U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 85-20

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

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

Facility Name: Vermont Yankee Nuclear Power Station

Inspection at: Vernon, Vermont

Inspection Conducted: June 4 - July 1, 1985

Inspectors: William J. Raymond 7/29/85
W. J. Raymond, Senior Resident Inspector date

for J. E. Tripp 8/2/85
G. W. Meyer, Projects Engineer date

for J. E. Tripp 8/2/85
F. A. Casella, Reactor Engineer date

Approved by: J. E. Tripp 8/2/85
L. E. Tripp, Chief, Reactor Projects date
Section 3A, Projects Branch 3

Inspection Summary: Inspection Conducted June 4 - July 1, 1985 (Report No. 50-271/84-20)
Areas Inspected: Routine, unannounced inspection on day time and backshifts by resident and regional inspectors of: actions on previous inspection findings; plant physical security; spent fuel pool design design review; followup of events; maintenance activities; surveillance activities; review of emergency communications equipment; review the adequacy of procedures and controls to preclude an overpressurization event; review of actions on selected safety issues; review of strike contingency plans; and, review of actions to correct deficiencies in document control procedures. The inspection involved 177 hours.

Results: No violations were identified in 12 areas inspected. Operational status reviews identified no conditions adverse to safe operation of the facility. A licensee identified violation is discussed in section 13.

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DETAILS

1. Persons Contacted

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

Mr. P. Donnelly, Acting Technical Services Superintendent
Ms. C. Faulkner, Document Control Coordinator
Mr. R. Lopriore, Maintenance Supervisor
Mr. D. Reid, Operations Superintendent
Mr. J. Pelletier, Plant Manager

2. Status of Previous Inspection Findings

2.1 (Closed) Follow Item 84-08-05: Control of Acetone. During a previous receipt inspection of new fuel bundles, acetone was utilized which was contaminated with acetic acid. The licensee determined that no adverse effects had occurred, but committed to upgrade controls of acetone used for new fuel receipt inspections. The inspector reviewed procedure OP 1401, New Fuel Inspection and Channeling, Revision 12, which was revised to include Attachment III, Acetone Control Check-sheet, and to upgrade administrative controls of acetone. Also, the inspector reviewed procedure AP 0620, Chemical Material Control, Revision 1, which contained consistent guidance on the control of acetone. The inspector concluded that the corrective actions were thorough and should prevent future acetone control problems. This item is closed.

2.2 (Open) Violation 84-21-07: Bolting of Shroud Head to Reactor. Licensee letter FVY 85-02 dated January 14, 1985, stated that OP 1201 was revised to require a briefing on the vessel equipment and tools, to provide more detailed bolt tightening instructions, and to specify an underwater inspection of post-work parameters.

However, the inspector reviewed OP 1201 and found no evidence of the procedure changes. In discussions with the inspector, the maintenance supervisor stated that the last reactor assembly had been performed using OP 1201 with Department Instruction (DI) 84-13, which implemented the above changes. Although the DI was designated as a one-time instruction and subsequently expired, the supervisor stated that a PORC Open Item is being used to track the final revision of OP 1201 to implement the above commitments and to incorporate any additional changes which result from the ongoing overall review of the procedure. The supervisor stated that OP 1201 would be revised prior to the next reactor assembly, following the outage beginning in September, 1985. This item remains open pending final revision of OP 1201 and subsequent NRC review.

2.3 (Closed) Violation 84-20-01: Loss of Secondary Containment Integrity. On July 17, 1984, secondary containment integrity was compromised due to work in the service water system in the reactor building. Licensee letter FVY 84-134 dated November 9, 1984 responded to the violation and documented the corrective actions taken and planned. The immediate corrective actions were reviewed in Report

50-271/84-20. The additional corrective actions included additional training of contractors in administrative procedures, revisions to administrative procedures, and reemphasis to plant personnel of the importance of following procedures.

The inspector reviewed records of additional training provided to contractor personnel on administrative procedures. The training was adjusted according to the procedures applicable to the job function. The training involved over 16 contractors and was completed by May 31, 1985.

