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REGION I

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EXECUTIVE SUMMARY

Indian Point 3 Nuclear Power Plant
NRC Inspection Report No. 50-286/96-11

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a eight-week period of resident inspection; in addition, it includes the results of an inservice inspection and effluents program inspection completed by region-based inspectors.

Operations

During this inspection period, the plant continued to be operated in a safe and conservative manner. Operator response to a loss a heater drain pumps was exemplary and avoided a plant trip. The power reduction and isolation of feedwater heaters was well controlled with a good questioning attitude displayed by all personnel. (Sections O1.2 and O1.4)

The quality of corrective actions was mixed during this inspection period. The root cause evaluation for the heater drain pump trip was thorough and captured key barrier failures. The evaluation of personnel response to secondary plant leaks was narrowly focused and did not address several key issues. The cause of blocking open the emergency diesel generator (EDG) fan louvers was not identified and therefore appropriate corrective actions were not ensured. (Sections O1.2, O1.3, M1.4)

The preliminary results from an autopsy following the death of a chemistry technician at electrical Substation C indicated that the cause of death was from natural causes, and not due to electrocution. The licensee continued its investigation into the cause of death and its identification of enhancements to access control to potentially hazardous areas, procedure quality and worker practices. (Section O1.5)

An effective process had been developed and implemented for station cold weather preparations. Equipment deficiencies were properly reviewed for impact on the plant, prioritized, and entered into the work scheduling process. (Section O2.1)

Housekeeping and temporary equipment storage in the primary auxiliary building had declined recently as indicated by several instances where temporary equipment was not secured per the requirements of AP 13.2. (Section O2.2)

Maintenance

Several instances were noted where the work planning and work control processes were not effectively implemented. Work control and temporary lift process weaknesses, and personnel performance issues contributed to the inadvertent trip of the heater drain pumps. There was a lack of sensitivity to the potential safety implications of secondary plant system leaks. Poor contingency planning for a weld channel and containment penetration pressurization system modification resulted in a compensatory measure which could not have been implemented. The inadvertent entry into an EDG limiting condition of operation

(LCO) resulted from an incorrectly planned and scheduled preventive maintenance activity. (Sections O1.2, O1.3, M1.3, and M1.4)

The ISI program documents and personnel qualifications met ASME code requirements. An inspector followup item was initiated regarding excessive secondary plant piping vibrations. (Section M1.1)

The main turbine generator frame loading adjustment was well performed with good oversight and contingency planning. Quality assurance provided good independent oversight and identified maintenance procedure deficiencies for which corrective actions were planned. (Section M1.2)

The non-outage corrective maintenance backlog was substantively reduced in the past three months through an improved focus on problem areas and the effective application of resources. Identification of equipment deficiencies was thorough and prompt. However, equipment reliability issues continue to challenge the plant staff and result in numerous unscheduled equipment outages. An aggressive scope of work has been identified for the upcoming refueling outage. The work activities include significant modifications and upgrades, which if implemented effectively, would address many material condition concerns. (Sections M2.1, M2.2, and M2.3)

Engineering

Several instances were noted in which engineering performance was good. A good questioning attitude was demonstrated by a system engineer in identifying the inadvertent entry into a EDG LCO. The engineering support in developing new surveillance procedures to test the engineered safeguards features time delays was excellent. Good coordination between operations and engineering resulted in a timely and appropriate resolution of the reduction in reactor coolant pump seal return flow. A review of the backlog of engineering work noted that the engineering organization was significantly more effective at completing work. (Sections M1.4, M1.6, E2.2, and E2.4)

However, there were also several instances noted were engineering work was less thorough. The actions taken to evaluate an increasing containment isolation valve stroke time did not fully consider the proximity of the stroke time to the limit or the potential impact on plant operation if the valve should fail. Weak communications in system engineering resulted in the failure to consider the continued degradation of EDG fan screen tack welds when evaluating the availability of the fan. The initial operability evaluation for the 35 fan cooler unit service water leak lacked sufficient basis to support a reasonable expectation of operability within the technical specification allowed outage time due in part to delays in performing non-destructive examinations. The operability evaluation for control room air conditioning service water valve PCV-1296 was based on reasonable but limited information due to plant operating restrictions. However, once the restrictions were lifted, actions were not taken in a timely manner to remove the valve from service and verify its operability. Subsequent valve disassembly revealed that the valve was inoperable. This was a violation of NRC requirements. (Section E2.1, E4.1, E2.3, and E1.1)

Good testing and troubleshooting by the instrumentation and controls department and engineering was noted in response to three recent turbine generator runbacks to understand the cause of the events. However, the analysis of the plant response to these events was not as thorough. (Section E4.2)

The failure to properly update procedures for the control of IVSWS valves would have resulted in portions of the system failing to perform its intended function. This violation of technical specifications was licensee identified and corrected and is a Non-Cited Violation consistent with section VII.B.1 of the NRC Enforcement Policy. (Section E8.1)

Plant Support

Radioactive liquid and gaseous effluent control programs were well implemented, and were sufficient to protect public health and safety and the environment. Reliability of the effluent radiation monitoring systems improved. Maintenance and surveillance of air cleaning and ventilation systems was good. The Offsite Dose Calculation Manual and Annual Radioactive Effluent Release Report were well detailed. An inspector followup item and an unresolved item were initiated to document two discrepancies between the FSAR and the testing methodology of the control room and primary auxiliary building ventilation systems. (Sections R1, R2, R3, R6, R7, and R8)

A review of on-shift dose assessment capabilities was completed in accordance with TI 2515/134 and concluded that dose assessment capability was supported by appropriate procedural guidance and met NRC requirements. (Section P8.1)

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Summary of Plant Status

The plant began this inspection period at full power. On November 5, 1996, a turbine runback to 87% reactor power occurred when a radiation monitor was taken to the test position. The plant was returned to full power on November 6. On November 13, power was reduced to 88% to isolated suspected tube leaks in the 31B and 32B feedwater heaters. Subsequent to heater isolation, operators manually reduced power to 50% in response to a trip of both heater drain pumps. Reactor power was raised to 88% power on November 15. The plant remained at this power level with the feedwater heaters isolated until December 16, when power was raised to 97%. The plant remained at approximately 97% power with the feedwater heaters isolated through the end of the 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 below.

O1.2 Heater Drain Pumps Trip

a. Inspection Scope (62707, 71707, 93702)

On November 13, 1996, the operators initiated a rapid power reduction in response to a secondary plant transient caused by the inadvertent trip of both heater drain pumps. Reactor power was reduced from about 90% to 50%. The inspector reviewed the operators response to the transient, and the licensee's investigation and corrective actions.

b. Observations and Findings

The licensee conducted a post transient evaluation in accordance with administrative procedure AP-21.2, Revision 7, "Post Trip/Transient Evaluation." The licensee determined that an improper temporary lift of a hold tag caused the dump valves from the heater drain tank to the 32 and 33 condensers to open. This resulted in low level in the heater drain tank, which in turn caused the heater drain pumps to trip.

The operator response to the event was exemplary and averted a plant trip. The operator received a low condenser level alarm, which was caused by the admission of steam and hot water from the heater drain tank to the condenser versus an actual low level condition. Based on this alarm, the operator noted that the heater drain tank level was decreasing. The operators diagnosed the equipment problem, recognized the impending trip of the heater drain pumps and initiated a power reduction in less than one minute and before the heater drain pumps tripped. When the heater drain pumps tripped, the feedwater pump suction pressure reached a low of about 375 psig. At 325 psig, the main feed pumps would start to run back. The operators stabilized power at about 50%.

Prior to the event, the licensee was performing maintenance on valve HD-LCV-1127D, the heater drain tank bypass valve to the 31 condenser. Valve 1127D, which was leaking by, was being worked under maintenance work request (WR) 96-06188-00. The initial maintenance holdoff adequately isolated the control air to the valve, while maintaining control air to the other two heater drain bypass valves. However, maintenance requested that operations perform a temporary lift of a hold tag to facilitate disconnecting the control air line to valve 1127D. When this hold tag was temporarily lifted, control air was lost to the other two bypass valves, valves 1127B and 1127C, which initiated the event.

The licensee initiated a level "A" deviation event report in response to this event. The review conducted by the licensee was thorough and identified several barriers which failed to prevent this event. These barriers included the work planning and work control processes, procedure quality and procedural compliance, work practices and knowledge of system interactions.

Regarding the work planning and work control process, the licensee identified that on an identical valve, 1127B, the need to add a swagelok fitting in the control air tubing was not recorded in the associated work package. As a result, this information was not captured when performing work for valve 1127D. The walkdown for the package by the planner did not identify the need to cut the control air tubing to the valve. Additionally, the previous work on valve 1127B was conducted while shutdown, but there was no resolution of the scheduling disparity as to why valve 1127D was to be worked on-line. This on-line work was not identified as a potential trip risk.

Regarding procedure quality and procedural compliance, the temporary lift process was found to lack definitive guidance. The temporary lift process provided no requirements for an independent verification. The use of temporary lifts was not consistently applied. Temporary lifts were used in lieu of revising protection boundaries and for convenience rather than to allow for troubleshooting and testing. Other barriers which failed included the lack of a questioning attitude by operations and maintenance personnel, and the lack of communication between the field support supervisor and the control room.

Numerous corrective actions were identified or completed. Administrative procedure AP 10.1, "Protective Tagging" was revised to restrict and provide additional guidance for the use of temporary lifts. Procedure SPO-SD-03, "Work Scheduling Procedure," was revised to clarify plant risk determinations and to establish consistency in task scheduling. Actions for applicable departments were identified to ensure the adequate use of work request feedback forms, and to clarify the required level of communication between the field support supervisor and the control room. Training was identified to enhance the knowledge of control air processes and the revised requirements for temporary lifts.

c. Conclusions

The licensee's response to this event was prompt and through. The operators response to the transient was exemplary and avoided a plant trip. The root cause evaluation was thorough, capturing key contributing barriers which failed. The significant effort by the licensee to thoroughly understand this causes of the event indicated a commitment to identify and correct process weaknesses and enhance overall personnel performance and understanding of expectations.

However, several work control and temporary lift process weaknesses, and personnel performance issues contributed to the inadvertent trip of the heater drain pumps. Work planning did not specifically capture the need to cut the control tubing and modify the configuration with a swagelok fitting, thereby providing clear instructions to the maintenance workers performing the repair. The work control process also did not clearly identify this activity as a potential trip risk. The temporary lift process lacked appropriate guidance to operators. The multiple opportunities to prevent this event, which were missed by personnel, indicate the need for continued emphasis on maintaining a questioning attitude and attention to detail.

O1.3 High Pressure Feedwater Vent Chamber Leak

a. Inspection Scope (71707, 93702)

On November 15, 1996, during a plant tour of the turbine building, the inspector noted warm water dripping from two locations in the overhead piping near the heater drain pumps. There some large pipes located in the overhead which contained high pressure/temperature steam and water. The inspector reviewed the licensee actions to address the potential personnel safety problem.

b. Observations and Findings

The inspector questioned the on-shift nuclear plant operator (NPO) as to the source of these leaks. The NPO stated that the leaks were coming from the overhead piping, but the source had not been specifically identified due to the lagging. He further indicated that the first leak started two nights ago and the second leak started the night before. The NPO had mentioned these leaks during the morning shift turnover and reemphasized it with the shift manager just prior to his discussions with the inspector.

Since the source of the leaks was unknown due to the lagging and there were large diameter pipes located in the vicinity, the inspector was concerned with the potential for erosion/corrosion and the associated personnel safety hazard. Several people were working or passing through the area. Also, the timeliness in removing the lagging and the fact that the licensee had raised power from about 50% to 90%

after the heater drain pump trip event raised concerns with the appropriateness of the priority by which these deficiencies were being addressed.

The inspector immediately contacted the operations manager, who went to inspect the area. The operations manager had heard of the secondary side leak, but was under the impression that the leak was from a small drain line. Upon observation of the condition, the operations manger directed the shift manager to rope off the area, and elevated the licensee's response to the equipment deficiency.

