U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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Facility:	Indian Point 3 Nuclear Power Plant
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EXECUTIVE SUMMARY

Indian Point 3 Nuclear Power Plant
NRC Inspection Report No. 50-286/97-03

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a seven-week period of resident inspection.

Operations

The operator response to the overpower delta temperature runback was good. The decision by the operators to manually trip the reactor was consistent with safe and conservative plant operation. All safety related equipment responded as required to the runback and trip. The operators implemented the emergency operating procedures in a professional manner with good three-point communications and clear directions from the control room supervisor. Operator conduct during the subsequent plant shutdown was also very good. (Sections O1.2 and O1.3)

The work planning and work control systems were not effectively implemented during the performance of fuel storage building (FSB) roof repairs. The work planning process did not identify the potential adverse effects of the repair material on plant equipment and the work control center did not pursue whether FSB roof repairs could be done in parallel with operating the FSB ventilation system. An incorrect interpretation by the operators resulted in two technical specification required tests not being performed prior to declaring the FSB ventilation system operable. This was a violation of NRC requirements. (Section O1.4)

Appropriate corrective actions were not taken to resolve operation of the residual heat removal system in a manner that was inconsistent with the Final Safety Analysis Report (FSAR). Operation in this manner continued for four days without adequate resolution. This was a violation of NRC requirements (Section O3.1)

Preparations to support refueling outage 9 (RO-9) were well performed by the entire plant staff and provided the necessary framework for the conduct of a safe outage. A well defined outage management organization was established by the licensee prior to commencing the outage. Extensive training and certification processes were developed and implemented for both licensee and contractor staff to ensure that they were qualified to perform outage activities. The outage schedule and daily risk assessment were effective in identifying schedule conflicts and in developing appropriate contingency actions. Items excluded from the scope were reviewed and an adequate basis existed for their exclusion. A good effort was undertaken to revise operating and refueling procedures prior to the outage. (Sections O6.1, O6.2, O6.3, O6.4, and O6.5)

Operations department management's awareness and response to human performance issues was appropriate. The overall operations error rate has decreased, particularly for licensed operators and support staff. However, this decrease was not similarly achieved for non-licensed operators. Also, a recent trend indicated that the licensee was identifying more non-licensed operator errors, which required formalized investigations. Two recent

errors were the overpressurization of the letdown system and the overpressurization of a holding tank in the condensate polisher facility. (Section O4.1)

Maintenance

Mixed performance was noted during the conduct of maintenance and surveillance activities. Generally good procedure adherence and controls were noted for several of these activities, most notably by maintenance personnel during the 33 charging pump discharge check valve replacement and by instrumentation and controls (I&C) personnel during a pressurizer pressure channel surveillance test. (Sections M1.8 and M1.11)

However, several examples of poor oversight and control of pre-outage work activities were noted. The decision and documentation for planned technical specification (TS) limiting condition of operation entries for the 31 and 33 emergency diesel generators (EDGs) were weak in that the safety benefit of the work was not well understood. The control of lagging removal on the 32 auxiliary boiler feedwater pump was weak in that informal guidance on lagging removal was not effectively communicated to plant staff. Two instances were identified where scaffolding was improperly erected around safety related equipment. Two instances were identified where temporary equipment was staged in the 31 and 33 EDG cubicles that could have adversely affected safety related equipment. The work package for excavation around buried service water (SW) piping did not contain adequate guidance or limitations to ensure that the SW lines would maintain their seismic qualification. The erection of scaffolding was also a violation of NRC requirements. (Sections M1.2, M1.3, M1.4, M1.5, and M1.6)

Poor foreign material exclusion controls were noted during maintenance on the 31 instrument air compressor in that openings were not properly covered during a work break when the work area was left unattended. This was a violation of NRC requirements. (Section M1.7)

The licensee failed to include the close function of residual heat removal suction valves MOV-730 and MOV-731 in the inservice test program. The cause of this was the inappropriate determination that the closing function did not mitigate the consequence of an accident. This was a violation of NRC requirements. (Section M1.10)

Engineering

Adequate procedures were not established and implemented to control revisions to fuel handling transfer forms. A revision to delete steps from a transfer form was not processed in accordance with procedure requirements. Also, direction for changing the sequence of the transfer forms was not consistent between refueling and reactor engineering procedures. This was a violation of NRC requirements. (Section E3.1)

Two design deficiencies were previously identified by the licensee that resulted in plant operation outside of its design basis. The first issue involved design deficiencies with the

EDG ventilation system power supplies and the failure to enter TS action statements during maintenance on the fans. The second issue involved use of the spare 35 battery charger that placed the plant outside its design basis. These apparent violations of NRC requirements involved old design issues in which licensee identification was a result of a good questioning attitude or a comprehensive technical specification upgrade effort. The corrective actions were comprehensive to prevent recurrence. These design issues were not likely to be identified by routine licensee efforts such as normal surveillance or quality assurance activities. As a result of the good efforts to identify and correct these subtle violations, these violations were not cited in accordance with Section VII.B.3 of the NRC Enforcement Policy. (Sections E8.1 and E8.2)

Plant Support

Routine inspections of radiological controls and security were performed during this period. Radiological areas were properly barricaded, posted and personnel were observed complying with radiological work permit requirements. Security stations were properly manned, and protected and vital area barriers were maintained.

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Report Details

Summary of Plant Status

The unit began the inspection period at full power, and remained at full power until a reactor power coastdown commenced due to the end of the operating cycle. On May 14, 1997, with the plant at 91% reactor power, the unit experienced a main turbine generator runback caused by the reactor coolant loop 2 overpower delta temperature circuitry. The operators manually tripped the reactor after the runback caused reactor power to decrease to approximately 70%. The plant was placed in the cold shutdown condition and refueling outage 9 was commenced on May 15. The plant remained in the cold shutdown condition at the end of this inspection period.

I. OPERATIONS

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant operations. Overall, the licensee conducted plant operations well. The inspector observed good performance in shift turnovers, communications and procedure adherence. Significant events and noteworthy observations are discussed in the following sections.

On April 16, 1997, the inspector reviewed selected control room problem identification deficiencies (PIDs) to verify the status of work planning, and if they were either identified as a control room deficiency or an operator work around. The inspector concluded that all PIDs reviewed were appropriately tracked as either control room deficiencies or operator workarounds. There were a total of sixty-three control room deficiencies of which 8% were identified before 1995.

O1.2 Manual Reactor Trip

a. Inspection Scope (93702)

On May 14, 1997, the inspectors observed the operators response during the turbine runback and subsequent manual reactor trip. During the event, the inspector also conducted walkdowns to assess the operation of safety-related equipment.

b. Observations and Findings

On May 14, 1997, at 5:21 p.m., the operators conservatively tripped the reactor based on a turbine runback that was unexplained and unrecoverable given the end-of-life condition of the reactor core. The turbine runback signal was overpower delta temperature on the No. 2 reactor coolant loop bistable. The turbine runback lasted approximately 42 seconds from which reactor power decreased from approximately 91% to 70%. Instrumentation monitoring reactor coolant parameters

did not indicate a need for the runback. The licensee is investigating the cause of the turbine runback.

Based on system walkdowns, control room observations and review of post trip data, the inspectors concluded that all safety systems responded as required during the manual reactor trip. At the time of the trip, the 31 emergency diesel generator (EDG) was out of service for preventive maintenance. Licensee expedited actions and restored the generator to an available status approximately 40 minutes after the reactor trip. The 31 EDG was subsequently tested and restored to an operable status at 1:45 a.m. on May 15.

The operators implemented the emergency operating procedures in a professional manner with good three-point communications and clear directions from the control room supervisor. The inspector observed two anomalous conditions during the transient that the operators had not identified during the post-trip critique. The inspector observed that the reactor operator deenergized the backup pressurizer heaters in response to reactor coolant pressure higher than normal (post-trip) at 2,280 psig. Although this was an appropriate operator action, the heaters are designed to cycle on and off to maintain pressure within a specific range. Additionally, a fire alarm in the auxiliary boiler feed pump room was received in the control room. Investigation by a non-licensed operator revealed no indication of fire in the room, but there was excessive steam blowdown from the steam traps associated with the 32 auxiliary boiler feed pump. The lack of identification of these two anomalous conditions indicated a need for the operators to improve their threshold for questioning problems. The inspector discussed this observation with the operations manager. The preliminary post transient review group report on May 17, 1997, identified seventeen areas of concern or issues that included the two above deficiencies. However, at the end of this inspection period, the licensee had not yet completed the equipment causal analysis for the runback. The cause of the over power delta temperature turbine runback is considered an inspector followup item.

c. Conclusion

All safety systems responded as required during the manual reactor trip. The operator decision to trip the reactor was conservative given no direct confirmation of the turbine runback and the degree of power reduction from the runback. The operators implemented the emergency operating procedures in a professional manner with good three point communications and clear directions from the control room supervisor. The failure of the operators to identify two anomalous conditions during the post-trip critique indicated a need to improve their threshold for identifying problems. Licensee determination of the cause of the turbine runback is an inspector followup item **(IFI 97-03-05)**.

