U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 87-21

Docket No. 50-271 License No. DRP-28

Licensee: Vermont Yankee Nuclear Power Corporation
RD 5, Box 169
Brattleboro, Vermont 05301

Facility Name: Vermont Yankee Nuclear Power Station

Inspection At: Vernon, Vermont

Inspection Conducted: October 31, 1987 - December 21, 1987

Inspectors: Geoffrey E. Grant, Senior Resident Inspector
John B. Macdonald, Resident Inspector

Approved By: Donald R. Haverkamp 1/8/88
Donald R. Haverkamp, Chief Date
Reactor Projects Section No. 3C

Inspection Summary: Inspection on October 31, 1987 - December 21, 1987 (Report No. 50-271/87-21)

Areas Inspected: Routine inspection on daytime and backshifts by two resident inspectors of: actions on previous inspection findings; physical security; plant operations; maintenance activities; surveillance activities; fuel sipping operations; licensee event reports; NRC bulletin responses; licensee potentially reportable occurrences; periodic reports; and off-site review committee (NSARC) activities. The inspection involved 324 hours.

Results: No unacceptable conditions were identified. The cause of the November 8, 1987 scram (Section 9.1) was maintenance related and appeared to be a compounding of personnel errors. Maintenance on the "B" feedwater regulating valve was uncoordinated and demonstrated the adverse effect that poor control of balance-of-plant maintenance can have on plant operations. Continuing licensee reviews in this area are appropriate. The high pressure coolant injection system inoperability (Section 9.2) demonstrated a potential lack of attention to detail. Licensee corrective actions were responsive. Response to the Unusual Event (Section 9.4) was expeditious and well coordinated.

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TABLE OF CONTENTS

DETAILS

1.0 Persons Contacted

Interviews and discussions were conducted with members of the licensee staff and management during the report period to obtain information pertinent to the areas inspected. Inspection findings were discussed periodically with the management and supervisory personnel listed below.

Mr. P. Donnelly, Maintenance Superintendent
Mr. G. Johnson, Operations Supervisor
Mr. R. Lopriore, Maintenance Supervisor
Mr. J. Pelletier, Plant Manager
Mr. R. Wanczyk, Operations Superintendent
Mr. T. Watson, I & C Supervisor

2.0 Summary of Facility and NRC Activities

Vermont Yankee Nuclear Power Station (Vermont Yankee or the plant) continued full power operations until a high reactor water level caused a reactor scram on November 8, 1987 (section 9.1). The plant remained shutdown for two days for a variety of maintenance activities including a drywell entry to locate the source of increased drywell leakage (Section 10.1). Return to power operations was accomplished on November 10 with power ramps and rod pattern adjustments culminating in 100% power on November 14. A routine rod pattern exchange requiring a power decrease to 55% was performed on December 5. With the exception of a power decrease during the Unusual Event (Section 9.4) on December 15, the plant remained at full power. Throughout the period, weekly power reductions to 90% or 80% were conducted to perform routine control rod drive, main turbine and valve surveillances. Major preventive maintenance was performed on the "A" standby diesel generator (SDG) on December 7-11.

On December 2, 1987, Vermont Yankee Nuclear Power Corporation (VYNPC or the licensee) conducted an unannounced full participation emergency exercise. A Region I based team observed the exercise (Inspection Report 87-22). Mr. John B. Macdonald was assigned as Resident Inspector at Vermont Yankee effective November 8, 1987.

3.0 Status of Previous Inspection Findings

3.1 (Closed) Unresolved Item 87-02-03: Core Spray Safe-end Inspections. During the 1986 refueling outage, VYNPC performed ultrasonic testing (UT) and liquid penetrant testing (PT) examinations of the core spray buttered nozzle-to-safe-end welds in accordance with IE Notice 84-41. Some cracking was found in the Inconel 182 butter of both core spray nozzle-to-safe-end welds. The cracking was assumed to be intergranular stress corrosion cracking. By letters dated May 5 (FVY 86-36) and June 2 (FVY 86-49), 1986, VYNPS proposed to weld overlay repair both cracked core spray nozzle-to-safe-end welds with Inconel 82. By letter dated June 16, 1986, NRC:NRR found the proposed repairs acceptable on an interim basis but recommended that the licensee consider replacing the safe-ends during the 1987 outage. By letter dated January 12 (FVY 87-07) and May 7 (FVY 87-50), 1987, VYNPC informed NRC:NRR of their plans to inspect rather than replace the safe-ends during the 1987 outage. By letter dated May 28, 1987, NRC:NRR approved the inspection plan, providing the results were satisfactory, and requested that VYNPC provide the results within three weeks of plant startup. By letter dated October 20, 1987 (FVY 87-100), VYNPC provided the results of the 1987 outage core spray nozzle-to-safe-end weld overlay inspections. The PT and UT examinations were performed to detect flaws in the weld overlay surface, overlay tapers, overlay base material interface, and safe-end/nozzle base material adjacent to the overlay. Examinations were conducted by qualified Level II and III examiners in accordance with industry and licensee procedures. These examinations showed the weld overlays and the underlying nozzle, weld and safe-end material to be free from new or propagating defects. Based on these results, the licensee concluded that acceptable overlay service had been demonstrated and that replacement of the safe-ends during the 1987 outage was not warranted. The licensee will continue to communicate with NRC:NRR concerning future plans regarding the potential replacement of the safe-ends. This item is closed.

