U. S. NUCLEAR REGULATORY COMMISSION

REGION III

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License Nos:	NPF-37, NPF-66
Report No:	50-454/96-04, 50-455/96-04
Licensee:	Commonwealth Edison Company (ComEd)
Facility:	Byron Generating Station, Units 1 & 2
Location:	Opus West III 1400 Opus Place Downers Grove, IL 60515
Dates:	April 5 - May 21, 1996
Inspectors:	H. Peterson, Senior Resident Inspector N. D. Hilton, Resident Inspector Melvin S. Holmberg, Regional NDE Inspector Caius Dodd, Headquarters NDE Inspector Steven Orth, Regional RP Inspector Ross Landsman, Regional Project Engineer
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EXECUTIVE SUMMARY

Byron Generating Station, Units 1 & 2
NRC Inspection Report 50-454/96-04, 50-455/96-04

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. This report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections by a regional radiation specialist and two non-destructive testing inspectors.

Operations

- The licensee identified their unanalyzed and potentially unsafe practice of cross-connecting two or more safety injection accumulators. This is an unresolved item pending further NRC review of the licensee's analysis (Section O2.1).

- Operators and system engineering demonstrated good communication and coordination during Unit 1 control rod testing (Section O1.2). Operators performed numerous complex evolutions without error during the Unit 1 shutdown (Section O4.1).

Maintenance

- Unusual plant conditions due to planned maintenance imposed additional challenges to the operators. An increased number of compensatory actions was necessary to assure safe and proper mitigation of a plant casualty (Section M1.1).

- Some weak foreign material exclusion (FME) work practices were observed during the emergency diesel generator overhaul; licensee FME procedures for this work were ineffective (Section M1.2).

Engineering

- NRC questions prompted licensee personnel to follow NRC requirements governing reactor vessel shell weld examinations. This issue was considered an inspection follow-up item (Section E1.1).

- Inservice inspection personnel detected and conservatively evaluated steam generator (SG) tube degradation and effectively executed eddy current testing (ET) of the Unit 1 steam generators (Section E4.1).

- The predominant mode of SG tube degradation detected by the licensee this outage was circumferentially oriented outside diameter stress corrosion cracking in the tube roll transition regions. The second most common form of SG tube degradation detected was primary water stress corrosion cracking in the tube roll transitions and U-bend regions (Section E4.1).

Plant Support

- Radiological controls to reduce the exposure to personnel and maintain total outage dose within administrative goals were effective (Section R1.1).

- The radiation protection staff provided good support and oversight, with some minor exceptions. However, several workers demonstrated weaknesses in removing protective clothing (Section R4.1).

- Site Quality Verification audits of radiation protection were effective in identifying areas of improvement and weaknesses in the licensee's program. The licensee's evaluation, documentation, and resolution of a failure to properly control access to a thermoluminescent detector irradiator was thorough. This licensee-identified and corrected violation is being treated as a non-cited-violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (Section R7).

Report Details

Summary of Plant Status

Unit 1 shut down on the first day of the period for a scheduled refueling outage, B1R07. Significant work included steam generator inspection and sleeve repairs, emergency diesel generator inspections and governor replacements, reactor vessel 10 year inservice inspection, and reactor coolant system (RCS) resistance temperature detector (RTD) bypass removal.

Unit 2 operated at or near full power the entire inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent inspections of plant operations. In general, the conduct of operations was professional and conservative; however, one exception is detailed in maintenance section M1.1 below. In particular, the inspectors noted improvement in the personnel error rate during this period.

O1.2 Good Coordination between Operations and Engineering during NRC Bulletin 96-01 Required Control Rod Testing (Unit 1)

a. Inspection Scope (71707)

As a result of industry events involving slow control rod drop times, NRC Bulletin 96-01 requested the licensee to perform, among other things, control rod drop testing and control rod drag force measurements.

b. Observations and Findings

The inspectors observed good communication and coordination between operators and engineers during the control rod drop testing and drag force measurement testing. The licensee performed these activities for Unit 1 per NRC Bulletin 96-01.

c. Conclusions

The inspectors considered the control rod testing a demonstration of good communication and coordination between operations and system engineering. During the rod drop tests and drag force measurements no abnormalities were noted by the licensee.