O1.3 Plant Cooldown and Depressurization

a. Inspection Scope (71707)

The inspectors reviewed various portions of plant shutdown and cooldown performed by the licensee in preparation for the refueling outage.

b. Observations and Findings

The inspectors observed portions of the plant cooldown, placing the overpressure protection system and residual heat removal system in service, and collapsing the pressurizer bubble. Operator conduct during these evolutions was very good. The operators conducted activities in a safe and conservative manner with good command and control by shift management noted. Procedure adherence and communications were also very good.

The quality of the operating procedures used to place the plant in cold shutdown was good with clear and concise direction provided. Many of these procedures had been recently upgraded prior to the refueling outage, and were performed with minimal procedure changes required.

The inspectors walked down and verified eight protective tagouts (PTOs) which had been established to maintain plant conditions and allow the safe performance of various work activities. The inspectors concluded that these PTOs provided adequate isolation for the activities involved.

c. Conclusions

Operator conduct during plant shutdown and while establishing required conditions for the refueling outage was very good. Good management oversight, procedure adherence, and communications were noted during all aspects of these activities. Procedure quality was also good with only minor procedure changes required to perform the shutdown.

O1.4 Fuel Storage Building Ventilation

a. Inspection Scope (71707, 61726)

Repairs to the fuel storage building (FSB) roof placed the FSB ventilation system in a degraded condition. The inspectors reviewed the causes of this event and actions taken by the licensee in response.

b. Observations and Findings

On April 16, 1997, repairs to the FSB roof were authorized per work request (WR) 97-00013-03 to address water in-leakage. The scope of work entailed using roofing tar to seal leaks around the two FSB ventilation inlet ducts. Subsequent to

work authorization and while the repairs were in progress, the FSB ventilation system was operated to support new fuel movement.

On the morning of April 17, the FSB ventilation system was again started to support new fuel movement. Soon after, the control room was notified of excessive fumes in the FSB, and the ventilation system was secured. Operations personnel consulted with performance engineering, and determined that the roofing repair material contained benzene, which can have a adverse effect on charcoal adsorption efficiency. Since the ventilation system had been in service with flow through the charcoal filters, operations declared the FSB ventilation inoperable.

Testing was performed by the licensee in accordance with procedure 3PT-R32A, Fuel Storage Building Filtration System, to verify the integrity of the charcoal system. Two tests were performed to obtain a charcoal sample to verify methyl iodine removal efficiency and to measure the halogenated hydrocarbon removal efficiency of the charcoal filters. The results of these two test were satisfactory and the operators declared the FSB ventilation system operable on April 19, 1997.

The NRC reviewed the cause of the ventilation system inoperability, and actions taken by the licensee in response to the event. The inspectors concluded that the work planning and work control systems were not effectively implemented during the performance of FSB roof repairs. Neither the maintenance supervisor or the field support supervisor (FSS) were aware that the roof repair material contained Benzene. Also, the control room operators were not aware of the roof repairs in progress prior to operating the FSB ventilation system. The inspectors concluded that better communications between the work control center and the control room may have questioned the potential effect of the roof repair material and prevented the inoperability of the ventilation system. The licensee initiated a deviation event report and was developing corrective actions to address these issues.

The NRC also reviewed the testing completed by the licensee to restore system operability and determined that all technical specification (TS) required testing had not been completed. TS 4.5.A.6.c states in part that any time chemical releases could alter the integrity of the filters, that four conditions shall be demonstrated before the system can be considered operable. The licensee only demonstrated two of the four conditions prior to declaring the system operable on April 19. The other two conditions not demonstrated involved particulate testing of the HEPA filters and a visual inspection of the filters. The licensee had determined that these other two conditions did not need to be verified since the Benzene fumes would only affect the charcoal filter integrity and would not have affected the functions verified by these tests.

On April 25, 1997, the NRC informed licensee management that all four tests required by TS 4.5.A.6.c had not been completed as required prior to declaring the system operable. The licensee declared the FSB ventilation system inoperable effective April 17, reperformed all four tests per procedure 3PT-R32A satisfactorily, and declared the system operable on April 27, 1997. The licensee initiated DER 97-0832 to investigate why the technical specifications for FSB operability were not

complied with. The licensee issued licensee event report (LER) 97-004 on May 27, 1997 to report this event.

c. Conclusions

The work planning and work control systems were not effectively implemented during the performance of FSB roof repairs. The work planning process did not identify that the roof repair material contained Benzene, which could have an adverse effect on charcoal adsorption efficiency. The work control center did not question whether FSB roof repairs could be done in parallel with operating the FSB ventilation system, and the control room was not aware of the FSB roof repairs in progress. Better communications between the work control center and the control room may have questioned the potential effect of the roof repair material on the ventilation system and prevented the inoperability of the system. Operations was pursuing corrective actions to address these issues. Similar weaknesses in the work planning and work control processes were observed during lagging removal and excavation around service water piping, as documented in sections M1.3 and M1.6 of this report.

An incorrect interpretation of TS 4.5.A.6.c by the control room operators resulted in two technical specification required tests not being performed prior to declaring the FSB ventilation system operable. This was a violation of NRC requirements. **(VIO 97-03-01)**

O3 Operations Procedures and Documentation

O3.1 Residual Heat Removal System Operation

a. Inspection Scope (71707)

While reviewing operating procedures, the inspectors observed a discrepancy between operation of the residual heat removal (RHR) system suction valves when in cold shutdown and the Final Safety Analysis Report (FSAR). The inspector reviewed the licensee's resolution of this discrepancy.

b. Observations and Findings

During a review of plant operating procedures to support the refueling outage, the inspectors noted a discrepancy with the FSAR. Plant operating procedure (POP) 4.1, revision 11, Operation At Cold Shutdown, directed that RHR suction valves AC-MOV-730 and AC-MOV-731 be de-energized open when the reactor coolant system (RCS) was depressurized and vented. Operation of the plant in this configuration was not consistent with FSAR section 6.2.3, which states that these valves are automatically closed when RCS pressure is above a designated setpoint. The licensee had previously identified this inconsistency and initiated DER 97-292 on February 7, 1997, to document it. At that time, the plant was in a forced outage with the RCS depressurized and vented and the RHR suction valves deenergized open. Corrective actions taken by the licensee included assigning an

action commitment tracking system (ACTS) item to engineering to evaluate the appropriate condition of the valves. Further, the licensee decided to leave the valves deenergized based on work in progress at the time and the risk assessment done for the scheduled work. The valves were not re-energized until February 10, when the reactor coolant system was repressurized.

The inspectors reviewed this event with the licensee and noted that a nuclear safety evaluation (NSE) was currently being prepared by system engineering to evaluate this change in operation per 10 CFR 50.59. This NSE, which was completed on May 15, 1997, supported operations in this manner. However, the inspectors concluded that appropriate corrective actions to perform a written operability determination were not taken in accordance with station procedures when the problem was first identified on February 7.

In response to the initiation of DER 97-292 on February 7, the shift manager determined that the RHR system was in the correct alignment and a written operability determination was not required. However, a design feature of the suction valves to automatically isolate the RHR system from the reactor coolant system was defeated. Further, the DER stated that the RHR system was not being operated in accordance with the FSAR, and an evaluation per 10 CFR 50.59 could not be located. Therefore the RHR system was in a non-conforming condition, which required further evaluation to resolve and the shift manager conclusion that a written operability determination was not required was inappropriate. AP-8 Deviation & Event Reporting and Operability Determination Procedure, Revision 37, section 4.18 requires that an operability determination shall be initiated for degraded and non-conforming conditions for which the operability status of the system is indeterminate. AP-8, attachment 6, section 4.3.4 further requires that an initial evaluation based on engineering judgement should be documented within 24 hours with the final engineering assessment completed within 30 days. Contrary to these requirements, the RHR system continued to be operated with the suction valves deenergized until February 10, 1997, without documenting an operability determination.

c. Conclusions

Appropriate corrective actions were not taken when it was identified that the RHR suction valves were being operated with the automatic isolation design feature defeated which was inconsistent with the FSAR. Operations incorrectly concluded that an operability determination was not required, although this mode of operation with a design feature defeated had not been evaluated. As required by AP-8, an written operability determination should have been performed to document engineering evaluations to justify continued operation in this manner. The failure to take appropriate corrective action to perform a written operability determination was a violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions. **(VIO 97-03-02)**

O4 Operator Knowledge and Performance

O4.1 Human Performance Review

a. Inspection Scope (71707)

The inspector evaluated operations department human performance. The scope of this review considered operator errors from January 1996 through April 1997. The inspection consisted of reviews of the licensee's deviation event report (DER) system, operation's self-assessment reports, operational review group's (ORG) tracking and trending reports, quality assurance assessment of operator performance, and attendance at a performance enhancement review committee (PERC). The purpose of the evaluation was to assess the adequacy of licensee actions in regard to operations department human performance.

b. Observations and Findings

The process for classifying human performance events, monitoring program effectiveness and evaluating events is identified in administrative procedure (AP)-37.5, IP3 Performance Enhancement Program. Human performance events are documented and classified for significance using AP-8.2, Deviation Event Analysis.

