U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-263/90002(DRP)

Docket No. 50-263 License No. DPR-22

Licensee: Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

Facility Name: Monticello Nuclear Generating Station

Inspection At: Monticello Site, Monticello, Minnesota

Inspection Conducted: January 7 through February 17, 1990

Inspectors: J. E. Hard
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Approved By: R. W. DeFayette, Chief
Reactor Projects Section 2B

3/22/90
Date

Inspection Summary

Inspection on January 6 through February 17, 1990 (Report No. 50-263/90002(DRP))
Areas Inspected: A routine, unannounced inspection by the resident inspectors and others, of previous inspection items; operational safety verification; maintenance; surveillance; onsite followup of operational events; review of the Containment Integrated Leak Rate Test (CILRT) results. A special, announced followup inspection of deficiencies cited in an Emergency Operating Procedures Special Team Inspection was also performed.
Results: One violation was identified for failure to revise a procedure to properly control activities during the CILRT (Paragraph 8.a). The containment passed the integrated leak rate test. A total of 11 open items, 3 TMI items, and 8 EOP inspection team items were closed out during this inspection period. Two unresolved items were identified: the improper sizing of replacement Rotork valve operators and a logic deficiency in the EFT high radiation fan subsystem. The unit remained at power throughout the entire inspection period.

DETAILS

1. Persons Contacted

C. E. Larson, Vice President, Nuclear Generation
L. R. Eliason, General Manager, Nuclear Plants
*D. D. Antony, Plant Manager
M. H. Clarity, Assistant to the Plant Manager
#B. D. Day, General Superintendent, Engineering & Rad. Prot.
D. E. Nevinski, General Superintendent, Operations
W. J. Hill, General Superintendent, Maintenance
R. L. Scheinost, General Superintendent, Quality, Security & Admin.
G. L. Hudson, Superintendent, Security
P. A. Johnson, Manager, Monticello Nuclear Projects Department
P. H. Kamman, Manager, Nuclear Operations, Quality Assurance
T. M. Parker, Manager, Nuclear Support Services

The inspector also contacted other licensee employees including members of the technical and engineering staffs, and the reactor and auxiliary operators.

*Denotes licensee representatives attending the resident inspectors' exit meeting.

#Denotes licensee representatives attending the EOP Special Inspection Team exit meeting.

2. Licensee Action on Previous Inspection Findings (92701, 92702)

a. (Closed) Unresolved Item (263/88003-04): Licensee Interpretation of Technical Specifications 3.5.D and 3.5.C.

The licensee had declared the High Pressure Core Injection (HPCI) system inoperable on 2/7/88. TS 3.5.D.2 for the HPCI system states that reactor operation is permissible only for the succeeding seven days provided that all of the Automatic Pressure relief systems, the RCIC system, both of the Core Spray Systems, and the LPCI subsystem and the containment cooling mode of the Residual Heat Removal (RHR) system are operable. On 2/8/88, the licensee initiated WRA 88-5575 to perform work on RHR Service Water (RHRSW) control valve CV-1728. Because of this work, the licensee declared RHRSW "A" loop inoperable in the Shift Supervisors log, and CV-1728 was declared inoperable on the WRA. Although this was considered a conservative interpretation of TS 3.5.C.2 and 3.5.C.3 for RHRSW operability, it raised a question of whether this action violated the TS 3.5.D.2 requirement for containment cooling mode of the RHR system operability.

The inspector reviewed the licensee's TS interpretation document that was reviewed by the Operations Committee on 3/17/88. In this interpretation document the licensee referenced an evaluation summary dated 3/7/88, performed by GE stating GE's position on Monticello TS interpretation 3.5.D.2-1.

The licensee also reviewed TS 3.5.C, "Containment Cooling Capability" and stated that the Containment Cooling mode of RHR is considered operable when the following is available:

(1) 2 RHRSW pumps in one RHRSW subsystem with a flow path through the associated RHR heat exchanger, and,

(2) 2 RHR pumps with a flow path through the same RHR heat exchanger as the available RHRSW subsystem, and,

(3) At least one RHR flow path for Drywell spray, and

(4) At least one RHR path for torus cooling.

The above represents the minimum containment cooling capability. This capability was met. This matter is closed.

b. (Closed) IE Information Notice 87-56: Improper Hydraulic Control Unit (HCU) Installation at BWR Plants.

This Information Notice was provided to alert licensees to a potential problem that could affect the ability of the HCUs to control the positioning of the control rods in the event of an earthquake. Specifically, if a sufficiently large number of HCU frame bolts are missing or loose, a Safe Shutdown Earthquake could result in damage affecting the ability of the CRD system to control the position of the control rods.

The licensee initiated WRA 87-04779 in response to this IEIN to record the as-found and as-left torque of all HCUs hold-down bolts. The results of this effort indicated five bolts with "0" as-found torque, but none missing. GE was contracted to perform an analysis of the HCUs based on the as-found data to determine whether an unsafe condition existed. GE's response, dated December 1988, states that "a safety problem has never existed at Monticello which is related to the HCU dynamic qualification." This matter is closed.

c. (Closed) IE Information Notice 87-59: Potential RHR Pump Loss.

This Information Notice was provided to alert licensees of potential problems with safety injection pumps having common recirculation lines. This Information Notice was superseded by NRC Bulletin 88-04, Potential Safety Related Pump Loss.