The licensee's subsequent immediate corrective actions were appropriate. The area was roped off and the lagging was promptly removed. The licensee determined that the leaks were from the piping elbows of the vent chamber drain lines from the moisture separator reheaters. The vent chamber lines are 3-inch piping containing steam at about 300 psig. Non-destructive examination indicated localized wall thinning. The inspector reviewed the radiographs taken to reach this assessment. Engineering and quality assurance groups provided good support in determining the extent of condition. As of the end of the inspection period, the equipment failure evaluation was not yet finalized.

The inspector reviewed the deviation event report (DER), which documented this event. The DER categorized the event as a level "B" for the equipment failure evaluation, and also issued an action commitment tracking system (ACTS) item to the work control group to address the sensitivity and urgency of addressing identified leaks masked by insulation.

The inspector concluded that the DER and the ACTS response was weak, in that the response focused on the problem identification (PID) tag priority process and determined that the PID priority process was adequate. However, neither the DER nor the ACTS item addressed several weaknesses associated with this event. The NYPA staff lacked the appropriate level of urgency and priority to address these deficiencies. The leaking conditions were not communicated to senior licensee management or to system engineering. The removal of lagging, although not required to be prioritized by the PID review committee, proceeded at a slow pace. The potential personnel safety hazard associated with these deficiencies was not fully considered as indicated by the failure to rope off the area and raise power. NYPA management indicated that actions were taken to discuss steam leak issues with the operations shifts, but these actions were not captured in the DER.

c. Conclusions

The inspector considered that the NYPA personnel lacked the appropriate sensitivity to secondary plant leaks. NYPA personnel did not inform senior management or system engineering of the leaks. The removal of the lagging from the leaking piping was not aggressively pursued. Precautions to rope off the area were not taken, and the impact of raising power on the leaks was not considered. The DER response to the sensitivity of NYPA personnel to these types of leaks was weak. The evaluation was narrowly focused and did not address weak communications, the lack of urgency of the site's initial response, and the lack of precautionary personnel safety measures.

O1.4 Feedwater Heater Isolation

a. Inspection Scope (71707)

On November 13, 1996, feedwater heaters 31B and 32B were isolated and bypassed due to potential heater tube leakage. The inspectors observed plant activities involved with reducing plant power and removing the heaters from service.

b. Observations and Findings

Feedwater heater 31B experienced repeated level control problems on the shell side of the heater with condensate level on the shell side slowly rising. Operations subsequently decided to remove this heater from service based on the inability to properly control condensate level, which indicated a potential heater tube leak. System operating procedure (SOP)-FW-5, "Feedwater Heater String Operation at Power," was written to provide the necessary guidance to isolate a feedwater string at power and continue operating the plant.

SOP-FW-5 required that main turbine generator load be reduced to less than 900 MWe (approximately 90% reactor power) prior to isolating the feedwater heater. The inspector observed the power reduction and noted good command and control of the evolution, a well written procedure, good procedure usage, and good communications with other departments such as reactor engineering to coordinate the power reduction.

An excellent pre-job briefing was held by operations prior to removing the feedwater heater string from service. Operations involved other departments such as performance and reliability to review expected plant response while isolating and bypassing the heater string. The evolution was well controlled with good communications between the operators in the field and the control room.

The plant remained at 900 MWe pending review by the main turbine generator and feedwater manufacturers to determine a limit on power operation with the feedwater heaters isolated. Licensee and vendor review determined that the plant could be operated at full load for up to 8 weeks. MTG load was raised on December 16, and eventually limited to 970 MWe (approximately 97% reactor power) due to limitations on the unisolated feedwater heater level control valves.

c. Conclusions

Operations displayed a good initiative to develop a new procedure specifically for isolating the feedwater heaters with the plant online. Procedures used for the evolution were well written with excellent procedure use and communications evident observed during the evolution. The evolution in general was well controlled with a good questioning attitude displayed by all personnel.

O1.5 Fatality at Substation C (93702)

At approximately 2:00 pm on December 17, 1996, the control room received a call reporting an unconscious individual at Substation C in the protected area of the plant. Substation C consists of a 13.8kv/480v transformer and associated distribution panels. The individual was transported offsite to a local hospital where he was subsequently pronounced dead at about 2:52 p.m. Preliminary results from an autopsy indicated that the cause of death was from natural causes.

As of the end of this inspection period, NYPA was still investigating the circumstances surrounding this event. NYPA initiated several interim actions to enhance worker safety while working in the vicinity high energy electrical lines. Lessons learned from this investigation will be reviewed by NYPA for applicability to other similar plant activities.

O2 Operational Status of Facilities and Equipment

O2.1 Cold Weather Preparations

a. Inspection Scope (71707)

The inspectors reviewed the processes developed by the licensee to ensure that equipment important to safety is adequately protected from damage due to freezing during cold weather conditions.

b. Observations and Findings

Station procedure OD-37, "Cold Weather Preparation," provides the instruction for preparing the plant for cold weather conditions. The inspectors noted that this procedure provided a detailed and comprehensive listing of checkoff lists and operability verifications for various steam and electric heating systems and electrical heat trace circuits. Responsibility for completing the equipment operability checks and alignments was divided between several departments such as maintenance and operations, and required to be completed by November 15, 1996. Any component deficiencies noted were required to be identified by a PID tag. An operations cold weather manager was designated by procedure and had overall responsibility for implementation of the cold weather preparations.

The inspectors reviewed the performance of OD-37 with the operations cold weather manager and noted that the responsible departments had completed their portions of OD-37 by November 12, 1996. The inspector reviewed the PIDs generated during the performance of OD-37 and noted that they were properly prioritized for repair with appropriate compensatory actions taken. Deficiencies such as the failure of the fire water storage tank heaters were tracked as station priorities to ensure that repairs were completed in a timely manner. The inspectors toured various areas of the plant during the inspection period and did not have any additional cold weather concerns.

c. Conclusions

An effective process was developed by the licensee to ensure that the plant was prepared for cold weather conditions. Equipment deficiencies identified during these preparations were properly reviewed for impact on the plant, prioritized, and entered into the work scheduling process. Several plant tours confirmed that the plant was adequately prepared for cold weather conditions.

O2.2 Housekeeping and Equipment Storage

a. Inspection Scope (71707)

The inspectors toured the primary auxiliary building (PAB) and assessed the quantity of temporary equipment and its storage.

b. Observations and Findings

During various tours of the PAB, the inspectors found large quantities of temporary equipment stored in the PAB. Much of this equipment was not being used at the time and was not properly secured in place as required by plant procedures. Administrative procedure (AP) 13.2, revision 2, "Temporary Equipment," provides the requirements for the storage of temporary equipment in those plant areas containing safety related equipment. On several different tours of the PAB, the inspectors noted several examples of temporary equipment not stored in accordance with AP 13.2. Examples include an unrestrained high pressure washing cart, several loose equipment storage carts, a loose fire fighting equipment cart and stretcher, and an unsecured welding machine.

The inspectors also noted a substantial amount of temporary equipment and material stored in the PAB which could interfere with operator response to plant events. Examples include tools left behind following work and cleaning supplies (carts, mops, buckets) stored throughout the PAB (in particular the spent fuel pool heat exchanger area).

NYPA initiated several DERs to document the improper storage of temporary equipment per the requirements of AP 13.2 and developed corrective actions to address these deficiencies. NYPA reviewed the requirements of AP 13.2 and determined that they provided good guidance for the storage of temporary equipment. The requirements of AP 13.2 were highlighted in tailgate meetings to increase the knowledge and awareness of licensee staff. NYPA instituted increased management observations for about four weeks to focus attention on the storage of equipment. The storage of equipment in the PAB and other areas of the plant was noted to have improved during this period. However, the inspectors noted an increase in storage problems after these focused management tours had ended.

NYPA reinstituted the management tour program to ensure that AP 13.2 requirements were consistently met.

c. Conclusions

The inspectors concluded that the state of housekeeping and temporary equipment storage in the PAB had declined in the last several months. There were several instances noted where temporary equipment and tools stored in the PAB were not in use and not properly secured per the requirements of AP 13.2. Corrective actions in the form of increased management observation were effective while in place. However, equipment storage problems increased when these management tours were stopped.

O7 Quality Assurance in Operations

O7.1 Final Safety Analysis Report (FSAR) Review (71707)

While performing the inspections discussed in this report, the inspectors independently verified that the licensee operated the plant in a manner consistent with the applicable portions of the Final Safety Analysis Report (FSAR).

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (62707)

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

- WR 96-05415-00, Replace Fuel Storage Building Roughing Filters
- WR 96-07096-00, Troubleshoot PR N43 Dropped Rod Rate Circuitry
- WR 96-06188-00, Repair Heater Drain Tank Bypass Valve to 31 Condenser
- WR 92-02934-07, Modify Zone 2 Nitrogen Supply Valve
- WR 95-05778-07, Install 38 Backup Service Water Pump Motor

The inspectors observed that the work performed under the above work requests (WR) was conducted satisfactorily and in accordance with applicable maintenance and administrative procedures.

M1.2 Mitigation of Main Turbine Generator Vibrations

a. Inspection Scope (62707)

Excessive vibration has been noted on the main turbine generator (MTG) lead box and current transformers (CTs) since plant startup in June 1995. NYPA developed a maintenance procedure to "jack up" the generator during plant operation, in order to determine if changing the loading of the MTG frame would affect these vibrations. The inspector observed this activity.

b. Observations and Findings

NYPA developed maintenance procedure TUR-004-MTG, "Generator Frame/Foundation Foot Load Adjustment," to use the MTG jacking screws to lift the MTG frame. This maintenance procedure was developed based on guidance and instruction supplied by Westinghouse. Performance of this evolution commenced on October 29, 1996.

Due to the potential plant trip risk based on increasing MTG vibrations during the work, operations management determined that this maintenance should be treated as a special evolution. The inspector attended the maintenance pre-job brief and the special evolution briefs with the control room operators and noted an excellent discussion of the maintenance activity and contingency actions to be taken by the mechanics. The inspector noted that there was no discussion among the control room operators as to the desired operator response if MTG vibrations started to increase. The inspector discussed this concern with the shift manager, who subsequently briefed the control room operators.

Good coordination was noted between system engineering, maintenance, performance and reliability, and operations during the work. Good management oversight was also evident during the work. Quality Assurance (QA) performed a good surveillance of the work activity and noted several problems with the maintenance procedure. These problems were similar to discrepancies noted by the inspector and included unclear guidance in the order of performing procedure steps, improper sequencing of steps, the incorrect specification of dial indicator ranges and the incorrect size of MTG foundation bolt spacers.

While adjusting the MTG foundation bolting to support the "jacking" of the frame, NYPA noted that the bolting setup was not correct. The foundation bolts were setup during previous foundation work in 1993 with spacers to provide clearance between the bolt and the frame. This clearance is intended to allow the MTG frame to float on the foundation. NYPA found that this clearance was not present for many of the foundation bolts, which changed the vibration characteristics of the frame. NYPA further found that the breakaway torque for many of the foundation bolts varied greatly and often no longer met the vendor recommended torque values established in 1993.

While loosening the east side foundation bolts, a significant decrease in vibrations was noted, indicative of the fact that the MTG frame was not floating on the foundation as intended. NYPA noted an increase in vibrations while lifting the east side of the frame, otherwise little change in MTG vibrations was noted while adjusting the frame loading using the jacking screws. After the "jacking" evolution, NYPA restored the foundation bolts to the proper configuration including proper clearance and torque. This allowed the MTG to float on the foundation as designed, and resulted in lower and more consistent vibrations levels.

NYPA initiated DERs to evaluate why the foundation bolting configuration as found condition did not meet vendor recommendations and to determine the cause of the poor work planning associated with the development of the maintenance procedure. NYPA maintenance determined that the procedure user validation and field use validation features of AP-3, "IP3 Procedure Preparation, Review, and Approval," were not effectively used in the preparation of the maintenance procedure. NYPA found that these processes were not widely used and generally misunderstood by maintenance procedure writers. Corrective actions included discussing the use of these validation processes with procedure writers and the development of department guidance for the field use validation. The cause of the MTG foundation bolting configuration change was still under review by the licensee.