The inspector evaluated the DERs on human performance and focused on apparent causes and proposed corrective actions. The inspector assessment of errors from non-licensed operators concluded that errors were generally attributed to inter-crew communication deficiencies, and procedural adherence. The trend of errors has remained constant during the last sixteen months with an error rate of 0.875 DERs per month. However, the significance of the errors in these DERs has increased in the last six months with more level A and B DERs than level C.

The recent trend (last six months) for the control room operator error rate has shown a significant decrease (approximately 30%). The current error rate is approximately 1.33 DERs per month. Generally, a good relationship existed between causal analysis and corrective actions for individual DERs. Exceptions to this include DER 96-457 in which poor procedural quality was discussed with the individual initiating the error; DER 96-312 in which no apparent cause was stated; DER 96-791 in which inter-crew communications were not evaluated; and DER 96-895 in which the failure to use a procedure was not evaluated. In general, the inspector noted an improvement in adhering to procedures as indicated by the lack of recurrent issues identified in the licensee's DER process.

The inspector's assessment of operations support personnel human performance also noted improvement in the error rate. The error rate in the last six months in comparison to the last sixteen months showed a decrease of approximately 22%. Improvements were noted based on the lack of recurrence in issues concerning nuclear safety evaluation screen quality for operations procedures, and performance of the field support supervisors (FSSs). The inspector identified two DERs whereas

the corrective actions did not agree with the apparent causes in DER 96-0481 and DER 96-2077 concerning protective tagout discrepancies.

The operations department management's awareness and response to human performance issues was appropriate. In late 1996 and early 1997, operations management provided results of human performance reviews to the individual crews. The intent was to provide for crew discussions to evaluate their performance and recommend methods to improve performance. Accountability for operator performance was one of the corrective actions, which one crew was tasked to address an adverse trend in the error rate through most of 1996. However, recent events indicate corrective actions thus far have not been fully effective. The inspector noted that two recent human performance events identified by the licensee in May 1997 concerned improper tag out of the non-safety related caustic pumps and a work scheduling error on removal of auxiliary boiler feed pump fan for maintenance.

The ORG provided various indicators on human performance to licensee management. The tracking and trending of error rates are provided in the weekly performance indicator data and the monthly assessment reports. Additionally, ORG reviewed the acceptability of apparent causes and corrective actions and contributed to the PERC meetings. The inspector evaluated the monthly assessment reports to determine the quality of assessments of human performance, and what recommendations were provided to licensee management. Generally, the monthly assessment reports tracked error rates for the station and individual departments and provided a trend over the last year. In February 1996, ORG initiated DER 96-0277 to highlight an adverse trend in station human performance rate. In February 1997, the ORG noted that the station error rate increased and prepared weekly tailgate meetings to stress self-verification, and, in March 1997, a plant "stand-down" was initiated for protective tagging errors and human performance events. Past licensee actions taken from the monthly ORG assessment reports were appropriate.

The inspector attended a PERC meeting on April 18, 1997, that discussed a human performance error by a non-licensed operator. The error involved the misalignment of the ammonium hydroxide tank in the condensate polisher facility and resulted in an over pressure condition to the holding tank. The apparent cause was less than adequate self-checking by the operator. The PERC discussion of the event probed the adequacy of the causal investigation and the development of contributing factors. The PERC requested a trend DER on newly qualified non-licensed operators since another event occurred in early 1997 involving the overpressurization of the letdown system. That error was documented in NRC inspection report 50-286/ 97-01. The inspector concluded that for the recent event, corrective action to have the non-licensed operator provide a "lessons-learned" discussion to the crew was appropriate.

c. Conclusions

The operations department management's awareness and response to human performance issues was appropriate. The overall operations error rate, particularly for licensed operators and operations support staff, has decreased. However, a similar decrease for the non-licensed operators was not achieved. Also, a recent trend indicated that the licensee was identifying more non-licensed operator errors, that required formalized investigations. Two recent errors were the overpressurization of the letdown system and the overpressurization of a holding tank in the condensate polisher facility. During a PERC meeting, the licensee thoroughly reviewed the causal investigation and development of contributing factors. Also, the PERC requested a trend DER on newly qualified non-licensed operator errors that were based on these two recent events.

O6 Operations Organization and Administration

O6.1 Refueling Outage Management Oversight

a. Inspection Scope (60705)

The inspectors reviewed the outage management organization developed for the upcoming refueling outage and assessed member roles and responsibilities.

b. Observations and Findings

The outage management organization and functions are described in AP-9.5, Outage Management. The procedure thoroughly described the outage management organization and clearly defined the roles and responsibilities of the various functions in the organization.

The inspectors reviewed roles and responsibilities with various members of the outage team, including the Outage Manager, three Shift Outage Managers, an Outage Coordinator, a Project Coordinator, Operations and I&C management. All personnel clearly understood their position in the outage management organization and their associated duties. The division of responsibility for maintaining safe plant configuration and coordinating outage work was clearly understood between operations and outage management team members.

The inspectors reviewed the operations department plans for shift manning to support the outage. The normal six shift rotation will be reconfigured into two 12 hour shifts during the outage. This will allow a shift manager and a senior reactor operator to man both the control room and the work control center. This arrangement will provide additional operations management oversight in the work control center and relieve the control room of any outage work processing. Operations management personnel will also provide extended 24 hour oversight for significant plant evolutions such as certain mode changes and reactor startup.

A significant portion of the outage work, such as refueling and steam generator inspections, will be performed by Westinghouse contractors. The inspectors reviewed the contractor management team organization with the Westinghouse manager and with NYPA outage team members. The oversight of contractor activities, and the relationships and responsibilities between contractor and NYPA management were understood by both parties.

The outage team was put in place on May 1, 1997, at which time the majority of the team members were relieved of their normal duties and started reporting to the outage manager. The outage management team implemented shift work rotation on May 13. The inspectors concluded that the outage team was established and implemented in adequate time to support the outage.

Several efforts were undertaken by outage management to communicate the outage management oversight process to the plant staff. On May 1, 1997, the outage manager held tailgate meetings with several departments to review how the outage would be conducted. On May 8, outage management held a team building session with the outage team to review among other things staff roles and responsibilities during the outage. On May 14, station wide all-hands meetings were held by plant and outage management to review the outage and management expectations. The inspectors observed portions of these activities and noted that they were all good initiatives to ensure that plant staff understood the outage organization.

The inspectors noted that various outage scheduling goals had not been met by the licensee. The licensee established outage milestones with revision 3 to AP-9.5 on February 10, 1997. Examples of various goals not met included failure to have department head approval of the outage schedule, outage modification preparation and approval, completion of procedure changes, schedule risk assessments, and protective tagging orders completed for work requests. The licensee attributed the failure to meet the outage scheduling goals due to late initial planning and resources commitments.

The licensee also did not implement a self-assessment audit within 3 months of the scheduled outage as stated in AP-9.5. This occurred since the revision to AP-9.5 which required the self-assessment was not implemented until February 10, 1997 with an initial outage start date of April 1997. The self-assessment audit of outage planning was proposed for planning the next refueling outage (outage 10) in 1999.

c. Conclusions

A well defined outage management organization was established by the licensee prior to commencing the RO-9 refueling outage. The structure of the organization and the roles and responsibilities of the management team members were well described in station administrative procedures. Licensee team members were aware of their roles and responsibilities within the organization and their relationships with operations and contractor management personnel. The scope of the outage and the outage management organization were well communicated to plant staff through team building sessions and several departmental and station wide tailgate sessions.

Several milestones in preparing for the outage were not meet as outlined in station procedures due to a late start in outage planning and competing resource constraints.

O6.2 Refueling Outage Personnel Training and Qualification

a. Inspection Scope (60705)

The inspectors reviewed licensee efforts to ensure that both licensee and contractor staff were adequately trained and qualified to support the upcoming refueling outage.

b. Observations and Findings

The inspectors reviewed the operator training developed for the outage and concluded that an in-depth and thorough training course had been developed. Substantial training covering operating and refueling procedures and technical specifications was included in the licensed operator requalification training cycle sessions. The licensee training department had developed good lesson plans, which were well presented in classroom and simulator training sessions. Good supplemental training for refueling senior reactor operators (RSROs) was also developed and documented through the use of a qualification card. This training included attendance at the 3 day Westinghouse course, reviews of industry experience during refueling activities, and training on recent modifications to the fuel handling systems.

The inspectors reviewed the instrumentation and controls (I&C) department use of contractors for the outage. I&C developed a good department procedure to define a process for using contractors for staff augmentation. The lesson plans, examinations, qualification cards, and qualification matrices developed to train and certify contractors resulted in a thorough and challenging training process.

Administrative procedure (AP)-60, Control of Vendor/Contractor Activities, describes the licensee process for ensuring that contractors are qualified and appropriately trained to perform job specific activities. The inspectors reviewed AP-60 and noted that it provided for a good process to review contractor qualifications and document training given. This process was well implemented by the licensee for steam generator eddy current testing (ECT) contractor personnel.