4.0 Operational Safety Verification

The inspector observed plant operations during regular and backshift tours of the following areas:

Control Room	Cable Vault
Reactor Building	Fence Line (Protected Area)
Diesel Generator Rooms	Intake Structure
Vital Switchgear Room	Turbine Building

Control Room instruments were observed for correlation between channels, proper functioning, and conformance with technical specifications. Alarm conditions in effect and alarms received in the control room were reviewed and discussed with the operators. Operator awareness and response to these conditions were reviewed. Operators were found cognizant of board and plant conditions with the isolated exception of the high pressure coolant injection flow indicator (Section 9.2). Control room and shift manning were compared with technical specification requirements. Posting and control of radiation, contaminated and high radiation areas were inspected. Use of and compliance with radiation work permits and use of required personnel monitoring devices were checked. Plant housekeeping controls were observed including control of flammable and other hazardous materials. During plant tours, logs and records were reviewed to ensure compliance with station procedures, to determine if entries were correctly made, and to verify correct communication of equipment status. These records included various operating logs, turnover sheets, tagout and jumper logs, and potential reportable occurence reports. Inspections of the control room were performed on weekends and backshifts including November 2, 3, 4, 5, 9, 10, 12, 13, 19, 20, 23, 24, 25, 30 and December 1, 2, 7, 8, 9, 11 and 21. Operators and shift supervisors were alert and attentive and responded appropriately to annunciators and plant conditions.

4.1 Safety System Review

The emergency diesel generators, residual heat removal, core spray, residual heat removal service water, high pressure coolant injection, and reactor core isolation cooling systems were reviewed to verify proper alignment and operational status in the standby mode. The review included verification that (i) accessible major flow path valves were correctly positioned; (ii) power supplies were energized; (iii) lubrication and component cooling was proper; and (iv) components were operable based on a visual inspection of equipment for leakage and general conditions. No inadequacies were identified.

4.2 Feedwater Leak Detection System Status

The inspector reviewed the feedwater leakage detection system and the monthly performance summary provided by the licensee in accordance with VYNPC letter FVY 82-105. The licensee reported that, based on the leakage monitoring data reduced as of November 27, 1987, there were no deviations in excess of 0.10 from the steady state value of normalized thermocouple readings, with the exception of point #12, and no failures in the 16 thermocouples installed on the four feedwater nozzles. Point #12 is one of three lower thermocouples on the "C" feedwater nozzle and exhibited a slight downward (cooling) trend during the evaluation period. Although low relative to post-1987 outage readings, the current value for this thermocouple is not unusually low when compared to previous cycle readings. The licensee is closely monitoring this thermocouple for further trends and will continue assessment during the present evaluation period.

4.3 Inoperable Equipment

Actions taken by plant personnel during periods when equipment was inoperable were reviewed to verify that: technical specification limits were met; alternate surveillance testing was completed satisfactorily; and, equipment return to service upon completion of repairs was proper. This review was completed for the following items:

November 5, 1987 - high pressure coolant injection was declared inoperable when the flow transmitter was observed reading 400 gpm with the system secured. maintenance request (MR) 87-2892 was generated to vent the flow transmitter. Refer to section 9.2 for more detail.

November 9, 1987 - Reactor core isolation cooling (RCIC) was declared inoperable when the RCIC pump trip throttle valve RCIC-1 failed to trip the turbine. MR 87-2938 was generated to clean and lubricate RCIC-1. Refer to section 7.0 for more detail.

November 14, 1987 - The RCIC was declared inoperable when discharge check valve RCIC-50 failed, causing the RCIC turbine to trip on high exhaust pressure. The MR 87-2991 was generated to perform troubleshooting and the MR 87-3003 was generated to repair RCIC-50. Refer to section 9.3 for more detail.

December 7, 1987 - Standby diesel generator (SDG) A was declared inoperable to perform maintenance not accomplished during the 1987 refueling outage. Refer to section 10.2 for more detail.

December 11, 1987 - Containment spray valve CS-5A was declared inoperable to replace the motor operator motor, which had developed a ground on phase B. The MR 87-3122 was generated to replace the motor.

December 15, 1987 - The SDG B was declared inoperable to perform maintenance not accomplished during the 1987 refueling outage. Refer to section 9.4 for more detail.

December 15, 1987 - Drywell spray discharge isolation valve RHR-26A was declared inoperable when it failed to stroke during alternate testing. The MR 87-3163 was generated to replace the faulted motor operator motor. Refer to section 10.3 for more detail.

Both trains of the toxic gas monitoring (TGM) system were out of service individually and simultaneously repeatedly during the inspection period.

No inadequacies were identified.

4.4 Review of Lifted Leads, Jumpers and Mechanical Bypasses

Lifted lead and jumper (LL/J) requests and mechanical bypasses (MB) were reviewed to verify that controls established by licensee procedure AP 0020, Revision 10 were met, no conflict with the technical specifications were created, the requests were properly approved prior to installation, and a safety evaluation in accordance with 10 CFR 50.59 was prepared if required. Implementation of the requests was reviewed on a sampling basis.