The inspector reviewed the initial preparation of maintenance procedure TUR-004-MTG and its associated revisions and temporary procedure changes against the requirements of AP-3. The inspector verified that the user validation process was optional for procedure preparation and that except for a few minor deficiencies, these procedures and changes were prepared and implemented in accordance with AP-3 requirements.

c. Conclusions

The conduct of the MTG frame loading adjustment was well performed by maintenance and engineering with good oversight and contingency planning. Good independent oversight was provided by QA and resulted in the identification of numerous maintenance procedure deficiencies. These deficiencies were attributed to poor pre-job walkdowns by maintenance and poor communications between NYPA and Westinghouse in developing the procedure. Better work preparation and implementation of the user validation process would have resulted in more efficient work performance.

M1.3 Weld Channel Zone 2 Modification

a. Inspection Scope (62707)

The licensee performed a modification to zone 2 of the weld channel containment penetration pressurization system (WCCPPS). This modification included the replacement of the backup nitrogen pressure regulator. The inspector observed the coordination and performance of the maintenance activity.

b. Observations and Findings

The maintenance activity was implemented appropriately and in accordance with procedural and administrative requirements. However, the inspector noted that the physical work on the system was delayed several hours after the system was tagged out and declared inoperable. Discussions with the maintenance supervisor indicated that, prior to starting the physical work on the system, a contingency was set up near the 80′ containment air lock door. This contingency involved the setup of a temporary nitrogen supply. Due to ongoing entries into containment, the licensee was concerned that if the air supply to WCCPPS zone 2 failed, the containment door integrity could not be promptly verified (pressurized to 43 psig) upon the closure of the airlock door as required by technical specification. The inspector considered this contingency to be a good precaution, however, pre-staging the contingency before tagging out the nitrogen back system would have minimized the length of time in which the system was in a limiting condition for operation (LCO).

The inspector reviewed the ability of operations to implement the contingency. The control room supervisor stated that there were no procedures to allow the connection of the temporary air supply to the airlock. He further stated that he had not objected to the contingency setup as long as it was not connected to any permanent equipment, but that he would not implement the contingency without adequate guidance or procedure. The system engineer, who recommended the inclusion of the contingency into the work package, was not aware that the contingency could not be implemented because of the absence of supporting operations procedures.

c. <u>Conclusions</u>

The implementation of the contingency for the WCCPPS modification was not well coordinated between maintenance, engineering and operations. The length of time the system was in an LCO could have been minimized if the staging of the contingency was performed before tagging the system out. The contingency could not be operationally implemented due to the lack of procedures to support the activity. Although this was known by operations personnel, this was not communicated well or resolved before commencing work.

M1.4 <u>Emergency Diesel Room Fan Louver Blocked</u>

a. <u>Inspection Scope (62707)</u>

During a walk down on November 14, 1996, a system engineer noted that the louvers for the 32 emergency diesel generator (EDG) room fan 316 were blocked open during maintenance on the fan. With the louver blocked open, the licensee determined that a 72 hour technical specification (TS) limiting condition of operation (LCO) had been inadvertently been entered for the 32 EDG. The inspectors reviewed the work planning and work control processes to determine the cause of this unplanned LCO entry.

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

The 316 fan had been taken out of service on November 14 to implement a design change to correct cracked tack welds on the screen. These cracked screen welds had contributed in part to the catastrophic failure of 31 EDG room fan 314 on October 14, 1996. The 32 EDG room ventilation is provided by fans 316 and 317. Fan 316 is not required to remain operable to support 32 EDG operability, therefore, the fan work was commenced without entering the 72 hour LCO for the EDG.

At approximately 5:00 pm on November 14, a NYPA system engineer noted that the louver for EDG room fan 316 had been blocked open to support the repairs to the fan screen. As documented in NRC inspection report 50-286/96-10, NYPA had previously determined that blocking open or removing an EDG louver fan would degrade the EDG ventilation and place the EDG in a 72 hour TS LCO condition, pending the restoration of the louver. When the 316 fan was discovered blocked open, the control room operators entered the appropriate LCO for the 32 EDG. The blocks were immediately removed to restore the 316 fan louver, and the 32 EDG LCO was exited. The licensee determined that the louver had been blocked open by maintenance personnel since about 2:00 pm, therefore, the 32 EDG met TS operability requirements since the EDG was in the LCO condition for only three hours.

The licensee initiated deviation/event report (DER) 96-2515 to determine the cause of the inadvertent entry into the LCO for the 32 EDG. Work request (WR) 96-06683-14 provided the instruction to perform the design change to the fan screen. Step 2.02 of the work request directed that the louver assembly be removed. When work control personnel reviewed the work package prior to release, they noted that louver disassembly would place the EDG in a LCO condition. Work control personnel stated that they verbally reviewed this with the maintenance supervisor and placed a note in the work package addressing the need to leave the louver intact. According to work control personnel, the maintenance supervisor understood the operational impact of disturbing the louver and would not perform the step. Based on this discussion, the package was released by work control without revising step 2.02 of the work package.

The maintenance supervisor stated that he did not recall any verbal instruction from work control personnel stating that work on the fan louver would place the 32 EDG in an LCO condition. Work was started on the fan for both the design change to the screen and also for a preventive maintenance activity on the fan and louvers. Although maintenance did not remove the louver per WR 96-06683-14, maintenance did block open the louvers as directed by PM procedure FAN-010-VSS, "Inspection of Emergency Diesel Generator Exhaust Fans."

NYPA determined that the cause of the inadvertent entry into an LCO for the 32 EDG was the reliance of verbal communication regarding work on the EDG fan louver, instead of clarifying the written procedure prior to work. Corrective actions taken by NYPA included counselling work control personnel to ensure that work packages are revised when necessary and to not rely on verbal communication.

The NRC reviewed the DER evaluation prepared by the work control group and determined that it had not captured the cause of why the damper had been blocked open and did not specify corrective actions to prevent recurrence. The DER evaluation did not address the fact that PM procedure FAN-010-VSS was planned, scheduled, risk assessed, and released for work with improper instructions to block open the fan louvers without first entering the proper LCO for the EDG. Although the DER evaluation by work control did not provide corrective actions to revise the

PM procedure, the inspector noted that an ACTS item had been initiated by the ORG group for the maintenance department to revise the procedure.

c. Conclusions

A good questioning attitude was demonstrated by the system engineer in identifying the significance of the EDG fan louver being blocked open and taking timely action to correct the condition. The NRC concluded that the work planning and work control processes for the EDG fan 316 screen design change work package were not well implemented in that work control personnel relied on verbal guidance to compensate for improper work package instructions rather than correcting the written procedures. However, the inspectors further noted that the corrective actions taken for this event were not thorough in that the DER evaluation did not identify that an EDG fan PM procedure was the cause of the blocked open louver. The NRC concluded that neither the work planning, scheduling, risk assessment, or operational impact assessments provided an effective barrier to releasing this work which required placing the EDG in a TS LCO.

M1.5 Surveillance General Comments

The inspectors observed all or portions of the following surveillances;

- 3PT-M42, Fire Pump Test
- 3PT-R3B4, Containment Spray Pump #32 Load Sequencer Calibration
- 3PT-M90, Appendix R Diesel Generator Functional Test
- 3PT-M20A, 31 & 33 ABFPs Surveillance and IST
- 3PT-M17, Containment Spray Pump Functional Test

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 surveillances. Procedures supported the timely completion of the surveillance.

M1.6 Engineered Safety Feature Time Delay Relay Testing

a. Inspection Scope (61726)

During this inspection period, the licensee conducted testing of the engineered safety feature (ESF) Agastat time delay relays with the plant at power. This testing is normally performed with the reactor shut down. The inspector observed portions of the testing, and reviewed the adequacy of the procedure to meet the requirements of technical specifications and associated TS Amendment No. 142.

b. Observations and Findings

Amendment No. 142 to the facility operating license DPR-64 revised the safety injection test frequency to accommodate operation on a 24-month cycle. However, the performance of the Agastat time delay relays, although acceptable, often required adjustments and were unpredictable. As a result, the Agastat time delay relay testing remained on an 18 month cycle schedule.

In discussions with the licensee, a contributor to the need for adjustments of the time delay relays was the testing methodology previously used in procedure 3PT-R003B, revision 12, "Safety Injection System Test Breaker/Bus Stripping." This test, which required the plant to be shutdown, timed the breaker actuation following an initiation signal by stationing several personnel with stop watches in the switchgear room. This methodology introduced inaccuracies inherent in having personnel start and stop stopwatches based on indicating lights.

In the recently developed test procedures, the licensee used Doble timers connected across the power supply terminals of the relay coil and across the open test contacts of the relay. This allowed a more precise measurement of the time delay of the relays. Also, the use of the open test contacts precluded the need to actuate the associated breaker.

The inspector observed the test of the 32 containment spray Agastat time delay relay and noted good support by the instrument and control engineer. The technicians appropriately adhered to the procedure and appeared to have a good understanding of the testing methodology. The licensee conducted about 20 separate tests on various ESF components without incident.

c. Conclusions

The engineering support in developing new procedures to test the ESF time delays was excellent. The procedures allowed the testing of the associated Agastat relays within the conditions allowed by the plant and technical specifications. The testing methodology was enhanced to eliminate the measurement errors from the use of stopwatches by using doble timers to sense the initiating signal to the Agastat and the actuation of the relay coil. The testing was conducted on approximately 20 relays without incident.

M1.7 Inservice Inspection Program Review (73753)

a. Inspection Scope (73753)

The scope of this inspection was to assess the inservice inspection (ISI) program as it was previously implemented (1990, 1992) and will be implemented in the April 1997 refueling outage. Due to an extended shut down period at the Indian Point Unit 3 facility, the licensee had extended the ISI second ten year interval to July 1999 per ASME, Section XI, IWA-2430. The Spring 1997 refueling outage will be the beginning of the third period of the 2nd ten year interval. The program was reviewed of the third period of the 2nd ten year interval. The program was reviewed for its compliance with the requirements of the 1983 Edition including addenda through Summer 1983 of Section XI of the ASME Boiler & Pressure Vessel Code, NRC regulations and plant technical specifications.

b. Observations and Findings

The administrative procedures for the IP3 ISI program (AP-49, Rev 3: NuAP-5.2, Rev 2; NEAP-26, Rev 1.) were reviewed and found to be clearly written, detailed in the assignment of responsibilities for program completion and included both ISI and augmented inspection requirements.

The inspectors reviewed the licensee's ISI program for the 2nd 10 year interval. The inspectors reviewed four data packages from the 19990 and 1992 outages, including ISI item numbers B1.40 (Head to Flange weld), B6.30 (Reactor vessel head closure studs), B15.10 (Reactor Coolant System pressure retaining boundary), and B.570 (nozzle to safe end buttwelds). The procedure for hydrostatically testing the RCS, 3PT-R131, Revision 0, was reviewed in detail. All ISI procedures, data sheets, and final dispositions reviewed were found to be in compliance with the code.

The inspectors verified per the ASME Code Section XI, IWA-2000, the Authorized Nuclear Inservice Inspector (ANII) oversight of ASME section XI ISI activities.

The inspectors reviewed three code repair/replacement packages. The procedure for repair/replacement is AP-39, Revision 5. These repair/replacement packages include a circulating water pump, a pin hole leak in a weld in the auxiliary feedwater system and a charging pump fluid flow element. The packages included the appropriate reviews and signatures of cognizant ISI personnel. The packages were reviewed by the NYPA QA organization and the ANII. The packages also included pre and post repair/replacement NDE data as required by Section XI of the ASME Code.

The Steam Generator Eddy Current Inspection Data Analysis maintenance procedure, SGS-013-RCS, Rev. 0 and the Westinghouse Electric Corporation Data Analysis Guidelines, DAT-GYD-001, Rev. 5, were reviewed. These procedures were used in the 1992 inspection of the IP3 steam generators. There were no recordable indications noted in 1992. The proposed steam generator inspection program for R09 was reviewed by the inspectors. The proposed implementation of inspection requirements and regulatory commitments was found to be consistent with NRC requirements.

The inspectors interviewed the system engineers responsible for the feedwater system to discuss the erosion/corrosion issues under conditions where one or more feedwater heaters are taken out of service. This condition results in an increased flow rate in those heaters which remain in service. The licensee's consideration of potential increased velocity jet impingement on the feedwater tubes as a result of increased flow was reviewed and found to be comprehensive. IP3 engineers had performed an in-depth review of this issue and consulted with the appropriate vendors to ascertain that the resulting increase in jet velocities were within the design capabilities.