The inspectors reviewed the qualification process used by the licensee to ensure that contractors were trained and certified to perform steam generator eddy current testing. AP-49, Inservice Inspection Program, requires that the quality assurance (QA) department review all personnel and equipment certifications. QA reviewed the contractor eddy current qualification program per procedure QAP 9.3-I, Administrative Controls for Non-Destructive Examination Processes, to ensure that contractor certification requirements were consistent with the ASME section XI requirements committed to by the licensee. The inspectors reviewed the education, training, and experience of several contractor ECT personnel and verified that they

were certified to current licensee requirements. The inspectors concluded that a thorough process had been developed by the licensee to verify contractor non-destructive examination qualifications.

c. Conclusions

Extensive training and certification processes were developed and implemented by the licensee to ensure that licensee and contractor staff were qualified to perform outage activities. Licensed operator training effectively reviewed shutdown and refueling procedures and technical specification requirements both in the classroom and in the simulator. Good processes were demonstrated by I&C and QA to train and verify that contractor personnel would be qualified to perform outage work activities.

O6.3 Refueling Outage Risk Assessment

a. Inspection Scope (60705)

The inspection consisted of reviewing administrative procedure (AP)-9.2, Outage Risk Assessment, discussions and observations of the risk assessment team, evaluation of the daily risk assessment planned for the upcoming refueling outage, and attendance of operator re-qualification training session on outage risk assessment.

b. Observations and Findings

The inspector reviewed AP-9.2, attachment B, Daily Shutdown Risk Assessment, and focused on the level of detail to satisfy safety functions. The inspector noted that the daily shutdown risk assessment provided weak guidance with regard to system alignments for boration flowpaths, conditions that credit a steam generator available for decay heat removal, system alignments for "normal" spent fuel pool cooling, and sources of make-up to the reactor coolant system. However, the licensee was aware of these weaknesses and was in the process of revising the checklist to provide additional guidance and details, primarily to ensure consistency of implementation between shift managers. The update to the checklist was in progress at the end of the inspection period, with the "draft" checklist used during the operator re-qualification training on May 9, 1997. The inspectors concluded that updating the checklist was a good initiative.

The licensee goal to complete the refueling outage risk assessment two months prior to the outage was not achieved. The goal is documented in AP 9.5. The licensee's risk assessment team was formed during the week of April 28, 1997 using the outage schedule completed on April 16, 1997. The primary reason for the late start on the outage schedule risk assessment was due to delays in the development of the outage work scope.

The inspector observed various working-level meetings of the risk assessment team. The team was composed of four experienced persons from the operations support

group, operator training, and independent safety evaluation group (ISEG). The inspector observations concluded that the team performed a thorough and complete review. This observation was based upon the team's review of all work requests for selected safety systems, involvement with project team discussions (such as service water pipe replacements), review of applicable procedures, and use of plant drawings to validate system alignments and configurations.

The inspector independently verified various maintenance and modification work activities planned on the reactor coolant system, residual heat removal system, and the emergency diesel generators and noted appropriate conclusions for the overall safety function risk assessment. The inspector also independently verified outage maintenance activities at various time intervals during reactor coolant system draindown with high decay heat loads and determined that the licensee's risk assessments were thorough.

The risk assessment team appropriately identified various risk significant schedule conflicts, the need for additional procedural guidance, and the need to establish contingency actions during maintenance activities. Examples included the lack of emergency power availability during reactor system draindown, contingency actions to restore the 31 residual heat removal pump during reactor cavity flood-up, and operations procedure changes to reflect the use of the essential service water header. The licensee was appropriately assigning the recommendations from the review into the action commitment tracking system (ACTS).

The inspector observed the risk assessment team verification of proposed schedule changes involving chemical and volume control system (CVCS) outage work. The risk assessment team had recommended that the maintenance window be relocated outside the core alteration period to improve the reactivity safety function. This change maintained primary and backup preservation of the safety function. The schedule change review included work request start and finish times.

On May 14, 1997 the inspector observed the risk assessment team present their analyses of the outage schedule to the senior outage management team as required by AP-9.2 steps 3.2.3.9 and 3.2.3.10. The purpose of the senior outage management team is to ensure that contingency plans adequately address activities designated as a degraded safety function. The licensee's management team adopted all recommendations from the risk assessment team. The management team recommended methods to make the contingency plans visible to operators and outage supervisors.

The inspector observed operator classroom training on the risk assessment process. The training was appropriate in that it familiarized operators with AP 9.2, discussed the activities of the risk assessment team, and discussed changes to procedures and system configurations that resulted from the risk assessment team's efforts.

c. Conclusions

The risk assessment team appropriately identified various risk significant schedule conflicts, the need for additional procedural guidance, and the need to establish contingency actions during maintenance activities. Operator classroom training on the risk assessment process appropriately familiarized operators with changes in procedures and off-normal system alignments.

O6.4 Outage Scope Control Committee Activities

a. Inspection Scope (60705)

The inspection consisted of evaluation of procedural implementation of AP-9.5, Outage Management, observations of various scope control meetings, discussions with members of the scope control committee, and a selected review of either modifications or maintenance deferred from the upcoming refueling outage.

b. Observations and Findings

The licensee's intent of a scope control committee was to evaluate outage maintenance activities for consideration of deferral or additions to a developed outage schedule. The responsibility of the scope control committee is to verify that the outage activity meets various criteria as described in attachment 2 to AP-9.5. The criteria was developed from industry guidelines.

Inspector review of the procedural implementation of AP 9.5 section 4.6 for expectations on outage scope control, and observations of various scope control meetings identified minor deficiencies. The deficiencies included not identifying the General Manager Operations as a member of the scope control committee, and during the meeting it was not apparent that members voted on either acceptance or rejection of a outage maintenance activity. The inspector observations were discussed with the Outage Manager during the inspection period for resolution.

The inspector evaluated outage maintenance activities considered in the scope control committee from December 1996 through April 1997. Overall, approximately 30% of those maintenance items considered for the scope control committee had been deferred from the outage. The inspector noted a recent trend of increasing the percentage of deferred maintenance activities to approximately 45% since March 18, 1997. Of the maintenance activities deferred, 76% were postponed until the next forced outage or refueling outage, while the rest were scheduled within the twelve-week plant operations maintenance schedule. The evaluation of the outage scope committee activities and decisions will be reviewed during the outage. **(IFI 97-03-06)**

Based upon a random review of those items deferred from the current outage, the inspector concluded adequate bases existed for the deferrals. The inspector selected eleven equipment modifications and corrective maintenance activities to evaluate the basis for removal from the refueling outage scope. The basis for

removal varied, but in general it relied upon on current programs, processes, and equipment performance. An example of a deferred modification was the replacement of the boric acid pumps. This modification was a proposed upgrade to the pump based upon Indian Point Unit 2 experience and to address recurrent maintenance work on seal replacements. The justification to remove the modification upgrade relied on a nine-month preventive maintenance task to replace the pumps with like-in-kind. The review indicated a decision to defer enhancements to the facility and equipment; however, the inspector identified that there were no outstanding operability issues, timeliness of corrective actions, or failures to adhere to previous NRC commitments involved in these deferrals.

c. Conclusions

Based upon a random review of maintenance activities deferred from the current outage, the inspector concluded adequate basis existed, since they did not include outstanding operability issues, corrective action timeliness or failures to adhere to previous NRC commitments.

O6.5 Refueling Outage Procedure Quality

a. Inspection Scope (60705)

Prior to the start of the refueling outage, the licensee revised associated plant operating procedures and refueling procedures in an effort to improve the procedure quality. The inspectors assessed the scope and quality of the revised procedures. The inspectors also reviewed the process for reviewing and approving contractor provided procedures for use during the outage.

b. Observations and Findings

The licensee developed administrative procedure AP-3.3, Review and Acceptance of Vendor-Written Procedures, prior to the outage to describe the process for approving vendor procedures for use during the outage. The inspectors reviewed AP-3.3 and noted that it provided similar levels of technical and safety reviews which are normally applied to licensee procedures. The inspectors reviewed the implementation of the AP-3.3 for several refueling and steam generator inspection procedures, and noted that the process was effectively used in approving the procedures.

The inspectors reviewed the extent of the operating and refueling procedure revisions and the process used to revise these procedures. These revisions included incorporating previous procedure changes, lessons learned and operator feedback from past shutdowns to improve flexibility in operating the plant and make the procedures easier to use. The inspectors noted several improvements to the format of the procedures such as the development of attachments to cover frequently performed activities and categorizing precautions and limitations by subject which made them more effective for the operators.

The inspectors noted good reviews of these revised procedures with the operators during operator training. This training involved both classroom discussion of the revision and the basis for the revisions as well as simulator use of the procedures for the more significant changes.

The inspectors reviewed selected portions of the operating procedures to verify that plant operation was consistent with the licensing basis. In particular the inspector reviewed collapsing the pressurizer bubble and de-energizing residual heat removal suction valves when the reactor coolant system is depressurized.