The licensee responded to this bulletin on July 8 and December 13, 1988. The NRC acknowledged these submittals in correspondence dated December 28, 1988 indicating that the licensee had fulfilled the requirements of the Bulletin. This matter is closed.

d. (Closed) IE Information Notice 88-09: Reduced Reliability of Steam-Driven Auxiliary Feedwater Pumps caused by instability of Woodward PG-PL Type Governors.

This information Notice was provided to alert licensees to continuing problems affecting the reliability of steam-driven auxiliary feedwater pumps caused by instability problems with Woodward governors.

Although Monticello does not use the governor in question the licensee performed an extensive evaluation of the Woodward governors for their steam-driven RCIC and HPCI systems.

The material condition of the governor valves are maintained by the use of preventive maintenance procedures on a periodic basis. The HPCI and RCIC systems are given quick starts from cold conditions monthly, their steam inlet lines are continuously drained to prevent condensate buildup, and the governor control systems are evaluated following each refueling outage through testing. In addition, the HPCI and RCIC governors are sent to Woodward for maintenance.

e. (Closed) Violation 88-027-02 (DRP): Failure to Adhere to Procedures That Govern the Calibration of Measuring and Test Equipment (M&TE).

The licensee immediately took action to place all torque multipliers in a segregated and locked area within the machine shop.

The licensee has revised the existing administrative procedures to address what to do with equipment that is past due for calibration. The inspector reviewed Administrative Control Document 4 ACD-06.04, Calibration and Control of Inspection, Measuring, and Test Equipment, Rev. 6. Among the changes made in response to this violation are:

- Section 6.4.6.a, "M&TE overdue for recalibration shall be clearly identified and/or segregated to prevent its use."
- Section 6.7.5, "M&TE found out of calibration shall be clearly identified and/or segregated to prevent its use."
- Section 6.7.5.a, "A Defective Tag, Form 4102 should be used for tagging purposes."

The inspector also reviewed Administrative Work Instruction 4 AWI-06.04.02, Calibration and Control of Inspection, Measuring, and Test Equipment, Rev. 2. Among the changes made to this AWI was:

- Section 6.4, "M&TE that is past its calibration date should be identified with a Defective Tag, and/or segregated to prevent its use. Such equipment shall be calibrated prior to use.

The inspector considers these corrective actions to be adequate and considers the violation to be closed.

f. (Closed) Violation 88-003-01 (DRP): Inadequate Work Controls Causes Undetected Loss of Power to Remote Alarm Panel.

The event involved the inoperability of the Fire Detection System Annunciator Panel for a sixty hour period without a patrolling fire watch in the plant. The cause of this event was inadequate work controls. A work procedure did not identify specific precautions to take to prevent the unintentional manipulation of the annunciator panel power switch. A contributing cause for not finding the power off was that the status of the panel was not routinely checked.

The licensee's corrective actions included; counseling of the personnel involved in the preparation of the work procedure on the proper considerations for controlling work activities around sensitive equipment; an hourly fire annunciator status panel check; presentation of this LER to the plant engineering staff; and establishment of a plant policy to control work activities in areas containing sensitive equipment.

The inspector verified that the above corrective actions had been taken. This item is closed.

g. (Closed) Violation 89-031-01 (DRP): Failure to Follow Procedures.

In response to this violation, the licensee made procedure adherence a specific job performance standard in NSP's Performance Measurement and Review System which applies to all Monticello plant employees. The licensee has also established a Procedure Quality task force to look at the ways that the quality of procedures can be improved. Part of the mission of the task force is to look at possible procedure quality improvements that can be made to make strict procedure adherence easier for the worker.

This item is closed.

3. Licensee Action on EOP Inspection Findings (92701)

a. Background

During the period July 11-22, 1988, an NRC inspection team performed an inspection (Inspection Report No. 50-263/88-200) to review the licensee's program for implementing Emergency Operating Procedures (EOPs) required by NUREG-0737 Supplement 1.

The Monticello EOP inspection team found that, although there were deficiencies in the EOP development and implementation processes that required prompt licensee management attention, the EOPs were technically correct and could be accomplished in the plant by operating shift personnel. The deficiencies noted during the inspection and cited in the Inspection Report were also communicated to the licensee through correspondence from W. O. Long, Project Manager for Monticello from the Office of Nuclear Reactor Regulation to T. M. Parker, Manager, Nuclear Support Services, Northern States Power Company, dated November 9, 1989. This correspondence detailed the following items noted as deficiencies in the original Inspection Report:

(1) The absence of a formal program for EOP maintenance, including Quality Assurance involvement

(2) Inadequate verification and validation of the C.5-3000 EOP Support Procedures

(3) Specific human factors deficiencies related to control room lighting and layout

(4) Discrepancies in plant labeling and nomenclature used to identify plant components within the body of procedures

(5) Inadequate verification of plant parameter data used in setpoint calculations

(6) An apparent training deficiency related to operator use of support procedures outside the control room

(7) Performance disparities between various shift crews in demonstrating use of EOPs. (The team observed that the performance of a recently qualified shift supervisor in implementing EOPs during simulator scenarios was sufficiently weak to constitute a safety concern. However, the team's concern was downgraded from a safety issue to identification of a programmatic weakness in the EOP training for newly qualified shift supervisors after conducting additional simulator observations of other operating crews. With the involvement and concurrence of NRC Regional and Headquarters management the licensee immediately undertook the actions necessary to address the problem)

(8) The Inspection Report noted that the licensee's containment venting procedures, while consistent with BWROG guidelines, were not supported with analyses for estimate of ducting failure, post-accident valve operability, and reactor building accessibility.

b. Follow-up Inspection Activities

(Closed) Item 1: There is no formal program for EOP maintenance, including Quality Assurance involvement.