During a walkdown of the BOP pipe lines, the inspectors observed excessive vibration in the following extraction steam system lines:

1) Preseparator to heater drain tank line:

2) The moisture separator/reheater (MSR) vent changer lines:

3) The extraction steam line which feeds the No. 35 feedwater heater.

The inspectors found the foregoing steam lines to be vibrating at amplitudes not normally found in such systems. The inspectors reviewed the fatigue evaluations performed by the licensee to justify continued operation of the preseparator drain tank line and found that they had recognized the excessive vibration and provided for analytic review of possible fatigue damage. Their review of this problem was reasonable and showed the piping could sustain the continued vibration at that level. Further study may be necessary to confirm the analytic technique used. No analytic evaluation of the vent chamber lines or the extraction steam line had been addressed by plant personnel. The inspectors requested and reviewed an action plan to provide for fatigue evaluation of all lines together with a root cause evaluation of the piping vibration. The action plan also provided for continued monitoring of the vibrating pipe to ascertain that the vibration amplitudes observed will not be increasing. Verification of the completed items in the action plan and further study of the vibration analysis will be left as an **inspector follow up Item (IFI 96-11-1).**

c. Conclusions

The inspectors found the IP3 ISI program to be comprehensive, well organized and thoroughly supported by the NYPA personnel and the ISI vendor.

M1.8 NDE Data Review

a. Inspection Scope (73753)

The scope of this inspection was to review the data packages from previously performed NDE activities review personnel qualifications and determine the effectiveness of the final resolutions of NDE data.

b. Observations and Findings

The inspectors sampled three ultrasonic examination level III overturns to ensure that proper review and disposition of recordable indications were followed. Each overturned indication is reported to plant management via a Deviation Event Report (DER), a process which involves an independent engineering and QA review prior to issue resolution. The inspectors found the resolution process to be thorough and in compliance with station procedures and NRC regulations.

The inspectors reviewed the qualifications and certifications of ISI personnel. They were found to be in compliance with the ASME code of record (1983 plus addenda). Three ISI level II and III nondestructive examiner qualification packages were reviewed. The certification packages training requirements, and physical examination records were complete and prepared in accordance with the ASME code Section XI, IWA-2300.

c. Conclusions

The NDE data and procedures reviewed by the inspectors were found to be well organized comprehensive documents. The NYPA ISI responsible engineer and the NYPA Site NDE Level III have good procedures in place to ensure proper ISI vendor oversight.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Maintenance Backlog

a. Inspection Scope (62707)

In November 1996, the inspector assessed the Indian Point 3 corrective maintenance backlog and the licensee's progress in reducing this backlog. The inspector reviewed performance indicators developed by the licensee in this area, and interviewed NYPA management and personnel.

b. Observations and Findings

The licensee reduced the non-outage corrective maintenance backlog from 1,257 on September 1 to 919 on November 18. This represented a 25% reduction in the backlog in a two-and-a-half month period. At the end of the inspection period, the inspector noted that the licensee had met its goal of less than 700 non-outage corrective maintenance items. The General Manager - Maintenance attributed much of the reduction to increased resources, the fix-it-now (FIN) team, support from operations and the minor maintenance program. Also, he indicated that a significant amount of work was being pulled into the work week schedule, because the available resources exceeded the work in the rolling twelve week schedule. During the month of November, about 180 work activities, which included corrective maintenance work, were completed each week.

The schedule adherence rate was about 90% from September 16 through October 28. During the month of November, the schedule adherence rate decreased to about 75%. The licensee evaluates the schedule adherence rate for each week. The contributors to the reduction in the November schedule adherence rate were emergent work activities, operational events such as the heater drain pump trip and turbine runback, difficulties encountered during the weld channel and containment penetration pressurization system modifications, and inadequate work package walkdowns. Nevertheless, the inspector noted that the overall schedule adherence rate improved from earlier in the year when it was about 67%.

Although the corrective maintenance backlog decreased, the inspector noted that several other indicators showed a flat or increasing trend. These included priority 1-3 work activities, operator work arounds (OWAs) and control room deficiencies. Priority 1-3 work activities are those activities which the licensee considers to be more important. The inspector noted that about 30% of the priority 1-3 work was less than 30 days old, and about 30% of the non-outage corrective maintenance work being completed was priority 1-3. Also, a large number of new non-outage OWAs and control room deficiencies contributed to a flat trend in these areas. For one week ending November 21, fifteen new control room deficiencies and two new operator work arounds were identified. The inspector concluded that the licensee was appropriately focusing on the priority 1-3 work, OWAs and control room deficiencies.

The inspector reviewed the priority 1-3 work, OWAs and control room deficiencies and identified no issues in which the operability of safety equipment was affected. However, the inspector noted one work request involving a containment isolation valve, whose in-service test stroke time was trending higher, but no action was taken. This is discussed in section E2.1

The licensee has developed several indicators in the past months to assess the corrective maintenance backlog. These indicators show an improvement in the reduction of central planning's backlog and in the timely planning of priority 1-3 work. About 60% of the priority 1-3 work was ready to be worked, with 7% in the central planning and the rest on engineering and/or material hold. Similar to the priority 1-3 work, most of the non-outage corrective maintenance work, which were not ready to be worked, were on hold for engineering and/or materials. However, the inspector noted that the licensee was now able to quantify and characterize the work items in the engineering backlog which impacted the corrective maintenance backlog. In response to this information, the licensee added additional resources to the engineering organization and established an engineering support group consisting of 20 engineers. The results of this effort were indicated during the week ending November 21, when the number of OWAs and control room deficiencies on engineering hold were reduced by 2 despite 17 new OWAs and control room deficiencies being identified. Section E2.4 discusses the engineering backlog in more detail.

c. <u>Conclusions</u>

The non-outage corrective maintenance backlog was substantively reduced in the Fall of 1996. During this period, the licensee appropriately worked on higher priority items, and continued to identify plant deficiencies. The licensee's understanding of the engineering and maintenance backlogs resulted in the improved focus on problems areas, and the effective application of resources. Additional resources were added to the maintenance and engineering organizations, and the support from operations was increased. Work was being pulled into the work week schedule as resources allowed. Improvements were noted in the reduction of central planning's backlog and in the timely planning of priority 1-3 work. Although still below the licensee's goals, the schedule adherence rate improved since the beginning of 1996.

M2.2 Material Condition of Systems and Components Important to Safety

a. Inspection Scope (62707)

The inspectors reviewed the recent work history of various components important to safety to assess the overall state of material condition. The inspectors performed this review and assessment based on general equipment categories of active components, such as pumps, breakers, controllers, indicators, and valve operators.

b. Observations and Findings

The inspectors reviewed the work history of the plant from September 1, 1996, to December 20, 1996. The inspector noted that approximately 940 problem identification tags (PIDs) had been generated during that time period and coded as corrective maintenance. Based on several plant walkdowns during the inspection period, the inspectors noted that most equipment deficiencies had been licensee identified by PIDs. The inspectors also noted during the walkdowns that most PIDs in the plant were generally less than a year old.

Of the 940 PIDs reviewed, the inspectors noted that approximately 15% documented problems with the condensate polisher and the water factory. This indicated to the inspectors that the problem identification threshold for the plant was consistent and, independent of the equipment safety significance. The inspectors further noted that 590 of these PIDs had been dispositioned and required work to be completed. Safety significant deficiencies were noted to have been repaired in a timely manner, while those less significant were scheduled for repair. Adequate justification was noted for those PIDs which were cancelled or closed to another PID or work request.

The inspectors noted few recent problems with valve operators and breakers, with the majority of these component failures limited to systems such as the condensate polisher and water factory facilities. The inspector also noted that pumps have been generally reliable, with the exception of persistent seal leakage from the charging pumps.

However, there were several categories of components which experienced degradation and failure, and challenged reliable plant operation. There were numerous temperature, pressure, level, and flow indicator problems which have contributed to the high number of control room deficiencies and operator work arounds. Examples included rod position indicators and the pressure relief tank level indicator. There were problems with safety significant ventilation systems such as for the emergency diesel generators, control room, primary auxiliary building, and containment. In particular, the reliability of the fans and blowers for these and other ventilation systems have caused problems with system operability.

Persistent problems have been noted with the positioners and controllers for various valves, pumps and control circuits. Recent equipment problems included the non-regenerative heat exchanger component cooling water temperature control valve, charging pump fluid drive controllers, and heat trace control circuitry. Finally, reliability problems with instrument air compressors and control room air conditioning compressors have resulted in poor reliability for these systems.

c. Conclusions

The inspectors noted that the prompt identification of equipment deficiencies continued to be good. These deficiencies were promptly entered into the work scheduling system with repairs completed in a manner commensurate with their safety significance. The inspectors noted that a significant portion of equipment deficiencies identified involve systems not important to safety. However, equipment reliability issues persist with components such as indicators, controllers, positioners, ventilation fans and blowers, compressors, and radiation monitors. These equipment deficiencies continue to challenge the plant licensee staff and result in unscheduled equipment outages.

M2.3 Refueling Outage Scope

a. Inspection Scope (62707)

The inspector reviewed the scope for the upcoming refueling outage (RO-9). Fifty specific activities, involving recent equipment issues, were selected to be verified by the inspectors. Although not all these activities were outage related, the inspectors assessed the appropriateness for tracking and timeliness for completing the items.

b. Findings and Observations

The inspector reviewed the outage scope database, which included about 3600 work requests. About 130 new items were still being reviewed to be included in the outage scope, with several new items being identified weekly. The major work items identified for the outage include the replacement of the power operated relief valves, the realignment of emergency diesel room fan supplies, the repair of the generator rotor and replacement of service water piping.

The inspector found that 49 of the items selected were scheduled for the upcoming refueling outage or appropriately tracked for completion while the plant is on-line. Concerning the remaining item, the inspector noted that it was inappropriately coded for refueling outage 10. This item involved the removal of a temporary modification on the reactor coolant loop low flow transmitter. Discussion with the system engineers indicated that they were not aware that the work had been coded for refueling outage 10. Additionally, discussions with a design engineer indicated that there may have been some work activities that were inappropriately recoded from outage-to-be-determined to refueling outage 10. Discussions with several system engineers indicated that they were still in the process of reviewing work which was deferred to refueling outage 10.

c. Conclusions

The licensee has developed an aggressive outage scope for the upcoming refueling outage. The work activities include significant modifications and upgrades, which if implemented effectively, would address significant concerns regarding material condition. The current scope is thorough, however, one work activity was inappropriately coded for refueling outage 10.

III. Engineering

E1 Conduct of Engineering

E1.1 Inadequate Service Water to the Control Room Air Conditioning System (92903)

a. Inspection Scope

The inspectors reviewed licensee event report (LER) 96-13 detailing an event where the plant was outside its design basis due to inadequate service water (SW) flow to the control room (CR) air conditioning system. The inadequate flow was caused by crud buildup above the valve plug which limited the stroke of the SW supply valves.

b. Observations and Findings

As noted in LER 96-13, SW supply valve PCV-1297 was determined to be incapable of stroking more than 11/16 inch open (versus 1-1/4 inches full stroke) due to a buildup of a predominately ferritic crud deposit behind the valve plug caused, in part, by microbiologically influenced corrosion (MIC). As a result, the valve could not pass the calculated 52.5 gpm minimum water flow required under the design basis heat load. A prior opportunity existed to identify this problem in May 1996. However, Maintenance engineering concluded at that time that the shortened valve stroke was per design based on valve vendor stroke information that was calculated using an incorrect SW flow specification. The incorrect SW flow specification stemmed from the failure to reflect in design documents the significant increase in SW flow required to the CR air conditioning system when the ultimate heat sink design temperature was raised to 95 °F in 1989. The inspector noted that the FSAR was properly updated to reflect the revised design flow.

Service water to the CR air conditioning system is supplied via two parallel paths, only one of which is required to be in service at a time. One of the flow paths contains valve PCV-1297 while the other contains similar valve PCV-1296. Valve PCV-1297 was determined to be inoperable on July 31, modified by removal of the valve internals, and declared operable on August 3. However, valve PCV-1296 provided the CR air conditioning service water supply until August 23, when it was removed from service, with an internal inspection of the valve conducted on September 12. From July 31 until August 23, continued operability of PCV-1296 was based on an operability determination conducted in accordance with AP-8, Deviation & Event Reporting and Operability Determination Procedure.