02 Operational Status of Facilities and Equipment

02.1 Cross-tied Safety Injection Accumulators

a. Inspection Scope (71707)

The licensee notified the NRC that they had operated the safety injection accumulators outside their design basis by cross-connecting the accumulators. The inspectors reviewed the licensee's notification and immediate corrective actions.

b. Observations and Findings

The licensee identified that the safety injection accumulators were occasionally cross-connected during periodic fill or pressurization operations. Additionally, accumulators were cross-connected to equalize level or to verify proper level indicator operation. Equalizing level lengthened the period between filling accumulators, thereby reducing safety injection pump run time.

The licensee procedure for filling accumulators allowed any combination of the four to be cross-connected. This generally required less than one hour.

The licensee's evaluation of this cross-connecting practice was that it potentially made the safety injection accumulators inoperable, under certain conditions. The analysis concluded that the licensing basis would be met with two accumulators cross-tied but not with four cross-tied.

Technical Specification (TS) 3.5.1 requires each accumulator to be operable. The action requirement was within 1 hour restore an inoperable accumulator to operable or be in hot standby within the next 6 hours.

The licensee's immediate corrective action included a procedure change to prohibit the cross-connection of any safety injection accumulators.

At the end of the period, the licensee had not completed a root cause investigation.

c. Conclusions

The inspectors considered this issue an unresolved item pending further NRC review of the licensee's analysis and Licensee Event Report (50-454/455-96004-01(DRP)).

04 Operator Knowledge and Performance

04.1 Good Operator Performance during Unit 1 Shutdown and Refueling Preparations (71707)

a. Inspection Scope

The inspectors observed Unit 1 shutdown and cooldown activities, including preparations for refueling activities.

b. Observations and Findings

The inspectors observed good operator performance during the Unit 1 shutdown, cooldown, reactor vessel drain and cavity fill activities. The licensee held thorough briefings before each major evolution. Shift supervision constantly observed the reactor operators and senior operations management was frequently present. Clear, formal communications in the control room existed throughout the shutdown evolutions.

Additionally, the inspectors observed good coordination between fuel handlers and operators. The lack of personnel errors during the shutdown and reactor vessel drain activities further demonstrated good communications and professional performance.

c. Conclusions

The inspectors concluded that operators performed numerous complex evolutions without error during the Unit 1 shutdown.

08 Miscellaneous Operations Issues

08.1 ComEd/Union Labor Dispute Follow-up

This labor dispute was previously addressed in Inspection Report 95013 and pertained to the licensee's strike contingency plans. Subsequently, a new concern was raised by a licensee employee about the qualifications of the senior reactor operators (SROs) to safety operate the plant. Previously, the inspectors verified that Byron had a sufficient number of actively licensed SROs to continue plant operations while meeting the minimum staffing requirements per the technical specifications. In this inspection, the inspectors noted that all SROs demonstrated their competency and qualifications during periodic requalification training and examinations.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Shutdown Risk Management (Unit 1)

a. Inspection Scope

On April 3 and 4, 1996, the inspectors reviewed the licensee's shutdown risk assessment for the Unit 1 refueling outage, B1R07.

b. Observations and Findings

The inspectors noted that the schedule had placed one train (out of two) of emergency power for Unit 1 out of service before the refueling cavity level was raised to 23 feet. At this time, the reactor cavity level was at the reactor vessel flange, and the reactor was being cooled by shutdown cooling. The reactor had been shutdown for approximately four days, and decay heat was such that the reactor coolant would boil in about 16 minutes without shutdown cooling. Shutdown cooling was being provided by one residual heat removal (RH) pump. Both RH pumps were operable, as required by the technical specifications.

The licensee had scheduled maintenance periods to begin on Unit 1 DC Battery Bus 111 approximately four days prior to the refueling cavity level reaching 23 feet. Additionally, the 1A DG had maintenance scheduled to begin at about the same time as the DC battery bus work.

The licensee did not perform any quantitative risk assessment for the conditions scheduled. Licensee personnel stated that a quantitative risk assessment using PRA data was planned.

The licensee held High Level Activity briefs and reviewed information with operators on the contingency plans necessary to mitigate a loss of off-site power during these unusual plant conditions on Unit 1.

The licensee executed the schedule and both the AC and DC power sources for the 1A RH pump were inoperable for approximately four days prior to raising cavity level to 23 feet.