The inspector reviewed procedures AP 0020, Temporary Electrical Jumpers, Lifted Leads and Mechanical Bypasses, Revision 8, and AP 0140, Vermont Yankee Local Control Switching Rules, Revision 8, to verify that the committed revisions had been implemented. The changes had been incorporated and were acceptable.

The inspector witnessed portions of plant management's briefing of plant personnel on the importance of following procedures and interviewed other plant personnel to confirm that other briefings had been performed. This item is closed.

2.4 (Closed) Violation 84-20-02: Failure to Follow Plant Procedures. The failure to follow plant administrative procedures for tagging resulted in the above loss of secondary containment integrity. The corrective actions were discussed as part of Violation 84-20-01 and are acceptable. This item is closed.

2.5 (Closed) Violation 84-20-03: Failure to complete a Safety Evaluation. This violation was rescinded by NRC letter dated October 11, 1984. This item is closed.

2.6 (Closed) Unresolved Item 84-20-04: Submittal of a Licensee Event Report (LER) for Violation 84-20-01. The licensee submitted LER 84-12 concerning violation 84-20-01, Loss of Secondary Containment Integrity. LER 84-12 was reviewed in Inspection Report 50-271/84-18. This item is closed.

2.7 (Closed) Follow Item 84-20-05: Additional Review of Offsite Dose Calculations. The calculation of potential offsite dose due to the above loss of secondary containment integrity was reviewed further prior to transmittal of the Notice of Violation on October 11, 1984. Results were acceptable, and no additional actions are warranted. This item is closed.

2.8 (Open) Unresolved Item 85-18-05: Conax Penetration Assemblies. The licensee submitted a report under 10 CFR Part 21 dated June 19, 1985 to notify the NRC that a defect may exist regarding Conax Penetration assemblies with teflon seals. Although the use of Conax penetrations at Vermont Yankee would not result in a substantial safety hazard, a problem may exist at other plants using the assemblies. The inspector had no further comment regarding the reportability of the item.

This item remains open pending completion of a review by the NRC of the licensee's engineering review to identify the locations of the Conax assemblies installed at the plant.

2.9 (Open) Unresolved Item 85-10-04: Licensee Assessment of Operator Readiness to Implement New Emergency Operating Procedures. The inspector interviewed additional licensed operators regarding their confidence in using the new symptom based emergency operating procedures (OEs). Refer to Section 8 of Inspection Report 85-18 for additional interview results. The overall results from all interviews confirmed the initial conclusion that a majority of operations personnel desired additional training on the OEs prior to implementation.

Based on discussions with the NRC staff on May 30, 1985, the licensee completed a detailed interview of each operator regarding his readiness to use the procedures. The inspector witnessed a portion of the interviews and attended the meeting on June 14, 1985 when the survey results were reviewed by plant management. Seventy two percent of those interviewed by the licensee stated that they believed they could exercise their licensed duties in using the new OEs, but they were not confident or comfortable in using the procedures due to insufficient training. Seventy eight percent of those interviewed stated, without reservation, that at least 5 more days of simulator training using the Dresden simulator, if necessary, along with more classroom reviews and scenario study was desirable.

Based on the survey results, the licensee deferred implementation of the new OEs pending the completion of the desired training. Arrangements were made for all six crews to attend a 5 day OE training session at the Dresden simulator. The sessions began in July, 1985 and will be completed in early October, 1985. The training includes classroom reviews, and additional coverage of the off normal and operational transient procedures. The licensee will re-interview each crew as the training is completed regarding their readiness to use the procedures. The procedures would then be implemented, consistent with the above, subsequent to the plant shutdown for the recirculation pipe replacement outage that begins in September, 1985.

This item will be reviewed further on a subsequent inspection pending completion of the additional training, and pending NRC review of the licensee's survey of operator readiness to implement the OEs.

2.10 (Closed) Unresolved Item 85-14-04: Followup Improper Isolation Valve Logic Test. The inspector reviewed 9 additional logic tests for safety related systems for the period of 1984-1985. No other discrepancies were identified similar to that noted in OP 4334.

