standby Shutdown Facility, which, according to the plant's Individual Plant Examination, has a high contribution to overall plant risk. The inspector discussed with the licensee the lack of prioritization of optical isolator testing and replacement as a function of accident mitigation or PRA, and questioned the licensee's confidence in the reliability of DOIs in safety applications that had neither been tested nor scheduled for near-term replacement. The licensee indicated that the schedules would be reevaluated based on each associated component's (component receiving control signals from the DOI) safety significance and vulnerability to single failure.

The inspector concluded that the licensee's safety perspective on long term resolution of this issue was weak because there had been a lack of cooperative effort among component engineering, systems engineering, and operations to generate a prioritized approach to resolving the DOI failure trend in safety applications as well as applications critical to operation.

b. Water Intrusion Into Safety Injection Pump Lube Oil

On August 22 during separate maintenance and operations activities the licensee identified significant amounts of water in the 1B and 2B safety injection pump lube oil reservoirs. The licensee determined that approximately 2 quarts of water was in the 1B NI pump lube oil reservoir and 1 quart of water was in the 2B reservoir. Water in the lube oil reservoirs could potentially degrade the ability of the safety injection pumps to function as required. The inspector reviewed the results of the licensee's operability determination and investigation of the cause of the water intrusion.

The licensee identified water in the 1B NI pump lube system as part of a maintenance activity to resample the NI pump oil as a followup to water observed during the NI pump outage planned maintenance performed during the Unit 1 refueling outage in February 1995. Water identified in the 2B NI pump oil system was discovered when an NLO questioned a high oil reservoir level during routine equipment rounds. Following discovery of the water, the licensee took immediate actions to drain and refill the oil systems of both pumps. The licensee subsequently identified that the lube oil piping contained low points that could collect water. The lube oil systems were drained again, piping was disassembled and cleaned to remove additional water and then reassembled and refilled. The licensee also inspected the bearings in both NI pumps. No evidence of damage or unusual wear was identified on the lubricated bearing surfaces on either pump. Significant corrosion was identified on the 1B thrust bearing support ring, which indicated that the water had been in the lube oil system for several months. This bearing was replaced before the pump was returned to service. The licensee determined that all bearings on the 2B pump were acceptable and did not replace them.

The licensee's investigation concluded that the probable cause of water intrusion into the 1B NI pump lube oil system was decontamination activities in the pump room in March 1995 following the Unit 1 refueling outage. A breather cap was missing from the 1B lube oil reservoir vent pipe, which could have allowed the introduction of water into the system. The inspector reviewed decontamination personnel statements and also reviewed the licensee's normal decontamination techniques with radiation protection personnel to determine how the decontamination process could have allowed water into the pump lube oil system. The inspector observed that the licensee used a garden hose for a general spray down of the 1A pump room, which introduced a large volume of water into the area. Spray from the hose or splashing from the walls could have been directed into the oil reservoir. The licensee concluded that the most probable cause of water entering the 2B pump was from the equipment drain system in the room backing up. This in discussed further in paragraph 6.

As a result of these investigations the licensee suspended decontamination activities involving the use of garden hoses or pressure washers until the proper use of this equipment is reviewed. The licensee has repaired clogged portions of the NI pump room equipment drain system and initiated procedure changes to prevent future equipment drain backups.

The inspector observed portions of the 1B NI pump thrust bearing replacement. In addition following the maintenance activities, the inspector verified by reviewing completed surveillance tests that both pumps successfully passed inservice tests.

The licensee's operability evaluation determined that both NI pumps would have performed their safety function for emergency core cooling. The evaluation was thorough, comprehensive and utilized input from a number of outside consultants and industry experts. Since the safety function of the pumps was not impaired by the water in the bearing lubrication systems, the inspector concluded that the safety significance of this issue was minimal. Nonetheless, for the 1B NI pump in particular, licensee actions in pursuing resolution to water identified in the oil in February 1995 was not consistent with the potential safety consequences of the condition.

c. (Closed) LER 50-413/93-008, Reactor Trip and Auxiliary Feedwater System Automatic Start

The reactor trip and ESF actuation occurred on July 18, 1993, because of a failure of the primary and backup processors located in the portion of the Unit 1 Digital Feedwater Control System (DFCS) associated with the 1A Steam Generator level control, main feedwater pump speed control and main feedwater control valve position control. Previously, on July 17, 1993, the backup processor failed. During maintenance activities performed on July 18 to replace the failed backup processor, the primary processor also failed, which resulted in the loss of automatic control functions and control board indications for the 1A steam generator. Operator actions taken in response to the faulty indications led to the reactor trip.

The inspector reviewed the licensee's implementation of planned corrective actions for this event. A review of the licensee's immediate corrective actions was documented in NRC Inspection Report 50-143,414/93-21. The inspector verified that the vendor has included DFCS engineering personnel on correspondence related to the DFCS. The inspector verified from reviewing requisition documentation that previous revision spare DFCS processors were removed from stock and upgraded to acceptable revisions. The inspector verified that the licensee developed procedures IP/0/B/3222/93A, DFCS Start Up and Check Out, and IP/0/B/3222/93B, DFCS General Maintenance and Troubleshooting, to ensure that DFCS start up and repairs meet design engineering specifications. The licensee's review of other possible failure modes that could affect DFCS revealed only one additional failure mode because of improper manufacture of the circuit card frames. The inspector verified by reviewing modification work order documentation (CE-4287 and CE-4288) that the card frames were replaced. These modifications also incorporated software changes to ensure proper processor initialization upon startup. The inspector verified that alarm response procedures and Mode 3 checklists were revised to include requirements to initiate Model work orders to troubleshoot DFCS trouble annunciators. This item is closed.