In addition to this activity, on May 5, 1996, a repair on the 1A essential service water (SX) pump strainer with the 1B DG, DC Bus 112, and the OC service water (WS) pump inoperable due to other planned work, again placed additional challenges on the operators. The inspectors were concerned about the potential effect to Unit 2 if a loss of off-site power to Unit 1 occurred. WS pumps A and B are both electrically supplied from the Unit 1 non-vital bus. Due to the inoperable OC WS pump, a loss of off-site power would result in a total loss of service water to the station. Therefore, a loss of off-site power to Unit 1 would result in a Unit 2 reactor trip. The licensee's problem identification program also noted this concern; they resolved it by

noting that contingency plans existed. The inspectors emphasized this concern to the licensee during the exit meeting.

c. Conclusion

The inspectors concluded that the unusual plant conditions imposed by the outage schedule produced challenges to the operators which could have been avoided by less aggressive scheduling. An increased number of compensatory actions was necessary to assure safe mitigation of a loss of off site power. The licensee's decision to adopt scheduling plans which required these compensatory actions was less conservative from a safety perspective than a more extended schedule.

M1.2 Foreign Material Exclusion (62703)

a. Scope

The inspectors reviewed a new foreign material exclusion (FME) procedure and identified FME issues during the refueling outage.

b. Observations and Findings

The licensee implemented a new foreign material exclusion (FME) corporate procedure on selected work packages. Additionally, the licensee identified several FME deficiencies during the outage.

The inspector observed work on the 1A Diesel Generator (DG) on April 10, 1996. FME was controlled using corporate procedure SMP-M-04, "Foreign Material Exclusion." The inspector observed the following inside the posted FME area, while the DG crankcase was open:

- a small amount of poorly marked transparent material was used for FME barriers. The inspector noted that poorly or unmarked transparent material is difficult to identify if the material inadvertently enters a system.
- eye glasses did not have lanyards. The inspector noted that eye glasses without a lanyard have the potential to fall into an open system.
- large amounts of tools and parts for the engine overhaul were scattered throughout the area, covering most of the room floor. The inspector noted that tool and part control provides additional material accountability and protection from foreign material entering an open system.

The inspector discussed these concerns with maintenance department supervisors and management. Maintenance supervision and management was not concerned because any lost articles would be identified in a diesel generator close-out inspection. After stating that they were not concerned about these observations, the licensee decided to move the FME area boundary to the crankcase.

On April 18, 1996, the inspector observed a modification in progress on 1SI8811A, Unit 1 Containment Recirc Sump Outlet Isolation. The modification involved work on a valve vent line. The inspector noticed that there was not a FME barrier plug installed in the cut off vent line. The opening was near the 1A safety injection (SI) pump suction. The inspector questioned a quality control technician working a few feet away as to the requirements for a FME barrier. The quality control (QC) technician did not believe a barrier was required. The inspector then questioned a welder working near the opening and the welder agreed a barrier should be installed. The welder immediately placed a plug in the hole.

Additionally, the licensee identified nine examples of foreign material entering an open system during the outage. The licensee either removed the material or evaluated the material as acceptable without removal. Examples include:

- a rag found blocking an oil line in the main generator hydrogen seal oil float tank.
- a cotter pin dropped in the spent fuel pool.
- a compression fitting ferrule dropped in the reactor vessel.

At the end of the inspection period, the licensee was preparing a revision for the corporate foreign material exclusion procedure and trending FME concerns. Additionally, maintenance department management conducted tours specifically looking for FME issues.

c. Conclusion

The inspector concluded that the FME work practices were weak in the diesel generator overhaul and modification of 1SI8811A. No equipment failures due to improper FME controls were identified.

III. Engineering

E1 Conduct of Engineering

E1.1 Inservice Inspection (ISI) Unit 1 - Review of Program

a. Inspection Scope (73051)

Inspectors reviewed the inservice inspection program and its implementation, for compliance with technical specifications, American Society of Mechanical Engineers Boiler and Pressure Vessel (ASME) Code and NRC requirements.

b. Observations and Findings

The licensee inspected less than 90 percent of each reactor vessel shell weld. Part 50 of Title 10 of the Code of Federal Regulations (10 CFR 50.55a(g)(6)(ii)(A)(2)) requires at least 90 percent of each weld to be

inspected. The inspectors identified that no relief from the 90 percent inspection coverage requirement or alternative examinations pursuant to 10 CFR 50.55a(g)(6)(ii)(A)(5) had been submitted to the NRC prior to performing the reactor vessel examination. The inspection interval had not yet expired at the time the inspectors identified this apparent oversight. The licensee committed to submitting a letter to the NRC, describing the scope and methods used for performing the reactor vessel examination to comply with 10 CFR 50.55a(g)(6)(ii)(A)(5) requirements.