This evaluation indicated that valve PCV-1296 was operable based on: 1) the proper functioning of the valve positioner at mid-stroke, 2) an internal inspection of the valve and proper setting of the positioner five years before, 3) indications that the positioner for PCV-1297 was improperly set in May 1996 which led to the valve plug continuously remaining in a mid-position (the perceived cause of the buildup of crud above the valve plug) and 4) some small margin to the design flow rate due to a downward revision in the calculated maximum design flow rate.

The operability evaluation for valve PCV-1296 was performed with the best information known at the time. Stroking PCV-1296 closed was not deemed a conservative action with PCV-1297 out of service and stroking valve PCV-1296 full open would likely have required a nuclear safety evaluation. However, the September 12th inspection confirmed the existence of a crud buildup behind the valve plug which limited the valve stroke to 1 inch such that it would not pass the required design flow rate.

Subsequent NYPA Engineering evaluation determined that valve PCV-1296 could provide the required design flow rate to one CR air conditioning unit provided operator action was taken to isolate the other CR air conditioning unit within 48 hours. Therefore the control room could be maintained within its design temperature envelope even without supplemental cooling from the non-safety related supplemental air conditioning system. The inspector further noted that the CR air conditioning system is not governed by plant Technical Specifications.

c. <u>Conclusions</u>

After identifying that SW supply flow through PCV-1297 was inadequate, NYPA took prompt corrective actions to modify the valve. NYPA also identified and corrected design basis information errors which contributed to a previous missed opportunity to identify this problem and determined that no other components were affected by these errors. Engineering continued to evaluate whether additional corrective actions need to be taken regarding the source of the crud deposit. However, the inspector noted to Engineering Management that other SW valves which could potentially be affected by this corrosion and crud buildup and not been identified. This evaluation was pending as of the end of this inspection period.

Although the PCV-1296 operability evaluation was based on the best available information known at the time, additional actions were not promptly taken to gain further information on the condition of the valve. Corrective actions to modify PCV-1297 had been completed and the valve declared operable on August 3. However, PCV-1296 remained in service supplying service water to the CR air conditioning units from August 3 to August 23. During this time, NYPA did not take actions to validate the assumptions made in the operability evaluation. These actions were important given: 1) that a known condition adverse to quality existed on identical companion valve PC-1297 which rendered the valve inoperable, 2) the lack of understanding of the cause and build-up rate of the crud deposit, and 3) the fact that response of the valve positioner at mid-stroke is not an indicator of the ability of the valve to stroke fully open if the crud only prevents movement during the final 20% of plunger travel coupled with the need for PCV-1296 to operate at almost the limit of its stroke to provide the required design flow. The NRC noted that there were no technical reasons during this time period to delay taking PCV-1296 out of service. The failure to take prompt corrective actions to address this condition adverse to quality is a violation. **(VIO 50-286/96-11-02).**

E1.2 Plant Equipment Database

a. Inspection Scope (37551)

The inspectors reviewed NYPA's use of and efforts to maintain and enhance the Plant Equipment Database (PEDB), a computerized central file for plant equipment information, including QA classification, used to support maintenance and modification activities. The PEDB was established in 1992 as part of the overall implementation of the Reliable On-line Maintenance Environment (ROME) project and superseded the Master Equipment List (MEL) developed in the mid-1980's as a listing principally of safety-related components. References to the use of the PEDB in-place of the MEL are contained in FSAR Section 16.1.7, dated July 1992, and in correspondence to the NRC dated August 27, 1993; no formal NRC approval of the use of the PEDB was requested nor required by NYPA.

b. Observations and Findings

The PEDB is extensively used by NYPA in support of maintenance and modification work and is directly referenced in administrative procedure AP-9 governing work control. However, because of the hierarchical structure of the PEDB and the method used for component identification, not all the information from the MEL could be transferred to the PEDB; moreover, not all information entered into the PEBD was validated as planned. Additional components which are non safety-related or were added as part of recent modifications also do not always have equipment information and/or QA classification specified in the PEDB due to data entry resource constraints. Past NYPA efforts to comprehensively improve the PEDB to address these information gaps have not been implemented due to higher management priorities.

In order to deal with these acknowledged information gaps in the PEDB, NYPA has devoted additional staff to the work control group to aid in resolving information requests regarding the PEDB. Moreover, NYPA has implemented a policy whereby if the QA classification is not specified in the PEDB and the FSAR, and plant documents and procedures cannot resolve the issue in a timely manner, then the QA classification for the equipment defaults to Category 1. However, this requirement can be modified if components can be identified in, or bounded by, a design document identifying the proper classification.

The inspector reviewed a listing of DERs in 1996 related to the PEDB as well as a 1996 Configuration Information Management (CIM) self-assessment, a 1996 QA surveillance report on work packages, elements of QA audit reports 95-041 and 92-10, and the March 1994 PEDB Assessment and Recovery Plan. The inspector noted that the PEDB contains over 41,000 records, of which 96% have an identified QA category, 72% have the identified manufacturer, and 50% have the identified model number. While these parameters are the critical ones for planning purposes, the overall total does not allow for an efficient response to most emergent work issues. As a result, the information gaps in the PEDB pose a burden on the work control process when emergent work occurs. In order to reduce this burden during emergent work situations, NYPA Design Engineering revised Modification Control Manual (MCM)-6B and companion procedure SED-AD-24, Technical Evaluation of Components and Replacement Items, to streamline the process of determining the QA classification of components.

The inspector noted that most of the DERs in 1996 related to the PEDB address: 1) the failure to update the PEDB when new information is obtained and/or new components are installed, 2) incorrect equipment or manufacturer information in the PEDB and 3) the failure to provide adequate documentation supporting the classification of components not designated in the PEDB. Few DERs dealt with the planned or averted installation of non QA Category I components in the plant where QA Category I (or Category M) was required.

c. Conclusions

For components listed in the PEDB, the database provides the proper QA category for work items, particularly since the QA classifications of equipment in the PEDB are generally conservative. However, due to acknowledged information gaps in the PEDB, special provisions in the work control process are required to ensure that the proper QA category is assigned to work items not already in the PEDB. The interim compensatory measures taken by NYPA have been effective in ensuring that QA Category I (or Category M) parts are installed where required, but some process problems persist as evidenced by the DERs written in 1996 against the PEDB. Additional corrective actions in this area are planned as part of NYPA's efforts to improve the efficiency of the work control process. However, the comprehensiveness of these actions are not yet known and uncertain, in part because of past decisions not to implement comprehensive improvement plans previously prepared for the PEDB due to higher priorities.

E2 Engineering Support of Equipment and Facilities

E2.1 Containment Isolation Valve Stroke Time

a. Inspection Scope (37551)

During the review of the non-outage corrective maintenance backlog, the inspector noted that a work request for a containment isolation valve was cancelled in June 1996. The work requested documented that the valve closure time was trending upward. The inspector reviewed the appropriateness of the cancellation of the work request.

b. Observations and Findings

Work request 96-03456 documented an increasing closure time for containment isolation valve WD-AOV-1786, associated with the vent line from the reactor coolant drain tank. The inspector noted that the basis for the closure of the valve was its past history which showed occasions when the valve closing time reached the alert range and then subsequently returned below the alert range. The cancelled work request notes indicated that the parts to replace the valve were available and therefore no action should be taken at the time. Also, the cancelled work request notes indicated that an engineering deficiency was initiated for the resolution of the trend but was cancelled.

The inspector noted that the containment isolation valve stroke time had increased slowly over a year by about one second. The last performance of the stroke time was conducted in November and showed a closure time of 9.13 seconds. The alert and the action required limit for the valve were both 10 seconds. Both of the containment isolation valves for this vent line are located outside containment with valve WD-AOV-1786 located closer to containment. As a result, if the valve were to be declared inoperable, it could not be repaired without an engineering evaluation to assure that the containment function could be satisfied. Additionally, the line is the only vent path specified by procedure to relieve pressure in the reactor coolant drain tank. Consequently, the ability to vent the reactor coolant drain tank would be challenged by the failure of this valve.

The licensee indicated that the action required limit could be revised to increase the setpoint. Additionally, a memorandum indicated that to perform its function, the valve closure time could be extended to as much as 24 seconds and still ensure that the release limits would be acceptable. The licensee indicated that the valve was scheduled to be overhauled in the next refueling outage. However, the inspector considered that the approach taken for this degrading trend was not proactive.

c. Conclusions

The inspector concluded that when the initial work request associated with this valve was cancelled, the licensee did not adequately consider the proximity of the valve stroke time to its action required level, and the potential impact on plant operation if the valve should fail. Subsequently, the licensee was evaluating extending the action required limits to 24 seconds and the valve had been scheduled for overhaul in the next refueling outage. The inspector considered these actions appropriate to address the increasing stroke time of the valve.

E2.2 Reactor Coolant Pump Seal Return Flow

a. Inspection Scope (37551)

On October 23, deviation event report (DER) 96-2320 documented a problem with reduced reactor coolant seal flow from the 33 reactor coolant pump. The inspector reviewed the licensee's actions to resolve this problem.

b. Observations and Findings

The DER documented reduced seal return flow of about 0.9 gpm from the 33 reactor coolant pump. The seal return flows are normally greater than 1.0 gpm, and operations procedures direct the operators to start shutting down the plant at 0.8 gpm. This reduced return flow periodically occurred on the other reactor coolant pumps, but most notably on the 32 and 33 reactor coolant pumps.

The licensee determined that the cause of the reduced flow was due to the changes in the RCP seal package temperatures. This temperature was affected by the charging system temperature and containment temperature. Excellent coordination between operations, system engineering and vendor representatives were noted throughout the troubleshooting of this problem. Slow and deliberate changes to the seal injection temperatures and reactor coolant system makeups were made to ensure that seal degradation did not occur and also to verify the adequacy of the seal function.

c. Conclusions

The licensee resolution of reduced seal return flows was appropriate and timely. The approach was performed with appropriate forethought to verify the seal integrity and ensure no seal degradation occurred. The coordination between operations and system engineering was effective.

E2.3 Fan Cooler Service Water Leak

a. Inspection Scope (37551)

On December 7, 1996, at approximately 6:30 p.m., a nuclear NPO identified a small leak from a ten inch service water supply line to the 35 fan cooler unit (FCU). The leakrate was quantified by the operator and the system engineer at approximately eight drops/minutes. The leakage from the pipe weld area was within the ASME Section XI inservice inspection (ISI) class 3 boundary. The inspector reviewed the quality and timeliness of the licensee's operability determinations, and evaluated past engineering performance regarding service water system leakage.

b. Observations and Findings

The allowed outage time (AOT) for the 35 FCU in the technical specifications is twenty-four hours. According to NRC Generic Letter 91-18, "Information to

Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability," section 5.5, timeliness of operability determinations should be commensurate with the safety significance of the issue. The AOTs contained in the technical specifications provide reasonable guidelines for safety significance. The service water system engineer completed an operability determination within three hours of the identification of the leak using administrative procedure (AP)-8, "Operability Determination For a Degraded or Non-Conforming Equipment Condition." The operability determination was based on past experience that structural integrity had not been compromised for previous similar service water system leakage, particularly in cement-lined carbon steel piping. The basis further described the historical characterization of the piping flaws. The leak during this operability determination was not characterized by non-destructive examinations (NDE), but visual observations by the system engineer.

The inspector discussed with the licensee whether the operability determination provided reasonable expectation that the service water system structural integrity was maintained based on a visual inspection of the leak site. The licensee did not perform ultrasonic testing of the leak site until approximately six days after identification. The licensee recognized that the NDE was not timely to evaluate this leak and prepared DER 96-2690 on December 13, 1996. Additionally, the system engineer had previous documentation from design engineering providing acceptable flaw size characterizations that assured structural margins, yet this was not an input into the operability determination until December 11, 1996.

On December 13, 1996 the licensee completed a technical evaluation of the flaw and performed a structural analysis which concluded that the area could still maintain design-basis loading. At the end of the inspection period, the licensee was preparing a request for relief from the ASME code per 10 CFR 50.55a(g)6 according to the guidance of NRC Generic Letter 90-05, "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1,2, and 3 Piping."