The LL/J index was reviewed for entries since November 1, 1987. Four requests for LL/J authorizations were approved, two have since been restored and two remain active. The LL/J 87-0163, authorized November 2, 1987, was issued to allow lifting of the recirculation pump B high vibration alarm leads. Repetitive spurious alarms had annunciated in the control room. There was no evidence to suggest a pump vibration problem. As a result of this LL/J, the recirculation pump B high vibration alarm was disabled. The MR 87-2741 was issued to facilitate troubleshooting and repairs. Because the pump is inaccessable at power this LL/J will remain active until an outage occurs of sufficient duration to perform the required corrective maintenance.

The LL/J 87-0164, authorized November 9, 1987, was issued to allow lifting and removal of the main steam line B drain trap high level switch due to failure of the trap float assembly. Maintenance removed the float assembly and MR 87-0320 was issued to facilitate repairs. The high level annunciator was disabled. This LL/J remains open. The inspectors had no further questions.

4.5 Review of Switching & Tagging Operations

The switching and tagging log was reviewed and tagging activities were inspected to verify plant equipment was controlled in accordance with the requirements of procedure AP 0140, Vermont Local Control Switching Rules. The following switching and tagging orders were reviewed:

87-8518 - issued for the repair of drywell spray discharge isolation valve RHR-26A (MR 87-3163) (section 10.3).

87-1504 - issued to support preventive maintenance on SDG A (section 10.2).

87-1505 - issued to support preventive maintenance on SDG B. Released when licensee management postponed the maintenance following valve RHR-26A failure (section 9.4).

87-1433, 1434 - issued for the repair of RCIC system components during the two day outage following the November 8, 1987 reactor scram.

The inspectors had no questions concerning switching procedures.

5.0 Observations of Physical Security

Selected aspects of plant physical security were reviewed during regular and backshift hours to verify that controls were in accordance with the security plan and approved procedures. This review included the following security measures: guard staffing; vital and protected area barrier integrity; maintenance of isolation zones; and, implementation of access controls, including authorization, badging, escorting, and searches. No inadequacies were identified.

6.0 Fuel Sipping Results

Inspection report 87-06 identified an increase in offgas system radiation levels beginning on March 18, 1987. The radiation level continued to ramp up until stabilization in mid-April in the 9000 to 10,000 uCi/sec range. The offgas release rate remained well below the Technical Specification 3.8.K.1 limit of 0.16 Ci/sec. Environmental release rates remained far below the Technical Specification 3.8.E.1 limits. Licensee evaluation of the level of activity, the isotopes present and the slope of the isotopic mixture measured from the offgas sample concluded that an equilibrium release mechanism existed, indicative of a pinhole type defect in two or three fuel pins. Based on this data, the licensee made plans to perform fuel sipping operations on approximately 152 bundles during the 1987 outage.

Visual inspection by an onsite General Electric fuel inspection team verified that one fuel pin in a fuel bundle (LJZ-069) pre-selected by the licensee had failed. The failure mechanism was crud induced localized corrosion (CILC). The bundle had been selected for visual inspection by the reactor engineering group based upon core location, bundle exposure and the results of various tests. Subsequent sipping of this bundle confirmed it contained a failed fuel pin. The licensee sipped the remaining fuel bundles in this group (reload 8 fuel) and found another bundle containing a failed fuel pin (LJZ-070). Selected sipping was performed on bundles from reloads 9 and 10 with no identified failures. A total of 105 bundles were sipped. The failed bundles, which were scheduled to be permanently off loaded, were placed in storage in the spent fuel pool. The licensee's conclusion that the extent of failed fuel bundles had been identified and corrected has been supported by the return to normal offgas radiation levels. The inspector had no further questions.

7.0 Potentially Reportable Occurrences (PRO)

The inspectors reviewed the following potentially reportable occurrence (PRO) evaluation reports submitted to the engineering support department (ESD) since November 1, 1987, to ensure proper disposition with regard to procedure AP 0010, Revision 17, Occurrence Reports, consistent with the requirements of 10 CFR 50.73.

PRO 87-62, submitted November 13, 1987: RCIC turbine failed to trip. On November 9, 1987 the RCIC turbine failed to trip as required when the turbine was being secured. The RCIC had been operating to control reactor vessel level and pressure following the reactor scram the previous day. Trip throttle valve RCIC-1 failed to trip the turbine when actuated from control room panel (CRP) 9-4. Isolation valve V13-131 was closed to secure the turbine. The trip valve linkage was cleaned and lubricated and trip tested successfully two times from the CRP. The RCIC was full flow tested satisfactorily and declared operable. This event was considered as not reportable because failure of the trip throttle valve as described would not have prevented the RCIC system from fullfilling its design basis safety function. This PRO was approved by the plant manager on November 17, 1987.

PRO 87-63, submitted December 2, 1987: Loss of the nuclear alert system (NAS) telephone. On December 1, 1987 portions of the NAS telephone network were lost due to excessive line noise. Communications and notifications were maintained by use of conventional land line telephones. This event was considered as not reportable because a reliable communication link was maintained while the NAS telephone was out of service. This PRO was approved by the plant manager on December 7, 1987.

PRO 87-64, submitted December 2, 1987: Inadvertent trip of one train of the toxic gas monitoring system (TGM). On December 2, 1987, train A of the TGM system tripped as a result of personnel error in the performance of TGM surveillance procedure OP 4328, Revision 4. This event was considered as not reportable because only one train of a two train system was rendered inoperable. This PRO was approved by the plant manager on December 7, 1987.