Based on discussions with the I&C Engineering Assistant on June 17, 1985, the inspector noted that OP 4334 was performed incorrectly in 1981 and 1983. The procedure error was identified and corrected during the 1984 test and the isolation logic for valves V72-38A&B was properly tested at that time. OP 4334 is scheduled for revision prior to the next performance of the test. Additionally, the isolation logic was also tested in 1981 and 1983 through the satisfactory completion of OP 4332 and 4333 on the Standby Gas Treatment System. The inspector verified by review of the test procedures and control wiring diagram 191301, sheet 1116 that OP 4332 and OP 4333 provide for a proper test of the trip logic for valves V72-38A&B.

The inspector noted that procedure OP 4334 was changed in Revision 6 to list valves V72-38A&B as normally closed due to modifications completed under PAR 80-3. When PAR 80-34 was implemented in the same year, OP 4334 was not revised a second time

to list the valves as normally open and to reinstate a test for the PCIS Group 3 isolation signal to the valves. The inspector noted further that the licensee has a program in progress to upgrade the format of the safety system logic test procedures. The improved format will make it easier to detect discrepancies of the type noted in OP 4334 for the 1981 and 1983 tests. The revisions will be completed as the procedures come due for the biennial review cycle.

The discrepancy associated with OP 4334 appears to be an isolated case in view of the large number of surveillance procedures potentially affected by plant modifications and appears to have stemmed from the unusual circumstance where the normal position of two valves was changed twice by modifications in one year.

Licensee control of surveillance procedure changes following plant modifications was addressed in violation 85-08-01 and the corrective actions for that item are in progress. The control of procedures following design changes will be reviewed during followup of item 85-08-01 on subsequent inspections. Inspection item 85-14-04 is closed.

2.11 (Closed) Unresolved Item 85-18-02: Diesel Generator Part 21 Report. The licensee determined that the concerns identified in the Louis Allis Part 21 Report dated May 29, 1985 were applicable to the Fairbanks Morse emergency diesel generators. Actions were completed during this inspection to correct the problem, as discussed in Section 10.0 below. This item is closed.

3.0 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; random observations of the secondary alarm station; verification of physical barrier integrity in the protected and vital areas; verification that isolation zones were maintained; and implementation of access controls, including identification, authorization, badging, escorting, personnel and vehicle searches. The inspector also reviewed the actions taken by security personnel following an Unusual Event that was declared on June 20, 1985. No inadequacies were identified.

4.0 Shift Logs and Operating Records

Shift logs and operating records were reviewed periodically to determine the status of the plant and changes in operational conditions since the last log review, and to verify that: (1) selected Technical Specification limits were met; (2) log entries involving abnormal conditions provided sufficient detail to communicate equipment status, correction, and restoration; (3) operating logs and surveillance sheets were properly completed and log book reviews were conducted by the staff; (4) potential reportable occurrences were filed as licensee event reports when required; and, (5) Operating and Special Orders did not conflict with Technical Specification requirements.

The licensee's evaluation for PRO 85-18 was reviewed on June 7, 1985 regarding the failure of relay 16A-K16 for the MSIV AC solenoids. The item was found to be not reportable.

No discrepancies were identified

5.0 Spent Fuel Pool (SFP) Design Review

The spent fuel pool was reviewed to determine the potential for uncovering spent fuel assuming a break in any of the attached piping. It was concluded that the combination of design features and administrative controls are sufficient to preclude uncovering fuel and creating a safety hazard. The systems features that support this conclusion are discussed below.

5.1 Design Features

5.1.1 Normal Level and Instrumentation. - The bottom of the spent fuel pool is at elevation 306 ft. The top of the spent fuel was assumed to be about 14 feet above the bottom of the pool, or at 320 ft. Normal water level in the pool is at about 343 ft. Level instrumentation monitors the water level in the pool and causes an annunciator to alarm in the main control room when level is less than normal. The 9 process lines that penetrate the spent fuel pool are described below. The lines described in items 5.1.3, 5.1.4, and 5.1.5 below meet seismic Category 1 requirements at the point of connection to the spent fuel pool.

5.1.2 Fuel Pool Skimmer System. - There are two 3 inch diameter discharge lines and two 2 inch diameter suction lines from the fuel pool skimmer pumps, which penetrate the pool liner close to the normal water level line. The lines drop down to the 318 ft. elevation to enter the skimmer pumps. A break in these lines at any location could not drain the pool below the normal water level.