The inspector reviewed past performance issues with service water piping leakage. NRC Inspection Reports 50-286/96-10, 96-08, and 96-05 recently documented engineering performance with regards to service water piping and component leakage. Generally, the licensee demonstrated an ability to identify and perform timely and well documented technical evaluations. However, in report 50-286/96-05, engineering did not promptly notify operations and plant management of degraded conditions on valve SWN-87-1. Engineering performance during this recent service water leak was weak, since the operability evaluation completed within the TS AOT did not provide reasonable expectation of structural integrity without NDE results.

c. <u>Conclusions</u>

The licensee appropriately identified a service water leak to the 35 FCU. The initial operability evaluations lack sufficient basis to support a reasonable expectation of operability within the technical specification allowed outage time. Delays in performing NDE were experienced and the licensee documented this problem in a DER. However, the evaluation performed approximately six days later concluded that structural integrity of the service water system was maintained. A relief request from the ASME code was planned at the end of the inspection period.

E2.4 Engineering Backlog

a. Inspection Scope (37551)

The inspector reviewed the engineering organization's effectiveness and progress in reducing the engineering backlog. The assessment consisted of document and database reviews, and interviews with the licensee's staff.

b. Findings and Observations

The licensee tracked the engineering backlog through problem identification tags (PIDs) and/or work requests (WRs). Due to the limitations of the available database, the inspector reviewed the engineering backlog in two parts. The first part consisted of engineering work associated with specifically identified maintenance work activities. This work normally resulted from maintenance work activities for which engineering support was subsequently identified. Within the work control process, if a maintenance work activity requires engineering support, it would be placed on an engineering hold. The maintenance work activities primarily consisted of corrective and preventive maintenance, and activities associated with the implementation of modifications. The inspector reviewed the database for all WRs, which were put on or taken off engineering hold for the months of July and November 1996. Based on this data, the following table contains pertinent statistics.

	July	November
WRs Added to Engineering Hold	173	463
WRs Taken Off Engineering Hold	139	423
Net Change in Backlog	+34	+40
WRs Transferred within Engineering	58	132

Regarding the above November data, 132 of the 423 items involved transferring an item from one engineering group to another. Based on a 15% sample of the remaining 291 items, the inspector found a cancellation rate of about 15%. The inspector reviewed the basis for the cancellations and concluded that they were reasonable. The inspector also noted that about 22% of these completed items were priority 1-3 or priority OA (the higher priority category). About 26% of the WRs placed on engineering hold were associated with preventive maintenance. The inspector had the following findings:

- The engineering organization significantly increased its support of maintenance activities in November as compared to July. Work requests for which engineering support was completed increased by three fold. This increase in engineering work activity was consistent with the decline in the non-outage corrective maintenance backlog and the increased work planning associated with the upcoming refueling outage.

- System engineering processed more engineering work to other engineering groups, as evidenced by an increase in the WRs transferred during the month of November. About 90 of the 132 transferred items in November were from system engineering to another engineering group.

- The November backlog associated with the work request holds increased by 40 items. This indicated that the work load and arrival rate of maintenance items had not yet turned for system engineering. However, with the decrease in the non-outage corrective maintenance and the work-off of outage-related work package planning, the arrival rate of engineering work is expected to decline.

The second part of the review consisted of engineering work for which no specifically identified maintenance work activity was associated. This engineering work typically involved material change requests, modification request evaluations, modification development, and responses to questions and evaluations of concerns. The PIDS and WRs associated with this work were coded "J" for the system engineering group. If the WRs were determined to require design engineering or procurement engineering support (such as developing a modification or determining an appropriate material change), the WR would then be closed, and a WR daughter initiated and coded "N". The inspector reviewed the database for all "J" and "N" PIDs and WRs created and completed during the months of July and November 1996. The licensee considered an "N" WR to be "completed" for the purposes of determining the backlog, when the modification package was completed, and the WR was brought to "R" status. The necessary work required for completing the modification turnaround document when the modification is installed was not included in the backlog. The following table contains pertinent statistics.

	July	November
"J" PIDs and/or WRs Initiated	70	54
"N" WRs Initiated	48	92
"J" PIDs and/or WRs Completed	14	208
"N" WRs Taken to "R" Status	16	33
Net Change in Backlog	+87	-95

Based on the above data, the inspector concluded that the engineering organization completed more "N" and "J" WRs in November than in July. In particular, system engineering completed and/or processed significantly more work in November. About 23% of the "J" PIDs and WRs completed in November were priority 1-3 or priority OA. Based on a 10% sample of the 208 "J" work requests completed, the inspector found that the "J" work requests were reasonably evaluated to determine if the issue could be closed, transferred to another engineering group for modification or resolution, or transferred to maintenance for repair. The 92 "N" WRs initiated in November reflected processing and transferral of engineering issues from system engineering to other engineering groups. A 50% sample of the completed "N" WRs indicated that about 31% were priority 1-3 or OA, 6% were appropriately cancelled to an existing WR, and 20% were outage related.

c. <u>Conclusions</u>

The engineering organization was significantly more effective in completing work in November as compared to three months earlier. This increase represented tangible work in the form of engineering evaluations and modification packages. However, the progress in reducing the overall backlog was limited. The overall backlog remained high (about 1400 items) and declined only slightly in November due to the increase in incoming work to address the non-outage corrective maintenance backlog and the corrective maintenance and modification work for the upcoming outage.

E4 Engineering Staff Knowledge and Performance

E4.1 <u>Emergency Diesel Generator Fan 316 Operability</u>

a. <u>Inspection Scope (37551)</u>

While touring the emergency diesel generator (EDG) cubicles on October 29, 1996, the inspectors noted that 32 EDG ventilation fan 316 was caution tagged in the off position. The caution tag stated that the fan should be run for emergency conditions only. The inspectors reviewed the basis for continued availability of the EDG fan.

b. Observations and Findings

The 32 EDG has two ventilation fans. EDG fan 317 is the fan required to remain operable to support operation of the 32 EDG, while fan 316 is not required to support 32 EDG operability. However, catastrophic failure of EDG fan 316 could affect the operability of other safety related equipment in the area. The inspector reviewed the basis for determining that fan 316 was not subject to imminent failure, even if only run during emergency conditions.

EDG fan 316 was deenergized and caution tagged due to cracked tack welds on the fan cage, which were first identified on June 26, 1996. On October 14, 1996, 31 EDG fan 314 catastrophically failed, in part due to cracked welds on the fan cage. After fan 314 failure, the NYPA ventilation system engineer walked down the other EDG fans and noted that the fan 316 cage and tack welds had further degraded since June. However, this information was not relayed to the system engineering supervisor. The supervisor noted the present condition of fan 316, determined that the fan was still available for service and recommended to operations that the fan be caution tagged "off" and only be run for emergency conditions. However, the continued degradation of the fan since June 1996 was not known to either the engineering supervisor or the shift manager when this operability evaluation was made.

The inspector discussed the continued degradation of fan 316 with the system engineer and supervisor. System engineering concluded that the fan was still available for emergency use. Operations management reconsidered the availability of EDG fan 316 based on the new information about the degradation, the evaluation by system engineering and the scheduled repair of the fan. Operations determined that the fan was still available for use and the use of the caution tag to control the operation of the fan was appropriate.

c. Conclusions

Weak communications within system engineering resulted in the failure to consider the continued degradation of EDG fan 316 cage tack welds when evaluating the availability of the fan. Both system engineering and operations reevaluated the operability of the fan and concluded that it would still be available for emergency use. The NRC had no further concerns.

E4.2 Main Turbine Generator Runbacks

a. Inspection Scope (37551)

On October 28, 1996, the plant experienced a main turbine generator (MTG) runback due to the initiation of nuclear instrumentation system (NIS) dropped rod circuitry for power range channel N42. On November 5, 1996, the plant experienced another MTG runback due to the initiation of NIS dropped rod circuitry for power range channel N43. The NRC reviewed the engineering evaluation done for both of these events, commonality between these two events and a previous similar MTG runback on August 14, 1996, and corrective actions taken to prevent recurrence.

b. Observations and Findings

The MTG runback on October 28, was caused by a momentary loss of power from the 31 instrument bus. Power range channel N42 is powered by the 31 instrument bus, which is in turn powered by the 31 static inverter. The channel N42 dropped rod circuitry monitors the reactor power signal from the detector and will initiate a turbine runback if reactor power decreases by 5% in 5 seconds. When power was momentarily lost to the 31 instrument bus, power range channel N42 output went to zero, which initiated the dropped rod turbine runback circuitry. After the runback was secured, the operators noted that the 31 static inverter had automatically transferred to its backup power supply with a blown fuse found on one of the three internal rectifier/inverters associated with the normal power supply.

The 31 static inverter is designed for a "bumpless" transfer from the normal to the backup power supply so that power to the instrument bus should not be interrupted on a loss of the normal power supply. The initial evaluation by NYPA engineering concluded that the momentary loss of power to the instrument bus was caused by the normal power supply fuse failure.

On a loss of the normal power supply due to a supply breaker trip, the static inverter will transfer to the backup power supply in less than 1/4 of an AC cycle and not result in a loss of instrument bus voltage. NYPA engineering determined that the rectifier/inverter fuse failure affected the inverter output such that the degradation was not detected for 1/2 to 1 AC cycle, at which time the inverter transferred to the backup power supply. Troubleshooting by I&C found no other problems with the 31 static inverter and this failure mode was verified by the static inverter manufacturer. Based on the troubleshooting and failure evaluation, the 31 static inverter was returned to its normal power supply and declared operable on October 31, 1996.

The November 5th MTG runback occurred after the radiation monitor R-14 test switch was operated to support a vapor containment/primary auxiliary building ventilation exhaust filtration system test. NYPA engineering postulated that the operation of the test switch caused a voltage spike on the 34 instrument bus, which also supplies power to NIS power range channel N43. This voltage spike caused a dip in the output of channel N43 which actuated the dropped rod MTG runback.

The November 5th runback was similar to the MTG runback which occurred on August 14, 1996, which was initiated by installing the instrument power fuses for radiation monitor R-13. Corrective actions taken by NYPA in response to the R-13 runback included revising the radiation monitor operating procedures to require bypassing the MTG runback circuitry when either installing fuses or operating the power supply breaker. However, these corrective actions only addressed maintenance activities for the radiation monitors and did not address activities such as operating the test switch.

Immediate corrective actions taken by NYPA following the November 5th runback included issuing an operations shift order prohibiting the operation of certain susceptible radiation monitors (same make as R-13/14). NYPA management directed that the R-13 post transient review be reopened and an action plan be developed to determine further corrective actions in response to all three MTG runbacks.

As of the end of this inspection period, NYPA was still evaluating the causes of all three MTG runbacks. Analysis of the 31 static inverter power supply fuse determined that the fuse failed due to overcurrent and not fatigue or age. The cause of this overcurrent condition is still being investigated by the licensee. Troubleshooting of the power range channel N43 dropped rod circuitry by I&C did not reveal any problems with the operation of the circuit. Instrumentation has been installed to monitor all four instrument buses for voltage fluctuations.

c. <u>Conclusions</u>

The NRC reviewed the engineering evaluations for all three MTG runbacks and noted generally good testing and troubleshooting performed by I&C and engineering to understand the cause of the events. However, the NRC noted that the analysis of the plant response to these events was not as thorough.

A subsequent review by the licensee of the maintenance history for the radiation monitors indicated that there had not been a history of runbacks associated with radiation monitor failures. Also the power range channel dropped rod circuitry is designed with a noise filter which is intended to prevent certain types of transient voltage signals from initiating MTG runbacks. The engineering evaluation for the first MTG runback did not fully consider this information and evaluate the proper operation of the runback circuitry. A more detailed evaluation and troubleshooting into the operation of the dropped rod circuitry was not initiated by NYPA until the third MTG runback initiated by radiation monitor R-14.