8.0 Licensee Event Report Reviews

The following licensee event reports (LER) were reviewed by the inspectors to ensure that; the report was submitted in a timely manner; that description of the event presented was accurate; that root cause analysis was performed; safety implications were considered; and corrective actions implemented or planned are sufficient to preclude reccurrence of a similar event.

LER 271/87-17, Main Turbine Trip And Reactor Scram From Feedwater Valve Malfunction Due To Personnel Valve Repair Error. This LER was submitted as a result of the reactor scram of November 8, 1987. The event, root cause and corrective actions as described in the LER are documented in detail in section 9.1. The LER was submitted in a timely manner and adequately addressed the reporting criteria. The inspectors had no questions concerning this LER.

LER 271/87-18, RCIC System Inoperable Due To Damaged Turbine Exhaust Valve. This LER was submitted as a result of a failed RCIC flow surveillance test performed on November 14, 1987. The event, root cause analysis, and implemented and planned corrective actions as described in the LER are documented in detail in section 9.3. The LER was submitted in a timely manner and adequately addressed the reporting criteria. The inspectors had no questions concerning this LER.

9.0 Operational Event Reviews

9.1 Automatic Reactor Trip

On November 8, 1987, at 1:30 a.m., the reactor automatically scrammed from approximately 87% power. The reactor scrammed due to an automatic turbine trip on high reactor vessel water level.

Immediately following the trip a primary containment isolation system (PCIS) Group 1 isolation signal was received and automatically closed the main steam isolation valves due to high main steam line flow with the mode switch in Refuel.

Prior to the scram reactor power was in the process of being reduced from 100% to 80%. The down power evolution was required to facilitate routine weekly and monthly turbine and control rod drive system surveillance testing. The feedwater control system, which was in three element control, responded properly to the power reduction until reactor power decreased to approximately 90%. The reactor water level began to rise as power was reduced below 90%. Upon recognition of the increasing reactor water level, the control room operators took manual control of the feedwater control system and attempted to reduce the water level. The feedwater regulating valves failed to respond to manual mode operation and the reactor water level continued to rise until an automatic high reactor water level main turbine trip and subsequent reactor scram occurred at approximately 87% power.

The feedwater regulating valves (FRV) FCV-12A and B were unable to close in response to automatic signals or manual remote operator action because normal valve motion had been restricted. Several weeks earlier a FRV position mismatch had been observed. The threaded sleeve of the manual operator on FCV-12B had rotated from the neutral position down the valve stem and was preventing the valve from opening. Valve FCV-12A, which was functioning properly, continued to open to maintain reactor water level, creating the mismatch. The sleeve is normally fixed to the valve stem by a key and keyway preventing sleeve rotation. It was believed that the key was broken or missing on FCV-12B and an outstanding maintenance request (MR) existed for its repair.

Maintenance personnel rotated the sleeve on FCV-12B back up the valve stem and wired it to the valve yoke to prevent it from freely rotating downward again. At some time later, a member of the operations staff observed the temporary fix of FCV-12B and rotated the sleeve of FCV-12A and wired the valve to mirror FCV-12B, even though FCV-12A had been fully operable. However, the sleeve on FCV-12B had been rotated up the valve stem past the neutral position and was wired fixed in a position which prevented valve closure. The improperly positioned sleeves on both valves prevented valve closure causing the high reactor water level, turbine trip and reactor scram. The maintenance activity which repositioned the FCV-12B sleeve and installed the securing wire was considered an extension of the previously exisitng MR.

After receiving the automatic scram the operators executed the scram procedure OE 3100, revision 3. The procedure directs that the reactor mode switch be transferred from the Run position to the Refuel position when the steam flow in each main steam line is less than 0.64 mlbm/hr or 40% of rated flow (Transfer of the mode switch from the Run position at main steam line flows greater than 40% would cause the MSIV's to isolate on a high steam flow signal, which is a PCIS Group 1 isolation). When the operators verified steam flow to be less than 40% and placed the mode switch in Refuel a PCIS Group 1 isolation occurred. The subsequent MSIV closure caused a reactor pressure increase and resultant reactor water level decrease which initiated PCIS Groups 2,3 and 5. Reactor level recovered in 12 seconds and continued to increase until the reactor feedwater pumps tripped on high reactor water level. The Group 1 isolation was reset, the MSIVs were reopened and all systems were stabilized within two minutes of the event. During the event all systems operated as designed.

The PCIS Group 1 isolation occurred because the mode switch was transferred out of the Run position before the high steam line flow switches had reset. These switches trip at equal to or less than 40% steam flow but do not reset until steam flow has decreased to 5% less than the trip setpoint due to hysteresis and internal flow snubbers which delay the signal. The scram procedure did not recognize this condition and directed that the mode switch be transferred to Refuel when flow is less than exactly 40% power. Further, the actual trip setpoint was conservatively set for 38% steam flow not 40% as indicated in the scram procedure and as marked on the main steam line flow meters on main control room panel CRP 9-5. The reactor operators on shift, as well as most of the other licensed operators, were not aware of the 5% deadband or the value of the actual trip setpoint. The apparent training weakness was compounded by the fact that the plant specific training simulator does not reproduce the deadband in the switch reset.