The steam generator (SG) inspection scope exceeded technical specification requirements and NRC Generic Letter (GL) 95-03 commitments.

c. Conclusions

NRC questions prompted licensee personnel to follow NRC requirements governing reactor vessel shell weld examinations, indicating that opportunities existed for improvement in oversight of the ISI program. This issue was considered an inspection follow-up item, pending submittal of the licensee's reactor vessel shell weld alternative examination request (50-454/96004-02(DRS)).

E3 Engineering Procedures and Documentation

E3.1 Inservice Inspection - Procedure Review

a. Inspection Scope (73052)

The inspectors reviewed the SG data analysis guidelines, ISI procedures and lists of equipment used during observed ISI activities for compliance with ASME Code and NRC requirements.

b. Observations and Findings

The licensee's analysis guidelines specified the use of terrain plots for analysis of eddy current testing indications. These guidelines met Generic Letter 95-03, "Circumferential Cracking of Steam Generator Tubes," commitments.

The equipment used for these inspections was listed as qualified for detection of anticipated tube degradation in accordance with the PWR Steam Generator Examination Guidelines (Electric Power Research Institute (EPRI) NP 6201, Appendix H, Revision 4) and met Generic Letter 95-03 commitments.

c. Conclusions

No violations or deviations were identified.

E4 Engineering Staff Knowledge and Performance

E4.1 Inservice Inspection - Observations of Work Activities and Data Review

a. Inspection Scope (73753 and 73755)

The inspectors observed ISI personnel and reviewed data recorded during ISI activities to determine compliance with ASME Code and NRC requirements. The NRC inspectors observed the following activities:

- Framatome Technologies, Rockridge and ZETEC personnel performing eddy current testing (ET) of SGs.

- Framatome Technologies personnel performing automated ultrasonic testing (UT) of the reactor vessel and nozzles from the inside surface using the ACCUSONEX acquisition and analysis system.

- ABB-Combustion Engineering (ABBCE) personnel performing cleaning and visual inspections of SG tubes in preparation for sleeving.

b. Observations and Findings

The licensee identified two Code reportable flaws in the reactor vessel circumferential shell welds and one Code reportable flaw was detected in an outlet nozzle safe end weld. Flaws recorded were dispositioned as acceptable per IWB-3500 of ASME Boiler and Pressure Vessel Code Section XI, "Inservice Inspection."

The licensee classified more than one percent of the SG tubes in each of the Unit 1 SGs as defective based on eddy current inspection results. The steam generators were categorized as C-3 in accordance with technical specification 4.4.5.2. The predominant numbers of defective tubes (to be repaired) and degradation modes were:

- 3481 tubes with circumferential or mixed mode degradation in tube roll transitions at the top of the tubesheet were identified using a three coil rotating probe (+Point™, 0.080 inch diameter and 0.115 inch diameter pancake coils). Affected tubes were located in the hot leg side of the Sgs, except for three indications detected in the cold leg side of SG C. Eddy current data analysis guidelines indicated a history of circumferential indications caused by outside diameter stress corrosion cracking in this area.

- 322 tubes with axial oriented degradation in tube roll transitions at the top of the tubesheet were identified using a three coil rotating probe. Eddy current data analysis guidelines indicated a history of axial indications caused by primary water stress corrosion cracking in this area.

A crack-like indication was detected in the U-bend region of SG B during the initial 20 percent inspection of each SG row 1 and 2 U-bends. A rotating +Point™ probe was used. The inspection scope was expanded to include a rotating +Point™ probe inspection of 100 percent of row 1 and 2 U-bends in each SG and 20 percent inspection of row 3 U-bends in SG B. These inspections detected five tubes in row 1 and 2 U-bends of SG B with circ indications. One of these tubes also contained an axial U-bend indication. In addition, this inspection detected one row 1 tube in SG C with an axial U-bend indication. Licensee personnel considered these indications to be primary water stress corrosion cracking. These indications were not identified during bobbin coil inspections performed on U-bends during previous outages. The licensee documented the U-bend cracking and planned to stabilize and plug SG tubes with circumferential cracking in the U-bends.