5.1.3 Fuel Pool Cooling System Suction Lines. - Two 8 inch diameter lines penetrate the pool liner at the 336 ft. elevation and then join together at about the 330 ft. elevation prior to splitting again to enter the fuel pool cooling pumps. The lines penetrate the pool about 16 feet above the top of the fuel, and thus no break in any location in these lines could uncover the spent fuel. A normally open manual isolation valve, V19-11, could be closed by the operator for a break downstream of the valve.

5.1.4 Spent Fuel Pool Maintenance Line. - One 8 inch diameter pool maintenance line takes suction from the sump at the bottom of the pool. The pipe rises vertically from the sump to a penetration in the pool liner at the 334 ft. elevation, or 14 feet above the top of the fuel. A siphon break is located on the line inside the pool at the 334 ft. elevation. There are two normally closed manual valves on the line after it penetrates the liner. The first valve, V19-39, is located as close as possible to the shield wall at about 333 ft. The valve is normally locked closed. A second normally closed valve in series with the first is located in the 303 ft. elevation where the line joins the suction piping to the fuel pool cooling pumps. The combination of administrative controls and the siphon make it incredible that the pool would be drained through the maintenance line.

5.1.5 Fuel Pool Cooling Discharge Lines. - An 8 inch diameter line from the spent fuel cooling pumps rises to the 343 ft. elevation where the line splits into two headers which pass through a valve pit prior to penetrating the pool. There is a normally open manual valve and a series check valve on each header. Each header then drops to a distribution sparger located on the bottom of the pool at the 306 ft. elevation.

A break in either header at the valves or downstream of the valves (pool side) cannot drain the pool below normal water level. A break in either header or the common supply line upstream of the manual valves (pump side) could not drain the pool unless the line break was accompanied by a failure in the check valve. In this case, the operator could shut the manual valve in response to an alarm on decreasing fuel pool water level and stop the drainage prior to fuel uncovery. The check valves are held open by the normal operation of the fuel pool cooling system. There are no tests or checks currently performed by the licensee to verify the leak tightness of the check valves. The only practical check of the valves would involve periodic disassembly and inspection of the check valve internals.

5.2 Conclusions

The inspector's concern regarding the need to periodically inspect and verify the leak tightness of the SFP cooling system discharge check valves (V19-21A&B) was discussed with licensee personnel. This matter will be reviewed further on a subsequent inspection pending completion of the licensee's review of the item (UNR 85-20-01).

The inspector walked down portions of the spent fuel pool cooling system and verified that the system valve lineup and controls were in accordance with procedure OP 2184 and Drawing G191173. Based on the above, a loss of spent fuel cooling based on a break in the fuel pool cooling system attached piping is not considered credible. No inadequacies were identified.

6.0 Inspection Tours

Plant tours were conducted during the inspection period to observe activities in progress and verify compliance with administrative requirements. Systems and equipment in areas toured were observed for fluid leaks and abnormal vibrations, and pipe snubbers and restraints were observed for proper conditions. Plant housekeeping conditions were observed for conformance with AP 0042, Plant Fire Prevention, and AP 6024, Plant Housekeeping. Inspection reviews and findings were as described below.

6.1 The inspector reviewed feedwater sprager leakage detection system and the monthly performance summary provided by the licensee in accordance with letter FVY 82-105. The licensee reported that based on the leakage monitoring data reduced as of May, 1985, there were no deviations in excess of 0.10 from the steady state value of normalized thermocouple readings, and no failures in the 16 thermocouples initially installed on the 4 feedwater nozzles. No unacceptable conditions were identified.

6.2 The status of the Residual Heat Removal, Residual Heat Removal Service Water, Service Water, High Pressure Coolant Injection, Core Spray, Standby Liquid Control and Reactor Core Isolation Cooling (RCIC) systems was reviewed to verify that the systems were properly aligned and fully operational in the standby mode. The review included the following: (1) verification that each accessible, major flow path valve was correctly positioned; (2) verification that power supplies and electrical breakers were properly aligned for active components; and, (3) visual inspection of major components for leakage, proper lubrication, cooling water supply, and general condition. No discrepancies were noted.