The inspectors identified two areas of concern in review of this event. The first concern was that the maintenance on FRV B was performed under an MR generated because of possible hand actuator or key failures. It did not address the function or operation of the sleeve or the necessity to position the sleeve in the neutral position. Further, no post-maintenance test was prescribed to determine the effectiveness of the maintenance. The licensee is currently reviewing this concern with regard to generic weaknesses with the MR process.

The licensee has initiated actions to preclude recurrence of similar events. Special training in the operation of the FRVs will be given. The feedwater system operation procedure has been changed to ensure that the FRV sleeves be in the neutral position. The wiring on FRV B was replaced with a clamp and the valve was satisfactorily stroke tested. The FRV A was returned to its original configuration and was satisfactorily stroke tested. The FRV B will be inspected next refueling outage for final resolution of a permanent repair. Neutral FRV sleeve position will be verified by daily operator rounds.

The second concern was that immediately following the scram, and during initial event reviews, the licensee did not appear to address the PCIS Group 1 isolation. The licensee 10 CFR 50.72 notification to the NRC and initial post scram reviews did not identify the PCIS Group 1 isolation as an abnormal or unexpected ESF actuation in response to the scram. When questioned by the inspectors the licensee stated that the Group 1 isolation was in fact unexpected and preventable. The licensee identified procedural, training and operator aid deficiencies relating to the operation of the high steam line flow trip switches as the root cause for the isolation.

The licensee has implemented corrective actions to prevent recurrence of similar Group 1 isolations. The single line visual operator aid on the steam line flow meters at CRP 9-5 has been replaced with two lines, one at the actual trip setpoint and one at the corresponding trip reset point. An Operations Department memorandum, dated November 24, 1987 was issued describing the switch deadband and visual operator aid improvements. Scram procedure OE 3100 is being revised to instruct the operators to transfer the mode switch to Refuel when steam flow in each main steam line is less than 0.5 mlbm/hr or 30% of rated flow.

The inspectors had no further concerns regarding this event.

9.2 High Pressure Coolant Injecton System Operability

On November 5, 1987, the high pressure coolant injection (HPCI) system was declared inoperable when an operator noted that the system flow controller indicator was reading 400 gpm with the system secured. Technical Specification 4.5.E.1 requires that HPCI supply a minimum of 4250 gpm flow. With the flow controller in automatic and the flow indicator erroneously reading 400 gpm, automatic actuation of the system to maintain reactor water level would have resulted in a flow rate less than that required by Technical Specifications. Licensee investigation revealed that the indication error was caused by air trapped in the flow transmitter sensing line. The air caused a false differential pressure to be sensed by the transmitter resulting in an erroneous flow indication. The transmitter was subsequently vented, refilled, and returned to service. Subsequent HPCI system operability testing was performed satisfactorily including a flow rate test to verify system flow greater than 4250 gpm.

Licensee investigation determined that air had probably entered the transmitter sensing line during the last calibration procedure. This flow transmitter (GEMAC 555) is calibrated dry due to system configuration and must be refilled and vented upon completion of the procedure. In this case, apparently, the transmitter was improperly vented. The licensee attributes the improper venting to a procedure weakness. Inspector review of the applicable plant procedure (OP 5314, Calibration of HPCI System Balance of Plant Instrumentation) showed it to be a broad procedure covering dozens of instruments of all types, containing only general precautions and referencing the technician to applicable instrument technical literature. A more appropriate root cause determination by the licensee for this event should have been personnel error due to incomplete venting of the transmitter. Licensee corrective actions included specific caution notes in the plant procedure to stress the importance of thorough venting, verification of proper instrument reading after calibration is complete, and periodic observation during operation.

Inspector review of this event identified two areas of concern. First was the fact that a safety related control room instrument exhibited an abnormal indication most probably for two months without identification. Although HPCI flow indication was not on the control room operator rounds sheet, normal observation of control board indications and shift turnover control board walkdowns should have been sufficient to identify the erroneous indication. Additionally, HPCI operability tests were conducted twice in October and preparations for these tests should have identified the problem as well. The licensee has recently included this and other similar indicators on the control room operator rounds sheet. The second area of concern was that the flow transmitter was not recalibrated upon discovery of unvented air in the differential pressure (dP) cell. On November 5 technicians verified that the control room indication of 400 gpm was legitimately caused by a 12ma output from the transmitter. Under no flow conditions this output should be 10ma (and had indicated such during the August 27, 1987 calibration). Upon venting and refilling the dP cell, the reading returned to approximately 10ma. Technicians considered this satisfactory proof that the cell was still calibrated. Because of the two month time interval between initial calibration and identification of the error, a more prudent approach would have been to perform a complete recalibration of the instrument. Upon subsequent discussion with the inspector, the licensee determined that recalibration of the dP cell was appropriate. Licensee corrective actions were responsive to these concerns. The inspector will continue to monitor these areas during routine inspection activities to determine whether these were anomalous events.