The licensee identified that stabilizers were installed in tube 39-98 in SG C and tube 4-108 in SG D. Licensee review of prior outage eddy current data indicated that these tubes should not have had stabilizers installed (no repairable degradation had been recorded). Licensee personnel determined tubes at adjacent locations (39-97 in SG C and 5-108 in SG D) had circumferential degradation and presumably did not have stabilizers installed prior to plugging. The licensee documented this condition. Licensee personnel reported Westinghouse had performed an analysis to demonstrate that the plugged tubes, 39-97 and 5-108 (without stabilizers), were satisfactory for continued operation until scheduled SG replacement. Tubes 39-98 (SG C) and 4-108 (SG D) were scheduled to be plugged.

Dents at tube support plate locations measuring greater than 5 volts (based on bobbin coil voltage) were required to be reinspected with a rotating pancake probe as part of the licensee's alternate plugging criterion for the tube support plate. A 0.115 inch diameter rotating pancake coil reinspection of a 15 volt dent in SG A (cold-leg side) detected a single axial crack at the 6th tube support plate, and the tube was scheduled to be repaired.

A loose part identified as a grinding tool head was found at the top of the tubesheet in SG B. This condition was documented and the licensee scheduled sleeving of tubes adjacent to the loose part, which could not be removed.

The presence of surface oxides on improperly cleaned SG tube surfaces for ABBCE TIG welded sleeves installed at Prairie Island Unit 1 had resulted in sleeve weld zone flaws (oxide inclusions, lack of fusion, weld suck-back). Preparations for installation of ABBCE TIG welded sleeves for Byron

Unit 1 included rotating wire brush cleaning and a post cleaning visual examination of SG tube surfaces to be welded. Inspectors noted that brush cleaning techniques appeared to be effective at removing SG tube surface oxides and the visual acceptance criteria for post cleaning visual examinations were well defined.

The licensee performed a reanalysis of previous outage eddy current data using ZETEC Eddynet95 software. The scope of this look-back included a 10 percent sample of the largest (based on voltage amplitude) circumferential indications detected in the A, B, and D SG tube roll transitions. In addition, all SG tubes in SG C with circ indications detected in the roll transition were compared to prior eddy current data for +Point™, 0.080 inch diameter and 0.115 inch diameter pancake coils. The inspectors noted the following about this:

- Eddy current data collected with the MIZ-30 acquisition equipment during the 1996 inspection had a better signal to noise ratio than ET data collected during the 1995 inspection using the MIZ-18 acquisition equipment.

- Eddynet95 software was effective at minimizing the effects of SG roll transition geometry on the ET data with an Axial Line Filter, enhancing resolution of flaw signals.

- Eddynet95 software allowed lissajous figures in both the axial and circumferential direction to be examined, and allowed windowing of flaw indications, which improved data analysis.

- Differences in calibration standards (between the 1995 and 1996 inspections) contributed to a positive bias of about 15 percent for ET flaw signal voltages recorded in the 1996 inspection. This bias could affect flaw growth predictions based on ET indication voltage amplitudes.

- The primary reasons for detection of indications during the 1996 outage (that were present in earlier outages but not reported) appeared to be enhancements in ET equipment hardware, software and analyst training.

The results of this eddy current data look-back and an ET data look-back with header information removed (identifying the date recorded and location of SG tubes e.g., a "blind look-back") were presented to NRR staff during a meeting held at NRC headquarters, Rockville, MD on May 14, 1996. Licensee personnel concluded the following for circumferential indications in the SG roll transitions:

- 78 percent of the indications were present during the 1995 outage.

- 23 percent of the indications were present during the 1994 outage.

- The large numbers of indications detected during the 1995 and 1996 outages were due to enhancements in ET equipment hardware, software and analyst training.

- The voltage growth rate of indications appeared to be slow. This was based on an observed increase of 0.56 volts (for the maximum voltage amplitude indication) during the 1994 to 1996 operating period (voltages recorded from the 0.080 inch diameter pancake coil).

c. Conclusions

ISI personnel detected and conservatively evaluated SG tube degradation and effectively executed eddy current testing (ET) of the Unit 1 steam generators (SGs). The predominant mode of SG tube degradation detected this outage was circumferential oriented outside diameter stress corrosion cracking in the tube roll transition regions. The second most common form of SG tube degradation detected was primary water stress corrosion cracking in the tube roll transitions and U-bend regions.