Nuclear Safety Evaluation (NSE) 95-3-044 was prepared by the licensee to evaluate operation of the plant with a pressurizer bubble in the cold shutdown condition with containment integrity relaxed. The inspectors verified that the requirements specified in NSE 95-3-044 for relaxing containment integrity were appropriately reflected in plant operating procedure (POP)-4.1, Operation At Cold Shutdown. However, the inspectors noted that operation of the RHR suction valves MOV-730 and MOV-731 per POP 4.1 was not consistent with the FSAR. This is discussed in more detail in section O3.1 of this report.

The inspectors reviewed the refueling procedures to ensure that they were prepared in a manner to ensure plant safety during core alterations. The inspectors verified on a sampling basis that the core reload sequence was in accordance with the operating cycle 10 core analysis. The inspectors also reviewed refueling procedure (RP)-3, Reactor Core Refueling, and RA-27.2, Internal Transfer of Fuel Assemblies and Inserts, to assess the process for controlling fuel movement. Several discrepancies were noted by the inspector during a review of the fuel transfer form generated to place new fuel assemblies into the spent fuel pool. These are discussed in more detail in section E3.1 of this report.

c. Conclusions

A good effort was undertaken by the licensee to revise operating and refueling procedures prior to the upcoming refueling outage. These revisions incorporated previous lessons learned and operator feedback, and revised the format of the procedures to make them easier to use and provide more flexibility in operating the plant. However, two violations of NRC requirements were identified and are discussed in sections O3.1 and E3.1 of this report.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) LER 50-286/97004: the fuel storage building emergency ventilation system was inoperable during movement of the cask crane over the spent fuel pit due to failure to perform all required testing. This item was covered in detail in section O1.4 of this report.

II. MAINTENANCE

M1 Conduct of Maintenance

M1.1 General Comments (62707)

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

WR 96-07500-01,	Excavation to Determine Location of Piping, Duct Banks and Cables
WR 92-01870-15,	Install Temporary Valve and Piping from Head of 32 Emergency Diesel Jacket Water Cooler to Floor Drain
WR 97-00009-01,	Troubleshoot 31 Control Room Air Conditioning Unit
WR 96-05675-00,	31 Instrument Air Compressor Annual Inspection
WR 97-02092-00,	31 Charging Pump Preventive Maintenance
WR 93-01603-11,	Fuel Transfer System Modification
WR 97-00786-00,	CH-405 Charging Pump Discharge Leak Back Past Seat
GNR-004-EL,	Quarterly Preventive Maintenance for Emergency Diesel Generator

The inspectors observed that the work performed under the above work requests (WR) was generally conducted satisfactorily and in accordance with applicable maintenance and administrative procedures. The inspectors also reviewed the licensee implementation of the Maintenance Rule for selected activities, as documented in section M2.1.

However, during this inspection period, the inspectors noted several instances in which the impact of outage related activities on plant operations were not appropriately assessed. These activities included the planned installation of a temporary modification on 33 emergency diesel generator, the erection of scaffolding around containment spray and service water pumps, the temporary storage of equipment in the emergency diesel generator rooms, the excavation around service water piping, and the removal of lagging from the pressure control valve to the steam driven auxiliary feedwater pump.

Some of these examples indicated weak oversight of plant activities during a period when the work activity in the plant significantly increased while the plant continued to operate. Others indicated weakness in the work control processes of generic work, which did not assure that safety-related equipment would not be impacted. Generic work is work in which similar activities are governed by a single work request such as roof repairs and lagging removal. The process to ensure that excavation would not impact safety related equipment was another example in which the work control process was weak. The licensee, however, was taking appropriate steps to ensure that "generic" work would be properly controlled. These issues are discussed in the sections that follow.

M1.2 Temporary Modifications of Emergency Diesel Generators

a. Inspection Scope (37551, 62707, 71707)

The inspector observed the maintenance associated with the installation of a temporary modification to the 32 emergency diesel generator (EDG) and reviewed the scheduling of the temporary modifications for the 31 and 33 EDGs. Also, the nuclear safety evaluation for the associated temporary modification was reviewed.

b. Observations and Findings

The licensee installed a temporary modification on the 32 EDG to support refueling outage work on the EDG service water discharge piping and valves. The temporary modification consisted of installing a four-inch valve and piping on the EDG jacket water cooler. During normal operation, EDG cooling would be through the normal service water piping. During outage work on the service water discharge piping and valves, the four-inch valve would be opened and EDG cooling would be through a 24-inch room drain.

The inspector reviewed the associated nuclear safety evaluation and discussed the temporary modification with the system engineer. Overall, the nuclear safety evaluation was technically sound. The safety evaluation considered effects on equipment seismicity, service water flow balancing, EDG room drain capacity and EDG cooling requirements. Temporary operating procedure TOP-131, revision 0, "Emergency Diesel Generator Operation with Temporary Service Water Return Lines," was appropriately developed to operate the 32 EDG in this modified configuration.

The temporary modification was performed while the 32 EDG was out of service for its quarterly preventive maintenance. The additional work did not significantly change the EDG outage time. However, the inspector noted that similar modifications were planned for the 31 and 33 EDGs, for which quarterly preventive maintenance was not scheduled. Although the temporary modification installation was coordinated with a monthly surveillance test, the maintenance activity was scheduled for 12 hours as compared to a one-hour test run of the EDG. Additionally, the documentation for this intentional entry into a technical specification limiting condition for operations simply stated that the surveillance was required for technical specifications. The benefit of taking the EDG out of service for the temporary modification did not specify whether a net safety benefit gain would be achieved from performing this work at power rather than during the outage.

The inspector raised this concern to licensee management. The licensee indicated the preventive maintenance on the EDGs was originally scheduled with the installation of this temporary modification, however, the schedule was subsequently revised. With regard to the 31 EDG, the licensee indicated that there was a net safety benefit because the 31 EDG was associated with one of the residual heat removal pumps and it would be more prudent to remove the 31 EDG at power than

while shutdown and relying upon shutdown cooling. However, the inspector noted that a number of components were impacted if the 31 EDG was removed from service at power, and that the ability existed to schedule the modification during the outage when steam generators were available for decay heat removal or when RHR was not required. Regarding the 33 EDG, the licensee concluded that there was no net safety benefit involved with removal of the 33 EDG with the plant at power. Consequently, the licensee removed the installation of the 33 EDG temporary modification from the on-line maintenance schedule.

The inspector determined that the documentation justifying the removal of the 31 and 33 EDGs was inadequate. The licensee initiated DER 97-0998 to document this discrepancy. Also, the basis for the 31 EDG, which was subsequently explained to the inspector, was not clearly understood by key personnel associated with the determination that the voluntary entry into the limiting condition for operation was appropriate. The temporary modification of the 33 EDG was subsequently performed when the plant reached cold shutdown.

c. Conclusions

The nuclear safety evaluation associated with the temporary modification on the emergency diesel jacket water coolers was sound. However, the decision to intentionally enter a technical specification limiting condition for operation was weak in that the basis that a net safety benefit would be achieved was not clearly understood by key licensee personnel, was not appropriately documented, and was inappropriate for the 33 emergency diesel generator.

M1.3 Plant Lagging Removal

a. Inspection Scope (62707, 71750)

During an NRC management tour, the NRC noted that the lagging was removed from the pressure control valve, PCV-1139, to the 32 steam driven auxiliary feed pump. The inspector reviewed the appropriateness of the lagging removal.

b. Observations and Findings

During discussions with the system engineer, the inspector noted that the lagging removed was controlled by a memorandum generated on April 24, 1997, which identified that the removal of any lagging from the system required informing the environmental qualification engineer and the system engineer. In this particular case, the removal of the lagging was performed without such consultation.

In response to the deficiency, the licensee initiated deviation event report (DER) 97-0908. The as-found condition was determined to not impact system operability based on contact temperatures on the top and the bottom of the pipe. A lack of differential temperature indicated that condensation had not built up in the pipe and that the associated main steam trap was adequately removing condensate. The temperature of nearby environmentally qualified equipment was measured and

verified to be less than 85°F. The licensee's immediate corrective action included reinstalling the lagging and reviewing the extent of condition.

At the end of the inspection period, the DER remained open, but the licensee indicated that the procedural controls would be formalized. The plant was walked down by the licensee to verify no other similar conditions existed. Also, the licensee initiated trend DER 97-0923 to review the conduct of "generic" type maintenance activities (i.e., multiple work activities covered by a single work request, such as scaffolding erection and roofing repairs).

c. Conclusions

The control of lagging removal was weak in that informal guidance was not communicated effectively. The removal reflected weak oversight of activities in preparation for the outage. Also, this event reflected a weakness in the work control process for "generic" work activities.

M1.4 Scaffolding Control

a. Inspection Scope (62707, 71750)

Two scaffolds located near safety related equipment were found constructed in a manner contrary to procedural requirements. The inspector reviewed the licensee's control of scaffolding construction and their response to these identified deficiencies.

b. Observations and Findings

On April 29, 1997, the inspector identified that scaffold around the 31 containment spray pump was not built in accordance with construction services procedure CON-AD-006, Revision 6, "Scaffolding Control." Procedural requirements did not allow scaffolding to be within one inch of safety-related equipment. However, the scaffolding was located within one inch of the containment spray pump suction isolation valve and a one-inch test line. On April 30, the inspector also identified scaffold located within one inch of the 33 and 34 service water pump discharge flanges.