Inspection Report 50-263/88-200 cited four examples of omission from the Monticello EOPs of general CAUTION notes with inadequate justification and/or appropriate alternative changes such as use of specific CAUTIONs. Also noted in the inspection report was an editorial error in EOP deviation documentation and the fact that flowchart guidance was deleted from the EPGs on the basis that flowcharts are not part of the submittal (to NRC). These findings led to the inspection team's review of the licensee's overall administrative control program for maintenance of EOPs.

After a review of all supporting program documentation, the inspectors concluded that no formal mechanism existed for the continuous maintenance of the EOPs, PSTG, Writer's Guide, or support procedures as required by Sections 6.2.0. through 6.2.4 of NUREG-0899. The inspectors reviewed the licensee's proposed administrative control document and concluded that it was, in its draft format, insufficiently detailed to meet the requirements of NUREG-0899. A licensee QA audit performed just prior to the team's arrival concurred with this assessment. While the absence of an administrative control program has not rendered the EOPs technically inadequate, largely due to the extensive involvement of plant staff, the inspectors cautioned the licensee that tight administrative control over the program was essential to continued technical adequacy of the procedures.

Since the time of the team inspection, the licensee has made significant progress in implementing formal controls for preparing and maintaining EOPs and EOP-related documents. The inspector obtained a copy of Administrative Control Document ACD-04.02 (Rev. 6 dated 5/25/89), and noted that it requires EOPs, including flowcharts, to be prepared and revised in accordance with the EOP Generation Manual (EOPGM). The inspector noted that whereas the EOPGM encompasses the BWROGs, Monticello Plant specific EPGs, Writer's Guide, Flowchart Writer's Guide, Verification Program, and Validation Program, and is invoked by ACD 4.2 Rev. 6 for guidance, the EOPGM itself is not administratively controlled. In response to this concern, the NSP EOP Systems Engineer produced a copy of a draft Rev. 7 to the Administrative Control Document. Rev. 7 was scheduled to go to the plant Operations Committee for approval the following week. It will establish formal administrative controls (i.e. for review, approval, record keeping) over the EOPGM.

Based on the inspector's observations and discussions with the licensee's EOP Systems Engineer, formal administrative, programmatic controls over EOP generation and revision existed and have been implemented. This item is closed.

(Closed) Item 2: Inadequate verification and validation of the C.5-3000 EOP Support Procedures.

The EOP inspection team noted deficiencies which were common to one or more of the EOP Support Procedures:

- Jumper wires used to bypass interlocks were not dedicated jumpers and were in daily use for plant testing and surveillances. Discussions with the operating staff indicated that there was no testing program for the jumpers and no periodic checks to verify jumper integrity. The staff explained that jumpers received visual inspections when they are used. The team recommended dedicated jumpers or periodic checks to ensure jumper operability is maintained.

- The procedures did not specify a requirement to obtain a jumper of appropriate size prior to leaving the control room area and entering the plant.

During the walkthroughs, inspectors noted that the EOPs included a caution that upon loss of instrument air to the Emergency Diesel Generators (EDGs) Dampers, their rooms could overheat and cause EDG failure. The team expressed its concern to the licensee that this situation was not consistent with the General Design Criterion No. 17 of 10 CFR 50, Appendix A, which requires a design for onsite electrical sources that can perform safety functions assuming a single failure. Also, during a situation requiring the use of EOPs, trained operators would be diverted to perform an action that could be eliminated by modifying the EDG ventilation dampers. The Licensee responded to the concern within 24 hours by taking the following actions:

- The dampers were blocked open

- The requirement to dispatch an operator was removed

- The licensee committed to complete a satisfactory, permanent modification of the dampers before the onset of cold weather.

The above findings indicated a need for improved validation and verification of C.5-3000 series procedures.

The inspector reviewed the modification package for the damper modifications, reviewed the licensee's actions relating the verification and validation of C.5-3000 support procedures, and verified the availability of dedicated jumpers.

The inspector visited the EDG rooms and confirmed that the EDG room dampers have been permanently modified and returned to service (although the modification has not yet been "closed out" due to the need for appropriate USAR changes). The modified dampers fail to

the safe (open) position. The modification package includes a safety analysis of the potential effects of the dampers being open during freezing weather.

The licensee EOP Systems Engineer stated that each of the C.5-3000 procedures has been subjected to a walkdown/validation and verification. The inspector noted that the validation/verification findings are documented in the licensee's EOP Program Manual - Volume 14.

The inspector visited the shift supervisor's office and noted a locked cabinet prominently marked "EOP Jumpers." The duty shift supervisor was requested to open the cabinet and spot-check one set of jumpers for a procedure specified by the inspector (C.5-3001). The inspector verified the presence of the correct number of jumpers and their proper labeling. This item is closed.

(Closed) Item 3: Specific human factors deficiencies related to control room lighting and layout.

During the EOP inspection the operators expressed concern that the EOP flowcharts may not be readable during loss of all offsite power. The inspection team investigated the emergency lighting system and found that it only illuminated the panels; there were no emergency lights which directly illuminated the central and rear areas of the control room where the flowcharts and other procedures would be used. Although there was no data on the light levels in the central and rear areas during loss of all offsite power, there was reasonable concern that the light levels might be too low for procedure legibility.