9.3 Reactor Core Isolation Cooling System Operability

On November 14, 1987, during the scheduled monthly flow test surveillance of the reactor core isolation cooling (RCIC) system, the RCIC turbine tripped on high exhaust pressure. Repeated start attempts resulted in the same trip and RCIC was subsequently declared inoperable. Technical Specification 4.5.G.2 required alternate testing of the high pressure coolant injection (HPCI) system was performed satisfactorily in response to RCIC inoperability. Initial licensee investigation checked the exhaust pressure sensors, transmitters and trip device for proper operation. Satisfactory operation of these components led the licensee to believe a flow restriction may have been present in the RCIC turbine steam exhaust line. This line exhausts to the suppression pool. Two check valves in this line provide containment isolation. The first is a simple swing check, the second is a stop check. An industry history search revealed a number of instances of malfunctions of similar check valves. Based on this information, the licensee performed radiographic examinations of the two check valves to verify internal integrity and determine if flow restrictions existed in the valves. Results of the examination showed the downstream stop check valve, RCIC-9, to be intact with no flow restriction. However, the radiograph of the upstream swing check, RCIC-50, showed that the disc had separated from the swing arm and had lodged in the valve body. Licensee disassembly and inspection of the valve (8" Walworth Model #F16H534/WE) showed that the threaded stud which secures the disc to the swing arm had failed allowing the disc to disengage from the arm. The disc was found inverted and almost completely blocking the valve exit. Inspection found the valve body, swing arm, hinge pin and valve seat to be in good condition. The fractured portion of the stud along with the securing nut, washer and cotter pin were not recovered. Borescopic inspection of RCIC-9 showed that the missing pieces had not lodged in that valve nor was there any evidence of damage. The licensee believes these pieces were probably transported to the suppression pool and have settled there. Licensee analysis indicates that these pieces do not represent a hazard to equipment taking a suction on the suppression pool. A new disc, nut, washer and cotter pin were replaced and RCIC-50 was reassembled. A subsequent full flow retest of RCIC was satisfactory and the system was returned to operable status on November 18.

The licensee has attributed the root cause of this event to fatigue failure of the disc due to repeated contact with the disc travel stop on the valve cover. Significant contact occurs each time the RCIC system is started. This valve had no prior failure history and apparently was never disassembled and inspected prior to this failure. Current testing of this and several other functionally similar check valves is limited to verification of valve opening under the Inservice Testing (IST) program. The licensee plans to incorporate open-and-inspect requirements for this and similar valves in the IST program. Inspector review of this event determined that the licensee took an aggressive and well-engineered approach to problem identification and resolution. Licensee reviews and analysis were thorough. The RCIC system down time was minimized by a coordinated maintenance repair effort. The inspector had no further questions.

9.4 Notification Of Unusual Event

On December 15, 1987, at 12:30 a.m., train B standby diesel generator (SDG) DG-1-1B was removed from service to perform preventive maintenance not accomplished during the 1987 refueling outage. In accordance with the requirements of TS 3.5.H.1, alternate testing of train A SDG (DG-1-1A) and the train A and B low pressure core and containment cooling systems was commenced at 1:11 a.m. The A SDG operability run was completed satisfactorily at 2:27 a.m. At 4:12 a.m. the drywell spray motor operated discharge isolation valve RHR-26A failed to stroke due to a locked operator rotor and was declared inoperable. The T.S. 3.5.H.1 limiting condition for operation requires that an orderly shutdown be initiated and the reactor be in cold shutdown within twenty-four hours if the alternate testing criteria are not met. The licensee declared an Unusual Event as of 4:12 a.m. in accordance with procedure AP 3125, Revision 6, entitled Emergency Plan Classification and Action Level Scheme. Procedure AP 3125 requires an Unusual Event to be declared when the loss of a system function or engineered safety feature requires a plant shutdown in accordance with TS Limiting Conditions for Operation. All appropriate state and local notifications were made. The repair of valve RHR-26A is documented in detail in section 10.3.

Licensee management directed that in conjunction with repairing valve RHR-26A, the preventive maintenance being performed on the B SDG be suspended and the diesel returned to service as soon as possible.

The valve was repaired and successfully tested and declared operable at 1:30 p.m. The B SDG post maintenance operability run was started at 2:20 p.m. The Unusual Event was secured at 2:35 p.m. and the B SDG operability run was completed satisfactorily at 4:01 p.m.

The licensee responded prudently following the declaration of the Unusual Event. The B SDG was conservatively returned to service and the repair of valve RHR-26A was well coordinated. Good communication between plant disciplines was evident. The inspectors had no further questions concerning this event.

10.0 Review of Maintenance Activities

10.1 Significant Outage Maintenance

The following maintenance activities were accomplished during the two day outage following the November 8, 1987 reactor scram:

-- Fabrication, installation and post-maintenance test of the temporary clamp on FRV B (MR 87-1827) (LER 87-17).

-- Addition of packing to valve V13-15 inside primary containment (MR 87-2932).

-- Repacking of valve MS-83A (MR 87-2881).

-- Replacement of the cover gasket on high level switch LSH-143 in the steam tunnel (MR 87-2929).

-- Removal of main steam line B drain trap high level switch LSH-38B. Capped supply and discharge lines (MR 87-0320) (LL/J 87-0164).

-- Adjustments and repairs to the B feed pump lube oil system.

-- Cleaning and lubrication of trip throttle valve RCIC-1 (MR 87-2938) (PRO 87-62).

-- Inspection of Alterex coupling alignment (MR 87-2926).

The licensee accomplished a number of significant maintenance activities during the unplanned mini-outage following the November 8, 1987 reactor scram. This effort was a result of proper maintenance preplanning, prioritization, and rapid coordination and implementation of the short notice outage workforce.