In discussions with licensee staff and after review of the scaffolding program, the inspector noted that process requirements provided generally good control of scaffolding. However, in these specific instances, the implementation of procedural requirements was inadequate. In addition to the inadequate construction of the scaffolding, other procedural requirements were not met which would have provided timely identification of the deficiencies. These are described below:

- Regarding the service water pump pit, a plant supervisor did not recognize that the area contained safety related equipment. Although the service water pump area was identified in the procedure as a safety-related area, the plant supervisor believed the procedure was referring to the upper elevation.

As a result, after the scaffolding was completed, it did not receive an operations review as required by procedure.

- Regarding the containment spray pump area, the construction of the scaffolding was started on April 26, 1997, but was still not completed as of April 29. Procedure CON-AD-006 stated that the erection of scaffolding in safety-related areas should be done in a timely manner to minimize the time partially installed scaffolding is present near safety related equipment. The scaffolding was awaiting metal planks, which were to be used vice wood planks to minimize radioactive waste from the primary auxiliary building. The installation of these planks did not contribute to the seismic qualification of the scaffolding. However, since the scaffolds were red tagged until their completion, they had not yet received a timely operations or engineering review. The licensee was reviewing their process regarding the interim condition of scaffolds for enhancements.

In response to these deficiencies, the licensee initiated deviation event reports (DER) 97-0866 and 97-0913. Additionally, DER 97-0923 was generated to identify a potential trend in problems associated with the preparations for the refueling outage. This trend DER included construction of scaffolding, excavation of service water piping and removal of lagging. Immediate corrective actions taken in response to the scaffolding issues included removal of the scaffolding in the service water pit and adjustment of the scaffolding around the 31 containment spray pump to maintain a minimum one-inch clearance. The structural engineer assessed the deficiencies and determined that the seismic operability was not affected. An extent of condition review was performed by the licensee, including a walk down of all scaffolding to verify compliance with procedure CON-AD-006. No other discrepancies were identified. Scaffolding activities were stopped to brief personnel involved of the discrepancies, procedure CON-AD-006 requirements, management expectations for self-checking and procedural adherence. Additionally, the license reviewed all scaffolds not yet completed, but were awaiting planks, to ensure that the interim condition of the scaffolding met seismic requirements.

c. Conclusions

Although the controls for scaffolding construction were appropriately defined, the implementation of procedure CON-AD-006 was inadequate. This inadequate implementation resulted in the construction of two scaffolds near safety-related equipment in a manner contrary to procedural specifications. In addition, the controls to ensure timely review of the scaffolds were not implemented, which resulted in the licensee's failure to identify the deficiencies. The construction of the two scaffolds in a manner contrary to the procedural specifications and the failure to evaluate the acceptability of these deviations was an example of a violation of procedure adherence requirements. This was an example in which outage-related work activities could have impacted safety-related equipment. **(VIO 97-03-03)**

M1.5 Control of Temporary Equipment

a. Inspection Scope (62707)

The inspector noted temporary equipment staged in the 31 and 33 emergency diesel rooms. The inspector reviewed the appropriateness of this equipment staging.

b. Observation and Findings

On May 7, 1997, the inspector noted temporary equipment staged in the 31 and 33 emergency diesel rooms. Specifically, the temporary equipment was a four-inch valve and piping combination, which was to be installed on the emergency diesel generators as a temporary modification in preparation for the upcoming refueling outage. The specifics of this temporary modification are described in section M1.2 of this report.

The inspector noted that the staging of this heavy equipment was inappropriate. Specifically, one valve and piping combination was tied to electrical conduit associated with the fire protection system in the 31 emergency diesel room. The other temporary equipment was up against the emergency diesel air start line in the 33 emergency diesel room. The temporary equipment was not intended for use for several days. However, at the time of discovery, the temporary equipment had been staged for less than one shift. Although the early identification by the NRC precluded the violation of procedure requirements, the control of temporary equipment in these two cases was weak.

The licensee took immediate corrective actions to remove the temporary equipment from the area. Also the licensee indicated that for interim corrective actions, equipment staging in safety-related areas was prohibited, except when approved on a case-by-case basis.

c. Conclusions

The control of staged equipment in the 31 and 33 EDG cubicles was weak in that the method of storage could have impacted safety-related equipment. The early identification by the NRC of these two cases precluded a violation of procedure requirements.

M1.6 Service Water Pipe Excavation Work

a. Inspection Scope (62707)

The inspection scope involved walkdowns and evaluation of work controls for excavation work in the main transformer yard. The maintenance activity was to locate the supply and return service water lines from the instrument air compressor closed cooling heat exchanger. This work was to support replacement of the service water piping during the upcoming refueling outage.

b. Observations and Findings

On April 5, the inspector observed the service water excavation work in the main transformer yard under work request (WR) 96-07500-01. The inspector noted that no controls or considerations were provided in the instructions to the workers to maintain the seismic qualification of the underground service water piping. This deficiency was described to the control room supervisor and civil design engineering personnel.

The licensee temporarily stopped excavation, after which civil design engineering directed the workers to maintain at least half of the exposed service water piping (approximately 2 inch diameter) in contact with the dirt. Engineering concluded that with this support, seismic qualification of the piping would be maintained. The inspector revisited the work site various times during the inspection period and verified that the service water piping was in contact with the soil.

The inspector noted two principal licensee procedures that provide controls for the preparation of work requests. The procedures were CON-AD-004, Preparation and Implementation of Work Request Packages, and ICP-DD-01, Work Package Planning. Review of both procedures concluded that the only specific controls during excavation work included notification to health physics to sample the soil for contamination and to notify civil/structural engineering when a component is removed which is an integral part of a seismically qualified piping system. This item represented a weakness in the work planning process.

c. Conclusions

The inspectors identified a weakness in the licensee's work planning process, in that the seismic qualification of underground piping during the maintenance activity was not considered.

M1.7 Foreign Material Exclusion Controls

a. Inspection Scope (62707)

The inspectors observed inadequate foreign material exclusion (FME) control during the 31 instrument air compressor preventive maintenance. The inspector reviewed previous examples of poor FME control during maintenance activities and corrective actions taken by the licensee.

b. Observations and Findings

On April 9, 1997, during preventive maintenance (PM) on the 31 instrument air compressor (IAC), the inspector noted that FME practices were not in accordance with procedure requirements. Maintenance procedures SYS-011-GEN, Foreign Material and Chemical Exclusion Requirements For Controlling System Cleanliness During Maintenance Activities, step 4.2.5 and COM-001-IAS, Instrument Air Compressor Annual Inspection, step 2.2 required that all system openings be

covered when work was not in progress and the work area is unattended. However, the inspector noted several openings on the IAC head and crankcase which were not covered during a work break. The inspector notified maintenance of this condition and proper FME controls were restored for the compressor.

The inspectors reviewed past DERs for FME control problems during maintenance on plant components. DER 96-1795 documented that remnants of a rag were found in the oil crankcase reservoir and internal bearings during maintenance on the "B" acid metering pump in August 1996. The maintenance evaluation concluded that the cause of this event was inattention to detail when closing up components and poor FME practices. Corrective actions taken by the licensee included briefing maintenance personnel on this event and the importance of FME control.

The inspector reviewed the FME program as defined in AP-27.2, Housekeeping and Cleanliness of Fluid Systems, and SYS-011-GEN and noted that these procedures established good controls for maintaining FME during maintenance activities. However, while reviewing the 31 IAC and other previous maintenance activities, the inspector concluded that these requirements were not consistently well understood and implemented by maintenance personnel. In particular, issues such as how FME was maintained on components such as the 31 IAC crankcase and the proper methods for identifying and recovering from a loss of FME control were not well understood by all maintenance personnel.

c. Conclusions

The NRC noted a weakness in FME control during maintenance on the 31 IAC in that openings were not properly covered when the work was not in progress and the work area was unattended. Corrective actions from a previous licensee identified FME control issue were ineffective as evidenced by the repetitive occurrence of a similar deficiency on the 31 IAC. The FME program as described in station procedures was sound, however, in some cases it was not consistently well understood and implemented by the licensee staff. This failure to implement FME controls was an example of a violation of procedure adherence requirements. **(VIO 97-03-03)**

M1.8 33 Charging Pump Discharge Check Valve Leakage

a. Inspection Scope (62707)

On April 9, 1997, the inspector observed portions of the inspection and preparations for removal of the 33 charging pump discharge check valves.

b. Observations and Findings

The scope of the corrective maintenance was to remove the bonnet of two 1.5 inch discharge check valves for the 33 charging pump. The reason for the corrective maintenance was to assess the condition of the valve plug and seat.