The space available for the operators to lay out the flowcharts was extremely limited. The area normally used at the simulator for the flowcharts was not available in the control room because it contained telephone equipment and would contain SPDS equipment. The inspectors recommended that the licensee identify a space in the control room that can be cleared during an emergency to support the use of the flowcharts, particularly when many are being used concurrently.

The binders used for the operating procedures (many of which will be used concurrently with the EOPs) were on several occasions observed to fall apart while the operator was using the procedure. The operator was then required to put the procedure back together and fix the binder, detracting from his participation in the emergency response. It was recommended that the use of another type of binding system be investigated. Further, all the operating procedures are in black binders. When several were laid on a work surface it was difficult to readily identify the desired procedure. The team recommended that binders should be marked on the outside.

During the simulator observation activities described in Section 3.2 and Appendix E of the Inspection Report, the following observations were relayed to the licensee:

- The shift supervisor was observed having difficulty locating the correct flowchart both in the installed rack and when all charts were out and in use. This difficulty appeared to result from the way the charts were marked. While some were marked for easy identification, others were not. Subsequent discussion indicated that the control room charts were marked differently from the simulator charts. In addition some charts were read vertically and some must be turned sideways, making the marking more difficult to read. The inspectors recommended all flow charts in both control room and simulator should be marked in large letters with number and title on the top margin and on the side margin. In addition, the licensee should consider enhancing the layout so that all charts are read the same way, either all vertically or all horizontally. The team noted that the flowchart labeling was corrected in the simulator prior to the end of the inspection.

- The reactor operator could not locate the C.5 volume for approximately one minute. The volume, which closely resembled all other volumes in appearance, was found out of the rack on the central desk. During discussion with that operating crew, the inspectors learned that the books in the control room were red and easier to distinguish. The inspectors recommended that the simulator volumes be identical to control room volumes in content, size, and markings in order to preclude negative training.

- The reactor operator could not locate the diesel generator operating procedure for about a minute. The section had been removed and was lying on another desk. The team recommended that the sides of the individual sections on the control room master copy (catalog rack) be clearly marked so if several sections were removed and lying on desks (the likely situation during an emergency) they would be clearly identifiable without the need for operators to pick up and open the cover of each one.

The inspector visited the main control room and made the following observations:

- A modification to add emergency lighting directly over the flowchart laydown area was in progress. (The lamps were installed while the inspector was onsite).

- A large, clear flowchart laydown area was made permanently available.

- EOP binders were appropriately marked on the outside and had locking devices to prevent them from falling apart.

- In the control room, EOP binders are stowed in two tiers, (whereas in the simulator room, they are stowed in a single tier). However, control room personnel were readily able to locate specific procedures when requested by the inspector. Colored tabs have been placed in the binders to facilitate their use.

- Some flowcharts are used horizontally and others vertically. However, this did not adversely impact their stowage or use.

Based on the inspector's observations, this item is closed.

(Closed) Item 4: Discrepancies in plant labeling and nomenclature used to identify plant components within the body of procedures.

The EOP inspection report identified numerous cases of temporary labeling in the control room and in the plant. Instances included penciling on concrete walls to identify dampers overhead in the ceiling area, masking tape to identify dampers, and "dymo" tape and magic markers used on control panels. The Monticello Detailed Control Room Design Review (DCRDR) identified widespread labeling problems in the control room and established a control room relabeling program to address all labels in the control room. The relabeling program was scheduled for the next refueling outage. Inspectors concluded that labeling in the control room for the procedures that were walked down was less than optimum, but that labels were not sufficiently confusing to impair the recognition and operation of a component, switch, or indicator. Some control room valves were labeled with both the Bechtel valve designation (not used by the procedure) and the plant designated number (used in the procedure). The control room duplicate valve number labeling was more significant than other inconsistencies since it forces the operator to read the extra number and may cause delay or confusion under the stress of an emergency. Labeling outside the control room was adequate except for specific cases noted for each procedure. The team concluded that damper labeling was inadequate and would cause difficulties in implementing Procedure C.5 - 3009 during normal and degraded lighting.

The procedures were not consistent with regard to specifying names for valves. Some valves are identified by name and number, some only with number, and the format for name and number varied from step to step and procedure to procedure. In some procedures, numerous valves were identified by number with no component name. The inspectors recommended to the licensee that full and consistent specification (name and number) of valve identify would reduce the probability of personnel error.

The inspector toured the control room and reactor building to review the licensee's actions. Those control room panels for which DCRDR modifications have been completed had no "dymo" tape markings. There were "dymo" tape identifications on the not-yet-modified panels. Laminated plastic markings have been provided for reactor building vent dampers in the vicinity of the concrete markings. The inspector concluded that significant improvement has been made in labeling consistency. The licensee stated that in the course of the revalidation and reverification walkdowns, inconsistent labels were noted and corrected.

Although DCRDR modifications are not yet completed, no additional follow-up action is considered necessary. This item is closed.

(Closed) Item 5: Inadequate verification of plant parameter data used in setpoint calculations.

The EOP inspection team reviewed the calculations in General Electric EPG, Appendix B, to evaluate the accuracy of the plant-specific input data, the reasonableness of the assumptions used for the calculations, the adequacy of the design controls, and the quality assurance oversight applied to the calculations.

The inspector determined that GE had performed the calculations in accordance with its QA program and that independent GE reviews were documented. The licensee, however, did not conduct a formal, documented independent review of the plant specific data provided to GE. A team member reviewed the numerous revisions of plant-specific data and concluded that accurate plant specific data had apparently been used in the GE calculations and that the questionable data did not appear to be significant variables in the applicable calculations.