10.2 Standby Diesel Generator A Maintenance

The SDG A was removed from service December 7-11, 1987 to perform preventive maintenance not accomplished during the 1987 refueling outage. The maintenance was performed in accordance with procedures OP 5223, Revision 6, entitled Emergency Diesel Generator Mainteannce and OP 5225, Revision 0, entitled Emergency Diesel Generator Electrical Maintenance.

Several instances of component wear were identified. The number 7 and 8 lower piston crankpin bearings were found to be scored and wiped and were replaced. The number 8 lower piston rod assembly was replaced as a result of damage incurred from the failed number 8 crankpin bearing. The excessive wear and eventual bearing wipe was caused by improper machining of the failed bearings which allowed misalignment and slight relative motion between the bearings and piston rods.

The number 6 and 7 cylinder fuel injector camshaft cams on the controller side camshaft had indications of wear on their leading edges. Increasing cam wear could retard fuel injection to the effected cylinders reducing the power output from these cylinders. The licensee has determined that complete failure of both cams to initiate fuel injection would not impair the operability of the SDG. Worst case failure of both cams would reduce diesel capacity by 1/12 (2 of 24 injectors failed) from 3000 KW to 2750 KW. The FSAR (Fig. 8.5.1) SDG design basis continuous load capacity of 2356 KW is less than the potential derated diesel capacity. Increasing cam wear can be observed by trending cylinder exhaust temperature readings. Maintenance memo dated December 9, 1987 requests that operations personnel record all SDG A cylinder exhaust temperatures every 30 minutes during one hour runs and every hour during eight hour runs. The camshafts on both SDG's are scheduled to be replaced next refueling outage.

The scavenging air blower lobe and casing clearances measurements were taken in accordance with Fairbanks Morse Service Information Letter dated November 15, 1984. All clearance readings were within specification for blowers inservice for more than one year.

The post-maintenance and operability runs were completed satisfactorily and SDG A was returned to service on the evening of December 11, 1987.

The maintenance on SDG A was performed in a well planned, efficient manner minimizing diesel generator unavailability and unit time in the TS LCO. No inadequacies were identified.

10.3 Valve RHR 26A Failure

On December 15, 1987, at 4:12 a.m., the drywell spray motor operated discharge isolation valve RHR-26A failed to stroke due to a locked operator rotor and was declared inoperable. The valve was being tested in accordance with the alternate testing requirements of TS 3.5.H.1, as the Standby Diesel Generat (SDG) B was out of service to perform preventive maintenance no ccomplished during the 1987 refueling outage. An Unussual Event declared and is documented in paragraph 9.4.

The licensee directed that in conjunction with the repair of valve RHR-26A SDG B maintenance be terminated and the diesel be returned to service expeditiously. The MR 87-3163 was generated for the repair of RHR-26A. Initial assessment of the failed valve indicated that the four bolts on the operator motor endbell had sheared off allowing rotor misalignment causing the rotor to lockup. The valve operator stroked normally when uncoupled from the motor, leading maintenance engineers to believe the failure mechanism involved only the motor.

The failed motor was manufactured by Reliance and was identified by frame number T56. It was replaced with a new, slightly heavier Reliance motor identified by frame number FZ56. The engineering support group performed a seismic evaluation and concluded that the 12.3 pound weight increase of the replacement motor did not adversely affect the seismic design criteria of the affected portions of the system. The MOVATS testing of the failed valve during the previous outage had revealed a non-regular two peak signature. The licensee had requested MOVATS vendor experts to evaluate the test data for valve reliability. The vendor subsequently recommended continued use of the motor operator with an increased inspection frequency. The licensee believes the second peak, which was observed when the valve was cycled open, may have been caused by slight free rotation of the motor for a very short distance due to excessive clearances within the motor. A motor hammer blow effect was experienced in conjunction with high torsional forces when the motor reached the end of the free travel and was sufficient in magnitude to shear the motor endbell bolts. Baseline MOVATS data on the new motor yielded a very traditional one peak signature.

The valve was successfully tested and declared operable at 1;30 p.m. The SDG B post maintenance operability run was started at ?:25 p.m. The Unusual Event was secured at 2:35 p.m. and the B SDG o ability run was completed satisfactorily at 4:01 p.m.

11.0 Review of Licensee Response to NRC Initiatives

11.1 NRC Bulletin 87-01 - Pipe Wall Thinning

Licensee responses and actions taken for NRC Bulletin 87-01, Thinning of Pipe Walls in Nuclear Power Plants, dated July 9, 1987, were reviewed to ensure that the information submitted responded to each requested action, was technically adequate and represented actions taken by the licensee.

Prior to issuance of IEB 87-01, two IE Notices, IEN 86-106 and IEN 86-106 Supplement I, were issued describing the event, probable causes and characteristics to consider for applicability relating to the Surry pipe rupture. The licensee has had a program in place for several years to monitor pipe wall thinning. The program and licensee actions taken as a result of IEN 86-106 are documented in inspection report 50-271/87-02, Paragraph 7.2.