In addition, the initial engineering evaluation following the November 5th runback did not fully evaluate the cause of the loss of 31 instrument bus or the corresponding plant response. The initial engineering evaluation determined that the cause of the loss of the 31 instrument bus was due to the fuse failure, which resulted in a 1/2 to 1 AC cycle transfer time to the backup power supply. This evaluation provided an input to the basis for placing the static inverter back in service and declaring it operable on October 31. However, the actual plant response to the loss of 31 instrument bus indicated that it took the 31 static inverter at least 30 AC cycles (1/2 second) to transfer to its backup power supply. This discrepancy was not noted by NYPA engineering until after the inverter was placed back in service.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) LER 50-286/95023: "Isolation Valve Seal Water System in a Condition Prohibited by Technical Specifications due to Inadequate Modification Processes". On October 16, 1995, NYPA discovered that two valves associated with the isolation valve seal water (IVSW) system were not controlled or maintained in the correct position. The valves, 1492 and 1493, serve as branch isolation valves and can be used to isolate IVSW to a total of 22 containment isolation valves. The two branches involved are in the section of the system that is required to be manually operated post accident. Modification 83-3-002, performed in 1983, failed to properly update the required procedures to control the valve positions. Although drawings were updated that showed the valves open, the system checkoff list listed them as closed and the system operating procedure did not address opening the valves.

The IVSW system functions to supply water or nitrogen to containment isolation valves at a pressure higher than the post accident containment pressure to limit fission product release in the event of an accident. This system is redundant to the structural integrity and testing that is performed on containment isolation valves to assure their functionality. The IVSW system was not credited in the accident analysis for the calculation of offsite doses. After the identification, the 22 valves associated with the two isolated branches of IVSW were tested for leakage and found satisfactory. Therefore, the safety significance of this event was minimal. However, the system was required to be operable by technical specifications.

The mispositioned valves were identified by a system engineer performing an evaluation of nitrogen usage by the system. NYPA appropriately initiated a deficiency event report and took corrective actions to correct the valve positions in the checkoff list. The long term corrective actions for this event were already completed through improvements to the modification closeout process. The inspector reviewed Modification Control Manual Procedure MCM-19, revision 6, Modification Turnover and Closeout. The inspector concluded that turnover of modifications and update of affected procedures was now proceduralized as part of the modification closeout process.

The inspector determined that the failure to properly update procedures for the control of valves 1492 and 1493 would have resulted in portions of the IVSW system failing to perform the intended function which was a violation of technical specification 3.3.C.a, for operation above cold shutdown. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

E8.2 (Closed) LER 50-286/96015: inadvertent actuation of the 32 auxiliary boiler feedwater pump after closing the 32 emergency diesel generator manual output breaker switch during testing. This event was reviewed by the inspector and documented in NRC inspection report 50-286/96-10. No new information was provided by the licensee event report since the inspector's review.

E8.3 (Closed) LER 50-286/96013 and 50-286/96013-01: plant outside design basis due to inadequate service water to the control room air conditioning units. This event was reviewed and documented in this report.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Implementation of Radioactive Liquid and Gaseous Effluent Control Programs

a. Inspection Scope (84750)

Inspection of this area consisted of: (1) physical walkdown of facilities and equipment, including air cleaning systems; (2) review of selected licensee's procedures, and (3) review of selected radioactive liquid and gaseous discharge permits with respect to Technical Specification (TS)/Offsite Dose Calculation Manual (ODCM) requirements.

b. Observations and Findings

During a plant tour, the inspectors noted that all effluent radiation monitoring systems (RMS) and observed air cleaning systems were operable at the time of this inspection.

The inspectors noted that the effluent control procedures were detailed, easy to follow, and ODCM requirements were incorporated into the appropriate procedures. The inspectors also determined that the gaseous discharge permits were complete, and met the TS/ODCM requirements for sampling and analyses at the frequencies and lower limits of detection established in the TS.

During a discussion with chemistry staff, the inspectors noted that the responsible individuals had maintained and enhanced their knowledge in the areas of: (1) radioactive liquid and gaseous effluent controls; (2) effluent and process RMS; (3) the application of procedures designed to protect the public health and safety, and the environment; and (4) the TS and ODCM requirements.

c. Conclusion

Based on the above observations, reviews and discussions, the inspectors determined that the licensee established, implemented, and maintained effective radioactive liquid and gaseous effluent control programs.

R2 Status of RP&C Facilities and Equipment

R2.1 Effluent/Process Radiation Monitoring Systems (RMS)

a. Inspection Scope (84750)

Inspection of this area consisted of: (1) review of the most recent calibration results; (2) review of RMS upgrading status; (3) review of RMS work orders; and (4) review of trending/tracking analyses for reliability to determine the implementation of the TS/ODCM requirements and the FSAR commitments for the following RMS:

- R-18, Waste Disposal Liquid Effluent Monitor,
- R-23, Component Cooling Heat Exchanger Service Water Monitor,
- R-16A/B, Fan Cooler and Motor Cooler Service Water Return Monitor,
- R-61, Condensate Polisher Effluent Radiation Monitor,
- R-12, Containment Gas Monitor,
- R-20, Waste Gas Disposal System Monitor,
- R-59, RAMS Building Vent Radiogas Monitor,
- R-15, Condenser Air Ejector Monitor,
- R-46, Administration Building Vent Radiogas Monitor,
- 3PC-R49A, Steam Generator Blowdown,
- 3PC-R63, Plant Vent Flow Monitoring System Calibration,
- 3PC-R36, Plant Vent Wide Range Gas Monitor.

b. Observations and Findings

The instrumentation and controls (I&C) and performance departments had the responsibility of performing electronic and radiological calibrations for the above radiation monitors. The chemistry staff performed an in-situ calibration (equivalent to the primary calibration) for radioactive liquid and gaseous effluent RMS using mixed radionuclides in the same matrix and appropriate geometries. The chemistry supervisor evaluated the in-situ calibration results and updated conversion factors (μCi/cc/cpm), as needed. All calibration results reviewed were within the licensee's acceptance criteria.

The inspectors noted that the licensee did not programmatically require a linearity test for each RMS as recommended by ANSI N13.10-1974 and EPRI TR-102644. The licensee acquired a sufficient amount of data during calibration to check linearity. During the inspectors' review of radiological calibration results, the inspectors independently verified several calibration results, including linearity tests and conversion factors. The inspectors performed independent calculations using selected licensee's calibration data and a statistical method (i.e., linear regression) to determine the conversion factor and linearity. The conversion factors calculated by the inspectors compared well to those calculated by the licensee. For these same monitors, linearity calculated by the inspectors was good in each case.

The inspectors discussed the importance of linearity testing with the RMS system engineer and other RMS task force members. The inspectors stated that the determination of the linearity was an important calibration element because the radioactivity in radioactive waste systems during normal plant operations will typically be much lower than the source activities used for RMS calibration. The inspectors also discussed the wide acceptance band currently in place with licensee personnel. Without linearity testing, it is difficult to determine the capability for monitoring at low or high concentrations. The inspectors also noted that the licensee verified one pre-determined operating high voltage based on the vendor's manual and historical data. The inspectors stated that the operating high voltage should be determined using a plateau curve (high voltages vs. count rate) because the optimum high voltage setting may change over time resulting in degraded RMS performance. The licensee stated that the methodology of linearity testing and plateau curves will be reviewed and adopted for the calibration enhancement.

The inspectors noted that licensee management had appointed an RMS system engineer and established an RMS Task Force. The task force was composed of representatives from chemistry, performance engineering, system engineering, and operations. The inspector noted that the RMS Task Force had responsibilities for: (1) trending/tracking analyses for all RMS; (2) improving and maintaining RMS operability; (3) RMS upgrade projects; and (4) recommending corrective actions to appropriate groups.

The inspectors' review of open and closed licensee work orders pertaining to the RMS indicated no recurring equipment problems other than self-rolling filter paper and strip chart recorders. The inspectors also noted that the work orders were completed in accordance with the established schedule.

The inspectors reviewed the RMS operability status. The RMS system engineer compiled the operability status monthly for the effluent/process RMS. The licensee's administrative goal for the operability is more than 95%, that is less than 5% out-of-service (OOS). The following table illustrates the percentage of OOS effluent/process RMS.

MONTH	% OOS in 1996	% OOS in 1995	% OOS in 1994
JANUARY	0.87	27.4	59.4
FEBRUARY	1.09	26.0	48.7
MARCH	3.81	4.7	37.1
APRIL	0.15	12.6	24.8
MAY	0.87	10.1	12.8
JUNE	1.51	4.7	23.2
JULY	2.78	9.7	14.5
AUGUST	2.34	10.9	15.0
SEPTEMBER	3.65	5.6	12.0
OCTOBER	1.92	7.6	12.0
NOVEMBER	1.40	5.6	15.2
DECEMBER	to be determined	9.1	not determined

The inspectors noted that the system engineer evaluated reasons of the OOS for each monitoring system and initiated appropriate corrective actions, such as recalibration, retest, and routine maintenance. The inspectors discussed TS/ODCM requirements and FSAR commitments with the system engineer and task team members and noted that they understood TS/ODCM requirements and FSAR commitments very well. The inspectors noted that the RMS task force conducted very good tracking/trending analyses to improve operability. Through these efforts, the percentage of out of service RMSs decreased greatly from 1994 to 1996, as shown in the above table.

c. Conclusion

The percentage of RMS components out of service decreased greatly from 1994 to 1996. The inspectors considered this improvement to be attributable to the RMS Task Force and assignment of a system engineer to the RMS. Calibration data reviewed were within licensee's established criteria. However, the licensee did not follow standard accepted industry guidance regarding linearity testing. The inspectors discussed this problem with the licensee. They acknowledged the inspectors' concerns and agreed to review the problem.

R2.2 Air Cleaning Systems

a. Inspection Scope (84750)

The inspectors reviewed the licensee's most recent surveillance test results to determine the implementation of TS requirements and FSAR commitments for the following systems:

- TS 4.4, Containment Air Filtration System,
- TS 4.5, Control Room Air Filtration System,
- TS 4.6, Fuel Storage Building Emergency Ventilation System,
- TS 4.13, Containment Vent and Purge System,
- FSAR 5.3, Containment Ventilation System,
- FSAR 9.8, Primary Auxiliary Building Ventilation System,
- FSAR 9.9, Control Room HVAC.

The inspectors reviewed the following surveillance test results:

- Visual Inspection,
- In-Place HEPA Leak Tests,
- In-Place Charcoal Leak Tests,
- Air Capacity Tests,
- Pressure Drop Tests,
- Laboratory Tests for the Iodine Collection Efficiencies.

b. Observations and Findings

General

Although there were questions regarding systems air flow rates, all surveillance test results of the above systems were within the licensee's acceptance criteria established by the test procedures. Test procedures were good.

The inspectors, however, identified one minor improvement concerning the air velocity (fpm) testing methodology. The air velocity in the duct must be measured in order to calculate the air flow rate (air capacity, cfm). The licensee's procedures directed that a manometer with pitot tube be used to measure air flow rates without regard to air velocity. It is a common industrial practice to use direct air flow rate reading devices (e.g., anemometer) rather than a manometer with a pitot tube because it is difficult to read small increments on a manometer at low duct air velocities. The licensee stated that the methodology will be reviewed and incorporated, as necessary.

During review of the TS requirements for the above air cleaning systems, the inspectors noted that the TS required that tests be conducted at either "the accident design flow rates (TS 4.4, 4.5, and 4.6)" or "the operating low rate (TS 4.13)." The terms "accident design flow rate" and "operating low rate" were not defined by the TS or the FSAR.

Control Room Ventilation System

The control room (CR) ventilation system can operate in three modes called normal, 10% incident, and accident or fallout. The FSAR described the 10% incident mode as able to remove radioactive iodines to minimize thyroid dose in case of a radiological event. Section 9.9 of the FSAR described the CR air conditioning, heating, and ventilation system and contained two design basis flow rates, 1,000 cfm and 2,000 cfm, but as noted previously, did not specifically define "accident design flow rate." The CR ventilation system surveillance tests were performed based at 1,000 cfm (10% incident mode) by performance engineering. The inspectors questioned the licensee as to whether the surveillance test had been conducted in the most appropriate mode and whether Section 9.9 of the FSAR was accurate.

After the onsite portion of the inspection, the inspectors held a telephone conversation with licensee staff (including the system engineer) regarding the appropriateness of the CR ventilation system surveillance tests and FSAR content. Licensee representatives stated that their review of the design basis documents for the CR air cleaning system indicated that testing in the 10% incident mode was appropriate because the 10% incident mode will maintain doses within General Design Criteria (GDC) 19 limits for the design basis accidents. During this discussion with the licensee, it became evident that several of the design system flow rates expressed in Section 9.9 of the FSAR were erroneous as the design basis documents indicated that a modification had reduced the CR filter booster fan design flow rate from 2000 cfm to a maximum of 1400 cfm to ensure proper filter efficiency. The inspectors also discussed the lack of clarity and the confusing description of designed flow rates expressed in Section 9.9 of the FSAR. The licensee stated that appropriate changes to the FSAR would be made in the next update submittal **(IFI 50-286/96-11-03)**.