E5 Engineering Staff Training and Qualification

E5.1 Inservice Inspection - Qualifications of NDE personnel

a. Inspection Scope (73753)

Inspectors reviewed Framatome Technologies, Rockridge Technologies and ZETEC personnel qualifications and certifications for compliance with ASME Code, SNT-TC-1A (American Society of Non-destructive Testing Recommended Practice) and applicable NRC requirements.

b. Observations and Findings

Eddy current data analysts were certified in accordance with EPRI NP 6201 Appendix G requirements for qualified data analysts, which met GL 95-03 commitments.

c. Conclusions

Personnel certification records were properly documented and reviewed by the licensee personnel and the Authorized

Nuclear Inservice Inspector (ANII) for ASME Code, Section XI inspections.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Refueling Outage Radiological Controls (Unit 1)

a. Inspection Scope (83750)

The inspectors reviewed radiological controls implemented during the Unit 1 refueling outage, including as-low-as-reasonably-achievable (ALARA) dose goals and results and source term reduction. The inspectors reviewed the following high dose work (either in progress or in planning and preparation):

- resistance temperature detection (RTD) modification
- steam generator (SG) tube inspection and repairs
- inservice inspection (ISI)

The inspectors also discussed specific radiation protection (RP) controls with the ALARA staff and RP technicians.

b. Observations and Findings

Current outage dose and work progress appeared well controlled and within the licensee's projected outage dose goal. As of April 25, 1996, outage dose was about 95 rem (0.95 Sv) with an outage dose goal of 292 rem (2.92 Sv). The RTD modification was near completion with about 48.8 rem (0.48.8 Sv) of exposure. Based on the results of eddy current examinations, the scope of the SG tube repair work was significantly expanded from the initial estimate. As of April 24, 1996, the licensee planned to sleeve about 3600 SG tubes and revised the dose projection to 70 rem (0.70 Sv). As a result of reduced dose during other evolutions, the outage dose goal of 292 rem (2.92 Sv) remained unchanged by the increased SG scope.

The licensee tracked job performance daily by a comparison of actual to planned radiation work permit (RWP) dose and hours. Additionally, the licensee compared daily and accumulated outage dose to the projected outage dose estimates. The RP staff reviewed these indicators and verified that outage dose was well controlled and that work progress was well understood.

The licensee implemented effective ALARA measures to reduce source term and outage dose. During the reactor shutdown,

the licensee effectively controlled reactor chemistry to reduce the source term. Through controlled boric acid and hydrogen peroxide additions, the licensee induced a controlled cobalt dissolution that removed 241 curies (Ci) (8.92 terabecquerels (TBq)) of cobalt-60 and 4 Ci (0.15 TBq) of cobalt-58 from the reactor core. The licensee also realized immediate reductions in dose rates from the removal of the RTD manifold. The inspectors observed pre-job ALARA briefings which emphasized RP controls and hazards. The licensee also trained personnel on mockups to improve worker efficiency and reduce dose for the SG sleeving work and RTD modification.

c. Conclusion

The licensee implemented effective radiological controls to reduce the exposure to personnel and maintain outage dose within administrative goals. Source term reduction and ALARA program implementation were effective in reducing worker exposures.

R4 Staff Knowledge and Performance in RP&C

R4.1 Radiation Worker Practices and Radiation Protection Staff Oversight and Support

a. Inspection Scope (83750)

The inspectors made frequent tours of the radiological restricted area (RRA) and observed worker performance and understanding of radiological hazards and controls. The inspectors also observed RP staff support and oversight.

b. Observations and Findings

The inspectors observed satisfactory RP staff support and oversight of work in progress, with some minor exceptions. The licensee provided three control points for evolutions occurring inside the containment missile barrier (IMB): SG control point, RTD control point, and general IMB control point. Control point RP staff were cognizant of those personnel performing activities in their particular areas. The inspectors noted a lack of overall control and understanding of IMB activities, including the overlap of work areas and the interaction of work groups. Additionally, RP staff did not appear to aid workers (described below) who were having difficulty removing protective clothing. Finally, the inspectors noted two radiological postings which were in accordance with NRC requirements but could be confusing to workers.