The calculations established the limits and action decision points for the operators when using the EOPs. They also were used to validate assumptions in the EOPs. Given the safety significance of these calculations, the team recommended the following corrective actions.

- Conduct an independently verified validation of the input data as soon as practical
- Identify any deviations between the verified data and that used in the GE calculations
- Forward these deviations to GE for recalculation of the affected portions of Appendix C to the EPGS
- Revise the EOPs, if required, due to changes in the calculations

- Conduct a formal, documented quality assurance review of the GE calculations. Because of the safety significance of calculations supporting EOPs, standard periodic reviews of the vendor's quality assurance program may not be adequate to specifically address the validity of calculations in an EOP application.

The licensee's former EOP System Engineer stated that he performed a licensee review of the input parameters and calculations used by General Electric in preparation of the EOPs. However, since the documentation was lost, he had repeated the verification. All of the input parameters and approximately 60% of the calculations were independently verified by this independent review, and are documented in Volume 11 of the EOP program manual. No discrepancies were identified. The inspector verified the existence of this documentation. The 60% review of calculations is considered an adequate verification sample. This item is closed.

(Closed) Item (6): An apparent training deficiency related to operator use of support procedures outside the control room.

Although operators seemed well trained and adequately followed the EOPs during simulator and walkthrough observations, the inspectors identified lack of adequate training for EOP support procedures as a weakness. Although the support procedures (3000 series) were taught in the classroom they were not walked down in the plant. The operators who walked down these procedures for the inspection team had difficulty following the procedures and locating controls and components. This difficulty was in part due to improperly validated procedures, but absence of inplant training on the support procedures contributed to the inspector's broader concern over operator's ability to perform required activities outside the control room. The inspection team recommended that all operators receive inplant training in support procedures as one aspect of a comprehensive program to ensure operator ability to accomplish required activities outside the control room.

During interviews, the operators indicated that the inspection team's validation scenarios had taken them deeper into the flow paths than they experienced during requalification training. The training staff indicated that they had emphasized entry into the EOPs, which left less time to practice steps and go deeply into the EOPs. The inspection team recommended that the training staff incorporate complex scenarios into their training that force operators to move deeply into multiple flow paths.

As a result of the July 1988 inspection, Monticello operations personnel initiated a Training Enhancement Request to introduce more complex scenarios, involving multiple flow paths, into their simulator training program. In addition, the support procedures were validated as noted in Item 2 above. A member of the licensee's

training staff indicated that all lesson plans are being rewritten. EOP Day 2 of the requal cycle includes inplant use of EOP Support Procedures. In January of 1989 the licensee developed a new Lesson Plan "M 8114 L - 011 Rev. 0, EOP Supplemental Procedures C.5-3000 Series" to better familiarize operators with the purpose and use of the support procedures. In a letter dated March 16, 1989, NRC Region III evaluated the Monticello Requalification Program and concluded that it was satisfactory. (The letter noted certain programmatic concerns which are being independently followed-up.) Since the adequacy and acceptability of the operator requalification training program simulator scenarios are independently assessed in terms of operator performance during requal examinations, no further follow-up action relative to Inspection 88-200 is considered necessary. Based on the licensee having revalidated and reverified the support procedures and incorporated inplant use of EOP support procedures into the requal cycle, this item is considered closed.

(Closed) Item 7: Performance disparities between various shift crews in demonstrating use of EOPs were readily apparent.

During the simulator observations of the first two operating crews the inspectors noted a significant disparity between their levels of performance. While the first crew appeared well versed in the procedures and confidently and efficiently used the flowcharts to bring the simulated plant to a safe condition, the second crew, when faced with comparable simulated scenarios, demonstrated a lack of familiarity with the flowcharts that contributed to several incorrect decisions. The crew lacked an organized approach to emergency management, and failed to decisively address the emergency. The inspection team considered the observed weaknesses in the second crews' understanding and use of EOPs to represent a significant safety concern based on the conclusion that the observed crew would apparently be unable to respond adequately to an actual plant emergency using the EOPs.

Concern over this safety issue resulted in a request to the licensee for an opportunity to observe a third operating crew in the simulator. The observed ability of the third crew to efficiently and effectively use the EOPs compared favorably to the performance of the first crew. Further investigation of the significant difference between the performance of the first and third crews and that of the second crew revealed that the Shift Supervisor had recently been promoted to the key Shift Supervisor position from an RO licensed position that had only provided minimal exposure to flowchart EOPs and little opportunity to practice EOP usage in the supervisory role of the SRO licensed Shift Supervisor. Further, because of an absence, this Shift Supervisor had received relatively little of the flowchart training provided to recently promoted SROs prior to assuming management duties in the control room. The team concluded that the licensee failed to exercise proper managerial controls over the training and qualifications of key supervisory

licensed operators with primary responsibility for safe facility operation and protection of the public health and safety. Although the inspection team, with concurrence of regional and headquarters management, downgraded its concern from a safety issue to a concern over inadequate training, the team conveyed its greater concern to the licensee that management's decision to place a supervisor with inadequate training in the position of managing potential emergencies indicated the need for more effective management involvement in facility operation.

In response to the team's concerns the licensee immediately undertook an intensive training program to ensure adequate EOP training to all Shift Supervisors and the crews they supervise. The crew whose performance was observed to be weak received an additional 20 hours of simulator training and successfully completed a formal evaluation by licensee management prior to returning to licensed duties in the control room. A Region III licensing examiner observed the evaluation and determined that the crew performance was acceptable. All remaining operating crews were scheduled to receive similar training during the six week training cycle which concluded August 26, 1988.