6. **PLANT SUPPORT** (NRC Inspection Procedure 71750)

Throughout the inspection period, facility tours were conducted to observe activities in progress. Some tours were conducted during backshifts. The tours included entries into the protected areas and the radiologically controlled areas of the plant, including emergency response facilities. Observations included assessments of radiological postings and work practices. During these inspections, discussions were held with radiation protection and security personnel. The inspections evaluated the effectiveness of the programs to assess whether activities were performed safely and in conformance with license and regulatory requirements.

Contamination of the Nuclear Sampling Laboratory

On August 15, 1995, highly contaminated liquid was found in the Nuclear Sampling (NM) Laboratory. The licensee determined that the source was a backed-up sink in the lab. On August 16, 1995, a highly contaminated mixture of water, sludge, and resin was found on the floors, walls, and ceiling of the 2B NI pump room; this is potentially related to intrusion of water into the 2B NI pump lube oil system (discussed in section 5.b of this report). The licensee determined that the source of the contamination was backflow through the NI pump seal leak-off drain. Additionally, Radiation Protection found water droplets on the poly covering the sink in the Restricted Instrument Shop. However, since the sink was covered, the room was not contaminated.

The inspectors reviewed PIP C94-1393 which is associated with a similar event that had occurred in 1994. The NM lab sink had backed up whenever the Floor Drain Tank was drained and the Spent Resin Storage Tank was sparged, concurrently. The NM Lab sink, Restricted Instrument Shop sink and the drain for the NI pump seal leakoff all drain to a common header before being deposited into the Waste (WEFT) Sump B. Therefore, sparging the SRST while draining from the FDT allowed nitrogen from the sparger to force backflow through the drain lines, resulting in contamination of the NM room. The corrective action consisted of procedural changes to prevent FDT draining and SRST sparging at the same time.

The licensee determined that the root cause of the recent contamination was not that the draining and sparging were performed simultaneously, but that there was a restriction in the drain line from the FDT to the WEFT Sump B. The restriction was caused by large amounts of solid material from the floor drains, which were cleaned using high-pressure water in the summer of 1994, blocking the drain lines. The constant draining of the FDT had gradually contributed to the amount of solid material in these drain lines. Instead of passing through the clogged drain lines and into the WEFT Sump B, water and sludge collected in the drain lines. The nitrogen from the SRST sparger was taking the path of least resistance and forcing this residual water and sludge into the NM lab sink (as well as the NI pump Liquid Radwaste (WL) equipment header drain line and the Restricted Instrument Shop sink).

A chemistry technician had entered the lab to perform routine Reactor Coolant System sampling at 8:00 a.m. on August 15. She noticed that a local sample monitor was alarming but assumed that it was from gas in the lab and did not notify Radiation Protection. In addition, she spotted a puddle of water on the NM lab sink counter, but did not associate that with the alarming sample radiation monitor. Because Radiation Protection was not contacted and the spill was not cleaned up, three other people were contaminated in the NM lab later that morning. More conscientious radworker practices may have prevented these contaminations.

As part of their corrective action, the licensee has begun to pump the contents of the FDT to the WEFT rather than the WEFT Sump B. They also plan to remove the debris from the drainage lines between the FDT and the WEFT Sump B. Under consideration are a potential modification to add clean-out ports on drain lines and the use of an isolation valve to prevent sparging from affecting the drain header. The licensee's evaluation of the contamination events was thorough and planned corrective actions are appropriate.

7. EXIT INTERVIEW

The inspection scope and findings were summarized on September 7, 1995, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection findings listed below. No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

Item Number	Status	Description and Reference
URI 413,414/ 95-19-01	Open	Evaluation of ineffective corrective actions associated with containment integrity issue (paragraph 4.b).
IFI 413,414/ 93-26-04	Open	Controls for Amount of Leak Sealing Material Injected
IFI 413/414/ 93-31-01	Closed	Resolution of Emergency Diesel Generator Outage Issues
VIO 413/93-34-02	Closed	Delayed Corrective Actions for High RHR Pump Vibrations
LER 413/93-008	Closed	Reactor Trip and Auxiliary Feedwater System Automatic Start

8. ACRONYMS AND ABBREVIATIONS

AC - Alternating Current
CFR - Code of Federal Regulations
CPCS - Containment Pressure Control System
DFCS - Digital Feedwater Control System
DOI - Digital Optical Isolator
ESF - Engineered Safety Feature
FDT - Floor Drain Tank
gpm - gallons per minute
IAE - Instrument and Electrical
IFI - Inspector Followup Item
IST - Inservice Testing
LCO - Limiting Condition for Operation
LER - Licensee Event Report
MSIV - Main Steam Isolation Valve
NCP - Reactor Coolant Pump
NI - Safety Injection
NLO - Non-licensed Operator
NM - Nuclear Sampling
NS - Containment Spray
NV - Chemical and Volume Control System
PIP - Problem Investigation Process
PRA - Probabilistic Risk Assessment
R&R - Removal and Restoration (Tagging Order)
RHR - Residual Heat Removal
SPOC - Single Point of Contact
SRST - Spent Resin Storage Tank
TS - Technical Specifications
URI - Unresolved Item
VC - Control Room Area Heating and Ventilation
WEFT - Waste Evaporator Feed Tank
WL - Liquid Radwaste
WO - Work Order
YC - Chilled Water System