Primary Auxiliary Building / Vapor Containment Ventilation System

One of the design bases of the primary auxiliary building (PAB) ventilation system is to control flow direction of airborne radioactivity from low activity areas toward higher activity areas. Table 9.8-1 of the FSAR noted PAB system component data. Per table 9.8-1, the PAB exhaust fan was rated at 70,000 cfm at standard conditions and the supply fan at 64,900 cfm at standard conditions in order to maintain negative pressure in the area.

There were two 70,000 cfm exhaust fans (Nos. 31 & 32) which were common to both the containment building (also denoted as VC) purge system and the PAB ventilation system. These fans served as back-ups to each other. Table 5.6-1 of the FSAR illustrated system component data, such as 40,000 cfm for the containment ventilation/purge supply fans and the normal flow for containment building purge exhaust.

The licensee's Procedure 3PT-R23H, VC/PAB Ventilation Exhaust Filtration System, was written to verify the integrity and operability of the VC (TS 4.13, Containment Vent and Purge System) and PAB exhaust ventilation filtration systems. Limitations of this procedure stated, in part, "due to the various plant configurations air flow may range from 15,000 to 108,000 (i.e., both exhaust fans in service/supply fan operating, etc.). Maximum air flow through the VC HEPA's shall not exceed 40,000 cfm. Maximum air flow through the PAB HEPA's shall not exceed 67,000 cfm."

During the review of the most recent surveillance test results for the VC/PAB exhaust air flows, the inspectors noted that the air flow rates of Fan Nos. 31 and 32 were 28,973 cfm and 29,871 cfm for the VC and 64,190 cfm and 55,027 cfm for the PAB, respectively. When the licensee's surveillance test acceptance criteria (Step 5.1.2 of Procedure 3PT-R23H, 15,000-108,000 cfm) were applied to the VC/PAB fans, Fan Nos. 31 and 32 passed the surveillance. However, the inspectors noted that if the fan flow rates denoted in the FSAR had been applied as acceptance criteria, none of the fans would have passed the surveillance test. The inspectors questioned whether the surveillance was conducted at "standard conditions" and the licensee was not able to determine that the air flow testings were based on the standard conditions or other conditions, if any, as described in Tables 5.3-1 and 9.8-1 of the FSAR. The inspectors also noted that the PAB supply fans air flow rates were not tested on a routine basis. The licensee was not able to retrieve a document relative to test conditions for supply fans during this inspection.

The inspectors considered the matter of PAB/VC ventilation system testing and the most recent test results to be unresolved pending further review **(URI 50-286/96-11-04)**

c. <u>Conclusions</u>

Although there were questions regarding system air flow rates, all surveillance test results of the above systems were within the acceptance criteria established by licensee test procedures. System/facility air flow rates and/or the plant air balance were not clearly defined either in the TS or in the FSAR. The CR ventilation system was tested in the most appropriate mode of operation. Several CR ventilation system flow rates delineated in the UFSAR were erroneous.

R3 RP&C Procedures and Documentation

R3.1 <u>ODCM Implementation</u>

a. <u>Inspection Scope (84750)</u>

The inspectors reviewed the ODCM implemented at Indian Point Unit 3 including: (1) dose factors, (2) setpoint calculation methodology, and (3) bioaccumulation factors for aquatic sample media. The inspector also reviewed the 1995 and the first part of 1996 Semi-Annual Radioactive Effluent Reports.

b. Observations and Findings

The ODCM provided descriptions of the sampling and analysis programs, which are established for quantifying radioactive liquid and gaseous effluent concentrations, and for calculating projected doses to the public. All necessary parameters, such as effluent radiation monitor setpoint calculation methodologies, site-specific dilution factors, and dose factors, were listed in the ODCM. The licensee adopted other necessary parameters and updated several dose factors as derived from Regulatory Guide 1.109.

The inspectors reviewed the 1995 and the first part of the 1996 semi-annual radioactive effluent release reports. These reports provided data indicating total released radioactivity for liquid and gaseous effluents. The second part of the semi-annual report also summarized the assessment of the projected maximum individual and population doses resulting from routine radioactive airborne and liquid effluents. Projected doses to the public were well below the technical specification (TS) limits. The inspectors determined that there were no anomalous measurements, omissions or adverse trends in the report.

c. Conclusions

Based on the above review, the inspectors determined that the licensee's ODCM contained sufficient specification, information, and instruction to acceptably implement and maintain the radioactive liquid and gaseous effluent control programs. The licensee met all TS/ODCM reporting requirements.

R6 RP&C Organization and Administration

R6.1 Effluent Control Program Organization

a. Inspection Scope (84750)

The inspectors reviewed changes to the organization and administration of the radioactive liquid and gaseous effluent control programs.

b. Observations and Findings

The chemistry staff had primary responsibility for conducting the radioactive liquid and gaseous effluent control programs. Operations, Engineering, Radwaste Operations, and Instrumentation & Controls organizations support the radiological effluent control programs relative to air cleaning systems, radioactive liquid discharges, and radiation monitoring system calibrations. One notable change since the last NRC inspection of the licensee effluent control program was the assignment of a system engineer to RMS oversight.

It was noted to the inspectors that the chemistry department was using a considerable amount of overtime to complete their normal operational duties. The chemistry manager indicated that this matter was being addressed by evaluating potential reductions in departmental responsibilities and/or additional staff. The inspectors noted no inadequacies directly attributable to the current chemistry staffing level. Actions taken towards staff development to ensure organizational depth in effluent control related chemistry activities were commendable.

c. Conclusions

The RP&C organization was adequately staffed to handle normal operational duties and its evaluating workload and staffing changes.

R7 Quality Assurance in RP&C Activities

R7.1 Effectiveness of Quality Assurance Audits

a. Inspection Scope (84750)

The inspection consisted of a review of Quality Assurance (QA) audit reports required by the TS and a review of corrective actions implemented to address audit findings. The inspectors reviewed the 1995 QA Audit Report No., 95-11, "IP3 Effluents Program."

b. Observation and Findings

The inspectors noted that individuals with appropriate backgrounds were used to conduct the audit. The 1995 audit findings focused mainly on administrative aspects of the chemistry program. The audit team noted that timely attention had not been given to RMS trending and RMS maintenance, but, as noted in Section R2.1 of this report, RMS reliability has been significantly improved. No other technical issues of regulatory significance were identified by the licensee audit team. Licensee corrective actions to audit findings were considered to be appropriate.

The inspectors noted that quality control for chemistry measurements was very good.

c. Conclusion

Based on the above reviews, the inspectors determined that the licensee met the QA audit requirements.

R8 Miscellaneous RP&C Issues

R8.1 Review of Final Safety Analysis Report (FSAR) Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the FSAR description highlighted the need for a special focused review that compares plant practices, procedure and/or parameter to the FSAR descriptions.

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the FSAR that related to the areas inspected. The following inconsistencies were noted between the wording of the FSAR and the plant practices, procedures and/or parameters observed by the inspectors.

Section R2.2 of this report noted minor discrepancies pertaining to the Control Room and PAB/VC air cleaning and ventilation system air flow rates denoted in Sections 9.9 and 9.8 of the FSAR respectively.

P8 Miscellaneous Emergency Preparedness Issues

P8.1 <u>On-Shift Dose Assessment Capabilities (TI 2515/134)</u>

During the week of September 30, 1996, a region-based inspector conducted an in-office telephone interview with the licensee in order to carry out the NRC's Temporary Instruction (TI) 2515/134, "Licensee On-Shift Dose Assessment Capabilities". The goal of the TI is to gather information on the licensee's capabilities to perform on-shift dose assessment. It was determined that the licensee does have on-shift dose assessment capability supported by appropriate procedural guidance. Even though the licensee's emergency plan did not specifically commit to having on-shift dose assessment capability, the inspector concluded that the licensee met NRC requirements to be able to perform dose assessment at all times. The results of the evaluation were forwarded to NRC Headquarters personnel.

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 January 9, 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, Plant Manager, Indian Point 3 (IP3)
J. Comiotes, General Manager, Support
N. Heuberger, General Manager, Maintenance
M. Pearson, Operations Manager
J. DeRoy, Director, IP3 Engineering
M. Kerns, Chemistry Manager
D. Mayer, Radiological Engineering Supervisor
P. Primavera, System Engineer
D. Quinn, Radiological and Environmental Services Manager
S. Sandike, Chemistry Supervisor
A. Stewart, Licensing Engineer
T. Tierney, Licensing Engineer

NRC

T. Frye, Resident Inspector
D. Lew, Senior Resident Inspector
R. Rasmussen, Resident Inspector
P. Habighorst, Resident Inspector
R. Barkley, Project Engineer
L. Eckert, Radiation Specialist
J. Jang, Senior Radiation Specialist
D. Silk, Senior Emergency Preparedness Specialist
L. Dudes, Reactor Engineer
A. Lohmeier, Senior Reactor Engineer
G. Wunder, Project Manager

The inspector also interviewed other licensee and contractor personnel.

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 71753:	Inservice Inspection
IP 84750:	Radioactive Waste Treatment and Effluent and Environmental Monitoring
IP 92901:	Followup - Plant Operations
IP 92903:	Followup - Engineering
IP 93702:	Prompt Response to Events at Operating Power Reactors
TI 2515/134:	Licensee On-shift Dose Assessment Capabilities

ITEMS OPENED, CLOSED, AND DISCUSSED

<u>Opened</u>

IFI 96-11-01	Secondary Plant Piping Vibration Analysis
VIO 96-11-02	Failure to Take Appropriate Corrective Actions for PCV-1296
IFI 96-11-03	Minor Errors (flow rates) in figure 9.9-1 of the FSAR
URI 96-11-04	Adequacy of PAB/VC Ventilation System Testing

<u>Closed</u>

LER 95023	Isolation Valve Seal Water System in a Condition Prohibited by TS due to Inadequate Modification Processes
LER 96015	Inadvertent Actuation of the 32 Auxiliary Boiler Feedwater Pump After Closing the 32 Emergency Diesel Generator Manual Output Breaker Switch During Testing
LER 96013 and 96013-01	Plant Outside Design Basis due to Inadequate Service Water to Control Room Air Conditioning System

LIST OF ACRONYMS USED

ABFP	Auxiliary Boiler Feed Pump
ACTS	Action Commitment Tracking System
AOT	Allowed Outage Time
CIM	Configuration Information Management
CFM	Cubic Feet Per Minute
CR	Control Room
CT	Current Transformer
DER	Deviation Event Report
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
FCU	Fan Cooler Unit
FIN	Fix it Now
FSAR	Final Safety Analysis Report
GDC	General Design Criteria
HVAC	Heating, Ventilation and Air Conditioning
I&C	Instrumentation and Control
IFI	Inspector Follow-up Item
IP3	Indian Point 3
ISI	Inservice Inspection
IVSWS	Isolation Valve Seal Water System
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MCM	Modification Control Manual
MEL	Master Equipment List
MIC	Microbiologically Influenced Corrosion
MTG	Main Turbine Generator
NDE	Nondestructive Examination
NPO	Nuclear Plant Operator
NRC	Nuclear Regulatory Commission
NYPA	New York Power Authority
NYS	New York State
ODCM	Off-site Dose Calculation Manual
OOS	Out of Service
OWA	Operator Work Around
PAB	Primary Auxiliary Building
PDR	Public Document Room
PEDB	Plant Equipment Database
PID	Problem Identification Tags
PM	Preventive Maintenance
QA	Quality Assurance
RCP	Reactor Coolant Pump
REMP	Radiological Environmental Monitoring Program
RMS	Radiation Monitoring System
ROME	Reliable On-line Maintenance Environment
RP&C	Radiation Protection and Chemistry

SW	Service Water
TS	Technical Specifications
URI	Unresolved Item
WCCPPS	Weld Channel and Containment Penetration Pressurization System
WR	Work Request
VC	Vapor Containment