Following the July 1988 EOP Team Inspection, the licensee initiated an intensive remedial training program for all shifts. (Ref: Letter from L. Eliason, NSP to G. Wright, NRC/RIII). The licensee indicated that records are available to document the training for all shifts. The inspector verified training center records for one of the six shifts.

(Closed) Item 8: Lack of analyses for estimate of ducting failure and for reactor building accessibility during containment venting.

Inspection Report No. 50-263/88-200 noted that the licensee has not performed calculations designed to establish a pressure limit for secondary containment ductwork which is part of the primary containment vent flow path. Concern existed that post-accident venting of primary containment could result in contamination of the secondary containment due to overpressurization of the ducting.

By letter dated October 31, 1989, the licensee committed to install a hardened vent system to provide a means to vent the containment without danger of rupturing the existing purge and vent piping. The hardened vent is to be installed about March 1993. Based on this commitment, this item is closed.

4. Operational Safety Verification (71707)

a. Routine Inspection

The inspector observed control room operations, reviewed applicable logs and conducted discussions with control room operators during

the inspection period. The inspector reviewed the use of hold and secure cards for the control of systems and electrical lineups.

Tours of the radwaste building, reactor building, intake structure, and turbine building, were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and work practices.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under Technical Specifications, the Code of Federal Regulations, and the licensee's administrative procedures.

b. Fire Drill

On February 1, 1990 the resident inspector witnessed a fire drill involving a simulated lube oil fire at the HPCI turbine. The drill was announced at 2:08 p.m. and the simulated fire was extinguished at 2:20 p.m. The Fire Brigade competently performed its tasks.

c. Improperly Sized Valve Operators

During a surveillance of the RHR system (Test #0255-4-IA Part 1) conducted on December 28, 1989, the operator mistakenly attempted to close the outboard Torus Discharge valve, MO-2006, prior to closing the throttle valve, MO-2008, as the procedure required. MO-2006 was unable to fully close as required against the discharge flow of the RHR pump. MO-2007, the counterpart to MO-2006 in the other train, was also unable to close against the discharge pressure of the RHR pump. Both of the Rotork operators for these valves had been replaced during the last refueling outage.

The licensee is still reviewing the sizing of the operators and is working closely with Rotork to resolve the issue. The licensee is also reviewing IE Information Notice 89-88, "Recent NRC-Sponsored Testing of Motor-Operated Valves," for applicability to this situation. The licensee intends to replace the valve operators for MO-2006 and MO-2007 following determination of the properly sized operators. This issue is an unresolved item (50-263/90002-01(DRP)) pending determination of why the incorrectly sized operators were ordered and whether the old operators would have actually functioned in accordance with design specifications.

d. Emergency Filtration Train (EFT) System Operability

While performing post-maintenance testing on the EFT system following replacement of a control relay on 2/15/90, the system engineer determined that the regular EFT quarterly surveillance test did not demonstrate the ability of the relay to perform its function. Further investigation and testing revealed that while the relay functioned properly, the logic of the EFT system did not

perform in the manner expected; specifically, low flow situations could be hypothesized that could have permitted enough backflow from the operating fan through the disabled fan to inhibit the system's ability to adequately pressurize the control room.

The licensee took prompt corrective action by installing temporary jumpers in the logic circuit to ensure that the system would operate properly under the hypothesized conditions. A permanent fix is being developed. The licensee intends to test the as-found configuration of the EFT trains to determine whether or not the system could have fulfilled its function. This issue is considered an unresolved item (50-263/90002-02(DRP)) and will be addressed in future inspection reports.

5. Monthly Maintenance Observation (62703)

Station maintenance activities of safety-related systems and components listed below were observed/reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards and in conformance with technical specifications.

The following items were considered during this review: the Limiting Conditions for Operation (LCO) were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and, fire prevention controls were implemented.

Work requests were reviewed to determine status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which may affect system performance.

The following maintenance activities were observed/reviewed:

- WRA 89-00912, Replace Relay 9116BX With Spare From Panel, EFT B Train Flow Switch
- WRA 90-04977, Rebuild #11 EDG-ESW Pump and Place in Stock
- WRA 90-05227, Repair/Replace Relays/Components in V-ERF-12 Control Circuit Affecting Low Flow Circuit, EFT "B" Train
- WRA 90-05230, Install Jumpers in EFT Control Circuitry

The WRAs associated with the EFT system were reviewed in response to problems identified and discussed in Paragraph 3.d.

No violations or deviations were identified.

6. Monthly Surveillance Observation (61726)

The inspectors observed surveillance testing and verified that testing was performed in accordance with adequate procedures, that Limiting Conditions for Operation were met, that removal and restoration of the affected components were accomplished, that test results conformed with technical specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspector reviewed/observed the following test activities:

- Test #0002/0010, Calibration #0019, Reactor High Pressure Scram Instrument Test and Calibration Procedure, Rev. 7, TS 4.1, 3.1.1
- Test #0027, 0421, Calibration #0028-2, 0422-2, Reactor Lo Lo Level ECCS Initiation and Hi Level RCIC, HPCI Turbine Trip Unit Test and Calibration Procedure, Rev. 11, TS 4.2, Table 4.2.1 (Note 10)
- Calibration 0430, Sensor Check 0431, Containment H2/02 Analyzers, TS 3.14

The licensee continues to perform very well in the area of surveillances. The procedures are detailed and the individual responsible for each step (technician or operator) is designated for performance of each step in the procedures. Steps that directly affect TS requirements are so designated. Communications are a major strength as demonstrated by the use of local intercoms at the in-plant instrumentation stations and the use of echo commands when transferring surveillance duties within the procedure.