During tours of the RRA, the inspector noted that workers understood radiological hazards and requirements. Personnel working inside of the reactor containment IMB were knowledgeable of radiological conditions and demonstrated good ALARA practices. Personnel generally used low dose waiting areas effectively; however, the inspectors identified a large number of persons waiting for an extended period of time at the IMB control point (a low dose area). The workers were waiting for materials which were not currently available. The workers did not expect to obtain the materials quickly. Following the inspectors' observations, the workers acknowledged that they should not remain in the reactor containment if material was not obtained within a reasonable amount of time.

The inspectors noted an increase in the number of personnel contaminations. The licensee's investigations of the contaminations attributed a large fraction of these to contamination of the modesty garment changing area, which may have partly resulted from the removal of protective clothing. Following the inspectors' observations of weaknesses in protective clothing removal techniques, the licensee implemented the following actions to ensure that personnel properly removed protective clothing: increased RP staff oversight at the containment exit step-off pads, reduced the number of personnel allowed to enter the step-off pad area at any one time, and increased the involvement of the training coordinator for contract personnel.

c. Conclusions

The RP staff provided good support and oversight, with some minor exceptions. Radiation workers had an acceptable understanding of radiological hazards and controls. However, several workers demonstrated weaknesses in removing protective clothing, increasing the potential for personnel contaminations.

R5 Staff Training and Qualification in RP&C

The inspectors reviewed the qualifications of the recently appointed (4/1/96) chemistry supervisor and lead chemist. Although American National Standards Institute (ANSI) N18.1-1971, "Selection and Training of Nuclear Power Plant Personnel" required, in part, that a non-licensed supervisor have a minimum of four years experience in the discipline supervised. The chemistry supervisor had no chemistry experience. The chemistry supervisor had broad oversight with the functional position of manager (as defined in ANSI N18.1-1971), for which he was qualified. Due to the chemistry supervisor's lack of chemistry experience, licensee management stated that the lead chemist was given the

responsibility for system chemistry decisions and technical based decisions affecting the chemistry department. The position of supervisor (as defined in ANSI N18.1-1971) corresponded to the licensee's lead chemist position, based on his direct responsibilities for department activities. The inspectors verified that the lead chemist had the experience required by ANSI N18.1 for the supervisor position. Discussions with the chemistry supervisor and lead chemist indicated that the assignment of responsibilities was well understood; no problems with these assignments were identified.

R7 Quality Assurance in RP&C Activities

a. Inspection Scope

The inspector reviewed site quality verification (SQV) assessments of the RP program and the associated findings and observations.

b. Observations and Findings

The SQV department identified a problem concerning the control and radiological postings of the thermoluminescent dosimeter (TLD) irradiator room. On March 11, 1996, the TLD coordinator left the door ajar during irradiation. The irradiator had a control device to ensure that personnel could not be in the area during source exposures, in accordance with 10 CFR 20.1601. Additionally, 10 CFR 20.1902(b) required that a licensee post a high radiation area (HRA) with a conspicuous sign or signs. However, the licensee determined that the HRA posting was not conspicuously visible. The licensee immediately corrected the problem and implemented long term corrective actions. The licensee also evaluated the generic implications with respect to control and posting of HRAs.

c. Conclusions

The scope and detail of audits appeared effective in identifying weaknesses in the licensee's program, including radioactive material labeling and pre-job planning. The licensee's evaluation, documentation, and resolution of the TLD irradiator issue was thorough. This licensee-identified and corrected violation is being treated as a non-cited-violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

V. Management Meetings

X1 Exit Meeting Summary

On May 21, 1996, the inspectors presented the inspection results to licensee management. 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.

PARTIAL LIST OF PERSONS CONTACTED

K. Graesser, Site Vice President
K. Kofron, Station Manager
D. Wozniak, Site Engineering Manager
T. Gierich, Operations Manager
P. Johnson, Technical Service Superintendent
E. Campbell, Maintenance Superintendent
M. Snow, Work Control Superintendent
D. Brindle, Regulatory Assurance Supervisor
T. Schuster, Site Quality Verification Director

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 62703: Maintenance Observations
IP 61726: Surveillance Observations
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 73051: Inservice Inspection - Review of Program
IP 73052: Inservice Inspection - Review of Procedures
IP 73753: Inservice Inspection
IP 73755: Inservice Inspection - Data Review and Evaluation
IP 83729: Occupational Exposure During Extended Outages
IP 83750: Occupational Radiation Exposure

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-454/455-96004-01 URI	safety injection accumulator cross connection issue
50-454/455-96004-02 IFI	reactor vessel ISI letter submittal

Closed

None

Discussed

None