The licensee responded to IEB 87-01, by correspondence FVY 87-94, dated September 11, 1987. The licensee addressed each requested action as required. The criteria used to identify condensate and feedwater piping sections potentially susceptible to erosion corrosion were: systems with carbon steel piping and fittings with diameter ten inches or greater, bulk fluid velocity greater than 10-12 ft/sec., fittings less than ten pipe diameters apart, systems with significant amounts of stored energy and temperature and pressure above the flashpoint of the liquid. Oxygen content was not considered in the selection process. The method of inspection was visual, where possible, by use of a high resolution internal moving camera and ultrasonic inspection for followup and inaccessible areas. The inspections were conducted during the 1987 refueling outage.

Initial inspection results revealed evidence of erosion corrosion in the feedwater system at the third elbow (45 degree) downstream of the C feedpump, on steam extraction lines inside the main condenser, and on the train A feedwater warm up line. The evaluation of the damage concluded that design wall thickness would not be compromised during the current operational cycle and personnel and equipment hazard would be unaffected. The final results are being formalized and will be submitted to the NRC in January 1988. No inadequacies were identified.

11.2 IE Bulletin 86-01 - RHR Pump Potential Failure Mode

The IE Bulletin 86-01, "Minimum Flow Logic Problems That Could Disable RHR Pumps", was issued to licensees of GE BWR facilities on May 23, 1986 to request those licensees to review the RHR system logic design to determine whether a problem identified at another facilty was applicable. The bulletin concerns the potential failure of a single flow instrument that could cause all four RHR pumps to become inoperable.

Inspector technical review of the potential failure mode determined that it was not applicable to VYNPS (see Inspection Report 50-271/86-10). Review of the licensee's response to IEB 86-01 shows that they also concluded that a single active failure of any one flow switch would not render all RHR pumps inoperable. The licensee's response was comprehensive, addressed the concern, and was submitted within the required seven day period. The inspector had no further questions on this item.

11.3 Region I Temporary Instruction 87-04, Bypass of Non-Essential Diesel Generator Trips

Region I TI 87-04, Bypass of Non-Essential Diesel Generator Trips, addresses a potentially generic issue wherein emergency diesel generator non-essential trips may not be bypassed as designed under loss of offsite power (LOOP) or loss of coolant accident (LOCA) scenarios.

The standby diesel generators (SDG) at VYNPS have five protective engine trips and two protective lockouts. The SDG's will automatically trip from rated speed upon receipt of; jacket cooling high temperature (205F), jacket cooling low pressure (10 psig), low lube oil pressure (16 psig), high crankcase pressure (0.5 in H_2O positive pressure) and engine overspeed (approximately 1000 rpm). The SDG's will automatically lock out and not start unless reset if engine speed is less than 250 rpm within 112 seconds of start signal. The generator will lockout and shutdown the diesel engine driver on reverse power, loss of field and generator phase differential.

The protective trips and lockouts above are not bypassed under any accident scenario at VYNPS. The 125 Vdc SDG protective trip circuits for SDG A are supplied normally by Bus DC-2AS, CKT 6 or alternately by Bus DC-2, CKT 22. The SDG B trip circuits are supplied normally by Bus DC-1 or alternately by DC-2. The protective trip circuitry is non-redundant. The 125 Vdc battery pilot cell specific gravity readings are measured weekly and full cell readings are measured quarterly.

No inadequacies were identified.

12.0 Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted pursuant to Technical Specifications were reviewed. This review verified that the reported information was valid and included the NRC required data; that test results and supporting information were consistent with design predictions and performance specifications; and that planned corrective actions were adequate for resolution of the problem. The inspector also ascertained whether any reported information should be classified as an abnormal occurrence. The following reports were reviewed:

-- Monthly Statistical Report for plant operations for the months of October and November, 1987.

The inspector noted no deficiencies.

13.0 Nuclear Safety Audit and Review Committee

The resident inspector attended a semi-annual nuclear safety audit and review committee (NSARC) meeting on November 19, 1987. Technical Specification 6.2.B requirements for board composition were met. NSARC topics included the following:

-- Previous meeting minutes

-- Outstanding action items

-- Plant activities status report with emphasis on recent reactor scrams, security events and problems concerning contaminated material found outside the radiological control area.

-- Licensing activites status report with emphasis on priority listing of currently proposed licensing changes, review of proposed Technical Specification Change No. 142, and review of generic issues.

-- Quality assurance activities status report including review of surveillances and audits accomplished, and status of the Vendor QA Task Force draft report.

-- Review of plant operations review committee (PORC) meeting minutes.
-- Review of recent Licensee Event Reports (LER's)

-- Review of engineering design change report (EDCR) safety evaluations, plant design change reports (PDCR's), plant alteration reports (PAR's) and NRC inspection reports.

-- Status of the compilation of Vermont Yankee design basis documentation into a readily retrievable data base.

-- Review of results of recent VYNPS pipe wall thinning investigations.

The inspector observed that the NSARC performed Technical Specification 6.2.B.5 and .6 required reviews at a level consistent with the safety significance of the issue. Discussions were consistently perceptive and professional. Active NSARC review and involvement in a wide variety of issues was evident. A questioning and probing attitude was maintained throughout the discussions. The inspector had no questions in this area.

14.0 Management Meetings

At periodic intervals during this inspection, meetings were held with senior plant management to discuss the findings. A summary of findings for the report period was also discussed at the conclusion of the inspection and prior to report issuance. No proprietary information was identified as being included in the report.