No violations or deviations were identified.

7. Licensee Event Reports

The inspector reviewed the following Licensee Event Reports (LERs) by means of direct observation, discussions with licensee personnel, and review of records. The review addressed compliance to reporting requirements and; as applicable, immediate corrective actions, and that appropriate actions to prevent recurrence had been accomplished.

(Closed) Licensee Event Report (263/88005): Standby Gas Treatment System Initiation Due to Radiation Detector Failure.

This event involved an isolation of the Reactor Building Ventilation and an initiation of the Standby Gas Treatment System as a result of an upscale spike on the Channel B Reactor Building Vent Wide Range Gas Monitor (WRGM). This spike was caused by the failure of the low range

detector. The licensee replaced the detector to reestablish the operability of the system. This was the only corrective action taken.

This item is closed.

(Closed) Licensee Event Report (263/89004): Simultaneous Loss of Sample Pumps Caused Reactor Building Ventilation Isolation and Standby Gas Treatment Initiation.

While an operator was using the individual keyboards for all four WRGMs to simultaneously obtain log readings, the sample pumps for all four monitors tripped. This caused a Reactor Building Ventilation isolation, a Standby Gas Treatment System initiation and an Offgas Stack isolation.

The licensee has revised their log sheets to specify that operators and chemists should obtain readings from only one of the four WRGMs at a time. The inspector verified that the Operations Daily Log, Part D, Rev. 50 contains a caution note at the top of the data sheet that states that only one WRGM reading should be taken at a time.

This item is closed.

(Closed) Licensee Event Report (263/89005): Auto Isolation of HPCI Steam Line During Surveillance Test Due to Suspected Relay Malfunction.

During the performance of the HPCI System Operability Test, the HPCI Steam Isolation Valves closed upon receiving a Primary Containment Group IV Isolation from an ESF actuation signal. The closure was the result of a HPCI steam line high flow signal. No steam leak indications were noted, nor was there an increase in the release rate. A system walkdown was performed and no leaks were found. Appropriate reviews were conducted, concurrence from plant management was obtained, and HPCI was unisolated. Operability of redundant systems was demonstrated. The HPCI System Operability test was successfully run six times after the event.

The root cause of the event was suspected to be the improper actuation of the HPCI steam line high flow time delay relays. The relays were checked and verified to operate properly immediately after the event. As a precautionary measure, the relays were replaced.

The inspector reviewed and observed the actions taken in regard to this event and believes that the licensee took reasonable and comprehensive action to determine the cause.

This item is closed.

(Closed) Licensee Event Report (263/89011): Excessive Check Valve Leakage Constitutes Potential Degradation of HPCI System.

During cold shutdown a hydrostatic test of feedwater piping revealed excessive leakage past Reactor Water Cleanup (RWCU) return check valve RC-6-1 from the "B" Feedwater line via the HPCI system injection line.

During subsequent plant operations, the line was isolated with all RWCU return flow going to the "A" Feedwater line. RC-6-1 was replaced during the subsequent 1989 refueling outage. The inspector was satisfied with the licensee's corrective actions.

This item is closed.

(Open) Licensee Event Report (263/89017): Trip of "A" Reactor Wide Range Gas Monitor.

The previous write-up of this LER in inspection report 263/89023 noted that this LER appeared to be similar to 263/89-015 reported four days earlier. This was not noted in the submittal for 89-017 and a statement was made that a correction would be required. Further discussions with the system engineer indicated that these two LERs, while related to the firmware for the WRGMs, were not similar in cause or corrective action. No correction is required to LER 263/89-017. Corrective action associated with this LER will be examined by the inspector in the future.

8. Containment Integrated Leak Rate Test Results Evaluation (70323)

a. Review of Test Log

The inspectors performed a review of the test log submitted by the licensee. During this review, the inspectors noted that the containment experienced a high leakage rate once the temperature had stabilized. The licensee log indicated that a test start was not declared until all of the major sources of leakage had been identified and isolated. During conversations with the licensee about the events in the test log, the licensee stated that isolation of the main steam isolation valves (MSIVs) by placing a block in the line and maintaining pressure on the back side of the block had been done without a change to the test procedure and was not controlled by any other procedure. This is considered a violation of 10 CFR 50 Appendix B, Criterion V (50-263/90002-03(DRP)).

The licensee discussed with the inspectors the root cause of why four of the MSIVs experienced excessive leakage during the CILRT, although they had passed both their as-found and as-left Local Leak Rate Tests. The licensee identified crud on the MSIV valve seats due to flushing of the recirculation lines as the most likely source of the leakage. Only one of the four leaking valves required rework following the CILRT. The inspectors had no further concerns in this area.

b. CILRT Data Evaluation

Following isolation of the leaking MSIVs, a 10.5 hour CILRT was performed on October 22, 1989 at 56.6 psia following satisfactory completion of the required temperature stabilization period. Data was collected every 15 minutes. The inspectors independently

evaluated the leak rate data using BN-TOP-1 total time formulas to verify the licensee's calculations of the leak rate and instrument performance. There was good agreement between the inspector's and licensee's results as indicated by the following summary (units are in weight percent per day).