The inspector noted appropriate supervisory oversight of the work activity. The job supervisor safely coordinated activities, provided procedural expectations, and provided a good pre-job briefing. The mechanics adhered to the governing procedure VLV-039-GEN, Inspection and Repair of Conval Clampseal Piston Check Valves, while removing the bonnet and inspecting the valve plug. The inspection of the valve internals by the job supervisor and the maintenance engineer concluded that the disc seat required lapping due to a badly worn seat, and the disc springs had signs of rubbing on one side. The internals for the valve were subsequently replaced. The workers appropriately reassembled the valve internals and bonnet based on no leak by the seating surface.

The inspector verified the adequacy of the protective tagging order using drawing 9321-F-27363 and tag verification in the field. The inspector confirmed that the assistant operations manager granted approval for single valve protection as required of AP 10.1, Protective Tagging. The inspector discussed the foreign materials controls during lapping of the valve seat with the supervisor. The supervisor had developed a plan to capture the lapping compound with an obstruction in the pipe and continuous vacuum applied during the removal of the obstruction. This activity was deemed to be adequate. Good health physics support was noted through continuous surveys and air monitoring of the work area.

c. Conclusions

The maintenance activity to replace the internals and relap the seat of the discharge check valves for the 33 charging pump was controlled well with good health physics support.

M1.9 Surveillance General Comments

The inspectors observed all or portions of the following surveillances;

3PT-M62,	480V Undervoltage/Degraded Grid Protection System Functional
3PT-CS14A,	Residual Heat Removal System Valve Test
3PT-M13B,	Reactor Protection Channel Functional Test
3PC-R04B1,	Pressurizer Pressure Channel I Calibration
3PT-CS28,	Pressurizer PORV and Block Valve Test
3PT-R32A,	Fuel Storage Building Filtration System
3PT-Q92B,	32 Service Water Pump Inservice Test
SOP-RP-22,	Reactor Fuel Movements within the Spent Fuel Pool

The licensee conducted the above surveillances appropriately and in accordance with procedural and administrative requirements. As applicable, good coordination and communication with the operations department were observed during performance of the surveillance. Procedures supported the timely completion of the surveillance.

M1.10 Inservice Testing of Residual Heat Removal System Valves

a. Inspection Scope (37551)

The inspectors reviewed and observed portions of surveillance test 3PT-CS14A, revision 1, "Residual Heat Removal System Valve Test."

b. Observations and Findings

The inspector observed good operations performance of the test. During the test, control power fuses for valve AC-MOV-731, a residual heat removal (RHR) suction valve, had blown. The operators took appropriate actions and initiated a deviation event report (DER) to address the deficiency.

The inspector identified that the close function of the RHR suction valves, AC-MOV-730 and AC-MOV-731, was measured but had no acceptance criteria. Upon questioning, the inspector determined that the closing function of these valves was not part of the inservice test (IST) program. However, the valves have a safety function to close if reactor coolant system pressure rises above 550 psig when RHR is in service.

In the licensee's IST program basis document, the closing function of the valves was identified to have no safety function for mitigating the consequences of an accident. The inspector concluded that this was an inappropriate determination. Accidents, as applied to the inservice test program, were not limited to those described in chapter 14 of the final safety analysis report (FSAR), but applied to a broad range of possible adverse events at a nuclear power plant. FSAR chapter 9.3 describes the RHR suction valves as remotely operated valves with independent pressure interlocks to isolate the RHR loop from the reactor coolant system. The inspector considered that isolation of the RHR from the RCS system, a high pressure system to low pressure system, was a safety function for mitigating the potential for an intersystem loss of cooling accident.

DER 97-1004 was initiated by the licensee to document this issue. In the interim, the licensee determined that these valves were operable based upon their tested stroke times. This conclusion was appropriately documented in operability determination 97-026.

c. Conclusions

Although overall the IST program was sound, the licensee failed to include the close function of the RHR suction valves in the program. Contributing to this failure was the licensee's inappropriate determination that the close function did not mitigate the consequence of an accident. The failure to include the close function in the scope of the inservice test program was a violation. **(VIO 97-03-04)**

M1.11 Pressurizer Pressure Channel Surveillance Test

The inspectors observed the performance of surveillance procedure 3PC-R04B1, Pressurizer Pressure Channel I Analog Components. This test procedure was a new revision which allowed testing on-line and was being performed for the first time by instrument and control (I&C) technicians. Previously this test had been written for performance in cold shutdown conditions only. The inspectors noted good procedure adherence by the I&C technicians, good communications and test conduct, and good coordination with operations during performance of the test. The inspectors reviewed the procedure and noted that it was clearly written and easy to follow.

The inspectors further reviewed with I&C the process used to rewrite the procedure for performance on-line. The inspectors noted that the rewrite process involved thorough schematic and wiring diagram reviews by I&C engineering, use of similar test procedures to determine appropriate prerequisites and switch alignments, and procedure walkdowns and verifications by I&C technicians prior to approval. The quality of the revised test was evident in the successful initial performance of the procedure.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Fuel Storage Building Crane Failure

a. Inspection Scope (62707)

The inspectors evaluated the adequacy of licensee corrective maintenance, adherence to committed industry standards, and maintenance rule implications for a fuel storage building overhead crane failure on April 2, 1997. The crane's bridge movement failed when a new fuel assembly was attached. The fuel assembly was safely placed in its storage racks approximately 24 hours after the bridge failure.

b. Observations and Findings

The licensee concluded that the fuel storage building overhead bridge crane failed due to a failure of the brake coil. The brake coil failure was the result of rain water which leaked through the fuel storage building roof, and wetted the brake coil. Corrective actions associated with the failure involved a vendor walkdown of the crane to detect other signs of degradation, repairs to the roof (see report detail O1.4), and replacement of the brake coil. Proposed long-term corrective actions include performance of a monthly preventive maintenance activity to run the crane for one hour with periodic inspections, and an upgrade of the bridge, trolley, and hoist brake coils.

The inspector noted that the licensee identified the fuel storage building roof leak (DER 97-0637) prior to the brake coil failure. However, the licensee's review of the potential impact of the roof leak on equipment in the FSB was weak in that

equipment such as the FSB crane was not walked down to evaluate potential degradation due to the leak.

The fuel storage building overhead crane is within the licensee's 10 CFR 50.65 maintenance rule program as a standby, non-risk significant system. The licensee monitors maintenance preventable functional failures for the crane with a goal of less than 2 per operating cycle. Prior to April 2, 1997 no functional failures were recorded for the spent fuel storage building overhead crane. The inspector questioned if the brake coil was a maintenance preventable functional failure. This evaluation by the licensee was still ongoing as of the end of this inspection period and is considered an inspector followup item **(IFI 97-03-07)**.

By letter dated December 6, 1982, the licensee committed to inspect, and maintain the crane in accordance with guideline 6, section 5.1.1 of NUREG 0612. This section of NUREG 0612 states that the crane inspection and maintenance should be in accordance with Chapter 2-2 of ANSI B 30.2-1976, Overhead and Gantry Cranes, with the exception that tests and inspections should be performed prior to use where it is not practical to meet the frequencies of ANSI B 30.2 for periodic inspection and test, or where frequency of crane use is less than the specified inspection and test frequency. The purpose of the inspection and maintenance is to assure that load bearing components are in proper working order, that worn or damaged components are identified and replaced, and that design safety margins are maintained.

The inspector compared the required inspection and maintenance provisions of ANSI B 30.2-1976 with the licensee's procedures. In general, all of the inspections were identified in either procedure CRA-010-GEN, Fuel Storage Building Crane Inspection, or in 3-MD-52, Periodic Inspections of Cranes and Lifting Equipment. The inspector identified that procedure CRA-010-GEN references ANSI B 30.2-1990 versus ANSI B 30.2-1976, with no apparent commitment change noted to the NRC. The inspector also noted that the hook opening and degree twist periodic inspections were not specifically identified in the visual inspection examination criteria of 3-MD-53. These deficiencies are considered an inspector followup item to verify if a commitment change was evaluated by the licensee, and to identify if crane hook examinations in other procedures evaluate twist and throat openings. **(IFI 97-03-07)**

Inspector review of applicable final safety analysis report (FSAR) sections on spent fuel building overhead cranes noted an inconsistency on non-destructive examination (NDE) frequency for the hook. Specifically, the FSAR detailed that NDE is to be performed prior to each use, and licensee procedure CRA-010-GEN required this to be performed annually. The licensee had previously identified this inconsistency between the FSAR and the procedures and had processed an FSAR change with a 10 CFR 50.59 evaluation that was approved on February 28, 1997. The licensee's change to the FSAR was to make the inspection of hooks in accordance with ANSI B 30.2-1976.

c. Conclusions

The licensee performed a weak review of the impact of the fuel storage building roof leaks on equipment within the building. As a result, the bridge crane brake failed due to wetting of the brake coil. An inspector followup item was identified to further review the licensee evaluation of the bridge brake coil failure as a maintenance preventable functional failure and to further review the incorporation of commitments into maintenance procedures.

III. ENGINEERING

E3 Engineering Procedures and Documentation

E3.1 Fuel Handling Procedures

a. Inspection Scope (37551)

The inspectors reviewed the reactor engineering procedures used for fuel handling to support the refueling outage.

b. Observations and Findings

The inspectors reviewed refueling procedure (RP)-3, revision 1, Reactor Core Refueling, and RA-27.2, revision 1, Internal Transfer of Fuel Assemblies and Inserts, to assess the process for controlling fuel movement. Several discrepancies were noted by the inspector during a review of the fuel transfer form generated to place new fuel assemblies into the spent fuel pool.

Transfer form (TF) 1997-001 was generated in accordance with RA-27.2 to control the movement of new fuel into the spent fuel pool. TF 1997-001 was revised by reactor engineering on April 17, 1997, to delete six steps from the fuel movement sequence. However, the inspector noted that this revision was not processed in accordance with RA-27.2, step 4.12.6 in that a Transfer Form Checklist was not generated as required.

The inspector further noted that the process for changing the sequence of steps in a transfer form was not consistent between RP-3 and RA-27.2. RP-3, section 2.2, step 3.23, stated that a Fuel Assembly Handling Deviation Report (FAHDR) shall be generated per RA-27.2 for any deviations from an approved fuel movement sequence listed in a transfer form. RP-3 further stated that the FAHDR was the official means of immediately revising the fuel movement sequence and that all proposed FAHDRs must be approved by a refueling senior reactor operator. However, the inspector noted that RA-27.2 only stated that the specific numbering sequence for off-load and on-load is recommended, and fuel damage, new developments, or other times may preclude use of the exact sequence. The inspectors reviewed these conflicting procedural requirements with operations and reactor engineering personnel and noted that these two groups had not agreed upon

a method for changing the sequence of steps. Subsequently, RP-3 and RA-27.2 were revised to establish a consistent process for changing a fuel movement sequence. The inspectors considered the lack of a consistent method for changing the sequence of fuel handling to be a weakness in refueling procedure quality.

c. Conclusions

The inspectors identified a weakness in refueling procedure quality in that consistent instructions on how to process changes in the sequence of a transfer form were not contained in the refueling and reactor engineering procedures. A revision to delete steps from a transfer form was not processed per procedure requirements. This was an example of a violation involving a failure to implement procedure requirements. **(VIO 97-03-03)**

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) LER 50-286/95015-00/01/02/03: maintenance on emergency diesel generator exhaust fans exceeded the technical specification (TS) allowed outage times. On July 17, 1995, the licensee identified a condition where maintenance on certain emergency diesel generator (EDG) cubicle exhaust fans would result in the EDGs not meeting single failure criteria. This was due to the fact that the two exhaust fans for each EDG were not each powered by their respective EDG. The TS and final safety analysis report (FSAR) do not specifically identify the need for the exhaust fans to support EDG operability. However, the design basis document identified that one exhaust fan is required to support EDG operability.

At the time of this discovery, the 33 EDG exhaust fan 318 had been out of service for maintenance for approximately 162 hours. Fan 318 was the only 33 EDG exhaust fan powered by that EDG, with the other 33 EDG exhaust fan (fan 319) powered by the 32 EDG. In this condition, the licensee determined that a postulated failure of the 32 EDG would also result in the failure of the 33 EDG due to the loss of both of its exhaust fans. Further, the 31 EDG would also eventually fail, since its exhaust fans are powered by the 32 and 33 EDGs. Therefore, the EDGs did not meet the single failure criteria for the period of time when the exhaust fan 318 was out of service. Through a review of operating logs, the licensee determined several other previous time periods when EDG operability did not meet TS requirements due to exhaust fan unavailability during both power operation and shutdown conditions.

The licensee determined that the 33 EDG should have been declared inoperable with a TS allowed outage time of 72 hours while fan 318 was out of service. The licensee determined that TS 3.7.B.1 had been violated since the 162 hour duration of the fan 318 maintenance exceeded the TS allowed outage time.

Corrective actions taken by the licensee included identifying those EDG exhaust fans necessary for EDG operability and specifying that the TS allowed outage times for the EDGs will be entered when these fans are removed from service. The licensee reviewed other safety related equipment and supporting ventilation systems

and took appropriate corrective actions to address similar potential problems. Further the power supplies for the 31 EDG exhaust fans were temporarily modified during the January 1997 forced outage, and the power supplies for all three EDG exhaust fans will be permanently modified during refueling outage 9.

Due to design deficiencies and inadequate TS requirements, EDG exhaust fans were taken out of service for periods of time which exceeded the TS 3.7.B.1 allowed outage time of 72 hours for EDG operability. During these time periods, the EDGs did not meet single failure criteria and postulated single failures of an EDG could have resulted in the subsequent loss of all three EDGs. This apparent violation of NRC requirements will not be cited in accordance with Section VII.B.3 of the NRC Enforcement Policy since it was licensee identified, appropriate corrective actions are planned and have been taken to prevent recurrence, this deficiency was not likely to have been identified by routine surveillance or quality assurance activities and the violation is not reasonably linked to current performance.

E8.2 (Closed) LER 97-003 and URI 97-01-04: design basis of spare battery charger. As documented in inspection report 50-286/97-01, the licensee reported that the use of the spare battery charger (35 Battery Charger) had the potential of placing the plant outside its design basis. The licensee promptly removed the 35 battery charger from use through administrative controls. A comprehensive corrective action plan was developed in response to the issue. This plan included review of past operability, development of contingency plans for using 35 battery charger for replacement of chargers 31, 32, 33 and 34, evaluating seismic classification of the chargers, determining DC equipment needed to be powered two hours after a design basis accident, defining the design basis and revising applicable procedures and FSAR descriptions.

The modification to install the 35 battery charger was performed in 1985. The associated nuclear safety evaluation was inadequate and resulted in placing the plant outside its design basis. However, the licensee's corrective action were comprehensive and should prevent recurrence. The deficiency was identified by the licensee as a result of a voluntary initiative, corrective actions were prompt and comprehensive, the violation was not likely to be identified by routine licensee efforts such as normal surveillance or quality assurance activities and the violation is not reasonably linked to current performance. As a result, this apparent violation of NRC requirements will not be cited in accordance with Section VII.B.3 of the NRC Enforcement Policy.

IV. PLANT SUPPORT

R1 Radiological Protection and Chemistry Controls

Good radiological controls were noted throughout the inspection period. Radiation and contamination areas were properly barricaded and posted and personnel were observed to be complying with radiological work permit requirements.

S1 Conduct of Security and Safeguards Activities

Adequate security measures were implemented throughout the inspection period. Security posts were manned as required and protected and vital area boundaries were maintained.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee management at the conclusion of the inspection on May 22, 1997. 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

Licensee
H. Salmon, Vice President, Nuclear Operations
R. Barrett, Site Executive Officer, Indian Point 3 (IP3)
J. Comiotes, General Manager, Operations
N. Heuberger, General Manager, Maintenance
J. Russell, General Manager, Maintenance
M. Pearson, Operations Manager
J. DeRoy, Director, IP3 Engineering

NRC
D. Dempsey, Reactor Engineer, DRS

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92901:	Followup - Plant Operations
IP 92903:	Followup - Engineering
IP 93702:	Prompt Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

VIO 97-03-01	Technical Specification Required Fuel Storage Building Ventilation Tests Not Performed.
VIO 97-03-02	Appropriate Corrective Actions Not Taken For A FSAR Discrepancy
VIO 97-03-03	Three Examples of a Failure to Establish and Implement Procedure Requirements
VIO 97-03-04	Failure to Include the MOV-730/731 Close Function in the IST Program
IFI 97-03-05	Review Cause of Over Power Delta Temperature Runback
IFI 97-03-06	Scope Review During Refueling Outage
IFI 97-03-07	Review FSB Crane Brake Coil Failure

Closed

LER 95015-00 01/02/03	EDG Ventilation Fan Power Supply Design Deficiency
LER 97003	Plant Outside Design Basis During Use of 35 Battery Charger
LER 97004	FSB Ventilation System Inoperable Due to Incomplete Testing
URI 97-01-04	Further Review 35 Battery Charger Issue

Updated

None

LIST OF ACRONYMS USED

CVCS	Chemical Volume and Control System
DER	Deviation Event Report
DOP	Diotrylphthalate
ECT	Eddy Current Testing
FAHDR	Fuel Assembly Handling Deviation Report
FME	Foreign Material Exclusion
FSAR	Final Safety Analysis Report
FSS	Field Support Supervisor
HEPA	High Efficiency Particulate Air
IAC	Instrument Air Compressor
IFI	Inspector Follow Up
NDE	Nondestructive Examination
NRC	Nuclear Regulatory Commission
NSE	Nuclear Safety Evaluation
NYPA	New York Power Authority
NYS	New York State
ORG	Operational Review Group
PERC	Performance Enhancement Review Committee
PCV	Pressure Control Valve
PDR	Public Document Room
PID	Problem Identification Description
QAP	Quality Assurance Procedure
RP	Refueling Procedure
RHR	Residual Heat Removal
RSRO	Refueling Senior Reactor Operator
SW	Service Water
TF	Transfer Form
URI	Unresolved Item
VIO	Violation
WR	Work Request