Measurement	Licensee	Inspector
Leak rate measured during CILRT (Lam)	0.295	0.295
Lam at upper 95% confidence level	0.484	0.485

Appendix J acceptance criteria at 95% UCL: $\leq$0.75 La = $\leq$0.9 wt%/day

c. Supplemental Test Data Evaluation

After the satisfactory completion of the CILRT, a known leakage rate of 7.84 scfm, equivalent to 1.182 wt%/day was induced. Data was collected and analyzed by the licensee every 15 minutes. The inspector independently evaluated leak rate calculations using the data submitted by the licensee to verify the licensee's results. After 5.5 hours, the supplemental test was terminated with satisfactory results as indicated by the following summary (units are in wt%/day). The results were stable within the acceptance criteria.

Measurement	Licensee	Inspector
Measured leakage rate, Lc, during supplemental test	1.565	1.561
Induced leakage rate, Lo	1.182	1.182
Lc - (Lo + Lam)	0.088	0.084

Appendix J acceptance criteria -0.300 $\leq$[Lc -(Lo +Lam)] $\leq$0.300

d. CILRT Valve Lineup Penalties

Due to valve configurations which deviated from the ideal penetration valve lineup requirements for the CILRT, the results of LLRTs for such penetrations must be added as a penalty to Lam at the 95% UCL. The following penalties were added using the "minimum pathway leakage" method:

Penetration (System) (Units are in SCFH)	Local Leak Rate Test Value
X-2 (Airlock)	1.850
X-7A & 7B (Main Steam A & B Lines)	7.023
X-12 (Shutdown Cooling)	0.000

Penetration (System) (Units are in SCFH)	Local Leak Rate Test Value
X-13A (Low Pressure Coolant Injection Train B)	0.000
X-13B (Low Pressure Coolant Injection Train A)	0.000
X-14 (Reactor Water Cleanup Inlet)	0.101
X-16A (Core Spray Loop B)	0.309
X-16B (Core Spray Loop A)	0.000
X-17 (Residual Heat Removal Head Spray)	0.000
X-18 (Floor Drain Sump)	0.533
X-19 (Equipment Drain Sump)	2.310
X-23 (Reactor Building Closed Cooling Water (RBCCW) to Drywell)	0.000
X-24 (RBCCW from Drywell)	1.106
X-26 (Drywell Purge)	0.000
Penetration (System) (Units are in SCFH)	**Local Leak Rate Test Value**
X-27 (Primary Containment Atmospheric Monitoring)	0.000
X-41 (Reactor Water Sample)	0.000
Combustible Gas Control	0.000
Total Type C Leakage Penalty:	13.232 (or 0.033 wt%/day)

After taking these local penalties into account, the final upper 95% confidence value for containment leakage was equal to 0.518 wt%/day, which is within the acceptable value of $\leq$0.900 wt%/day.

e. As-Found Condition Containment

The as-found condition is the condition of the containment at the beginning of the outage prior to any repairs or adjustments to the containment boundary. The inspector reviewed the licensee's summary of the containment penetration LLRTs (Type B and C) performed prior to the CILRT in order to determine the amount of leakage rate improvement due to repairs or adjustments. Based on the results reviewed, the inspector determined that the amount of the leakage improvement prior to the CILRT equalled 40.052 scfh, or the equivalent of 0.101 wt%/day. Based on this, the final containment leakage rate, at the 95% UCL, was 0.619.

The containment was considered to have passed the as-found periodic CILRT.

9. Status of TMI Items (25565) (For previous status, see Inspection Report No. 50-263/86-007)

(Open) I.D.2.2: Plant Safety Parameter Display Console (SPDS) Installation. The SPDS system was installed during the Cycle 12 refueling outage. This item will be closed during the Emergency Response Facility (ERF) appraisal.

(Open) I.D.2.3: SPDS Full Implementation. The licensee commitment was to have SPDS fully implemented six months after the startup following Cycle 12. The SPDS is currently fully operational. This item will also be closed during the ERF appraisal.

(Closed) II.K.3.28: Qualifications for Accumulators. Physical work on the modifications involved in this item has been completed. Final Administrative closeout of the modification packages is to be completed by March 1990.

(Closed) II.F.2.4: Instrumentation for the Detection of Inadequate Core Cooling. (This item was previously identified as II.F.2.3.B, but was renumbered between 1986 and 1989). Modifications were completed during the Cycle 12 refueling outage in 1987. All modification requirements have been completed, and the Technical Specifications have been appropriately amended. This item is closed.

(Closed) II.K.3.18.C: ADS Actuation Logic Modification. All work has been completed on this modification including drawing changes. This item is closed.

10. Regional Request for Information

The Division of Reactor Projects Branch 2 Chief requested information related to Perry Unit 1 Reportable Event No. 17201, regarding Control Rod Scram Failures. The problem regarded the use of urethane seating material in the scram pilot valves in lieu of the viton specified in the environmental qualification documentation.

The inspector discussed this reportable event with the cognizant system engineer and determined that the licensee was aware of this problem, had investigated and determined that the problem did not exist at the Monticello plant.

11. Exit Interview

The inspectors met with the licensee representatives denoted in Paragraph 1 on February 22, 1990. The inspectors discussed the purpose of the inspection and the findings. A separate exit interview was held with the licensee on December 14, 1989, to discuss the results of the EOP Special Inspection Team closeout inspection.

The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any documents/processes as proprietary.