Additionally, the major flow path valves for the RHR system was compared with the lineup prescribed in OP 2124 and drawing G191172. A complete walkdown of the Containment Atmosphere Dilution (CAD) System was completed and compared to OP 2125 and drawing VY-E-75-002. No inadequacies were identified.

6.3 Radiation controls established by the licensee, including radiological surveys, condition of access control barriers, and postings within the radiation controlled area were observed for conformance with the requirements of 10 CFR 20 and AP 0503.

The inspector noted a small amount of uncontained leakage from the North bank of HCUs that drained into a nearby floor drain. There was a considerable buildup of residue on the floor which may have had concentrated radioactivity. The inspector questioned health physics personnel on June 12, 1985 regarding surveys for the leakage due to concerns for the potential for airborne activity. The leakage was from an HCU accumulator and contained water from the condensate storage tank (CST). The leakage had started on May 17, 1985 and the area containing the leakage was roped off at the time to prevent personnel traffic in the slightly contaminated water. The CST activity at the time was 1.0XE-5 uCi/ml and smears of the residue around the leakage showed contamination levels of about 1000 dpm/100 sq cm. Weekly general area air samples showed no abnormal air activity levels. The inspector's observations were discussed with a health physics supervisor who stated he would review the item. The inspector noted that the leakage was subsequently stopped and the area was cleaned up. No inadequacies were identified.

6.4 The control of equipment released from service was reviewed during the inspection to verify the equipment was controlled in accordance with AP 0140, VY Local Control Switching Rule. Work conducted under Switching and Tagging Orders 85-359 and 85-360 were reviewed and no discrepancies were noted.

7.0 Operational Status Reviews

The operational status of emergency and power generation systems was confirmed by direct review of control room instrumentation. Control room panels and operating logs were reviewed for indications of operational problems. Operational status reviews were performed to verify conformance with the Technical Specifications and approved procedures. Control room staffing and protocol were reviewed to assure manning requirements were met and acceptable working conditions were maintained. Licensed personnel were interviewed regarding existing plant conditions and

knowledge of recent changes to the plant and procedures, as applicable. Acknowledged alarms were reviewed with licensed personnel as to cause and corrective actions being taken, where applicable, and anomalous conditions were reviewed further. Inspection findings were as described below.

7.1 The licensee informed the inspector on June 7, 1985 that nonconformance report (NCR) 85-17 was initiated in accordance with the Environmental Qualification (EQ) Manual to address a problem with the local power range monitor (LPRM) channels. The EQ program did not identify the LPRM cables outside the primary containment as being subject to a harsh environment following a high energy line break (HELB). Thus, the LPRM cables were not categorized for qualification requirements, and no documentation existed to support the qualification of the cables. The LPRM cables were manufactured by Times Inc., and would be subject to a harsh environment following an HELB since they pass through the reactor building in cable trays.

The licensee dispositioned the NCR in accordance with the EQ Manual and his submittal to the NRC (FVY 85-20) dated May 3, 1985. Justification for continued operation (JCO) #39A was prepared within 7 days which concluded plant operation was justified until the refueling outage when the cables will be replaced.

The inspector reviewed JCO #39A and noted the LPRM cables provide signals to the RPS to scram the reactor on high neutron flux, and they provide neutron monitoring indication to verify reactor shutdown conditions. For a LOCA, the detectors complete their safety function prior to the development of a harsh environment.

If the cables were to fail during the HELB, reactor shutdown could be verified by the control rod position indication (RPI) system. The licensee considers the RPI system to be qualified for harsh environments, even though it is not in the EQ program, by reason of the similarity between the RPI cables and components with other electrical systems that have a fully acceptable QDR.

The RPS high and high-high neutron scrams could be affected by failures in the cables. For a HELB outside the drywell, the detectors are not required to mitigate the event or to achieve and maintain hot shutdown. In the event the detectors were made inoperable as a result of the HELB, the RPS would be declared inoperable and the reactor would be shutdown within 6 hours.

The inspector notes that the NRR staff has already approved an exemption (JCO #39) for qualification of the LPRMs until November 30, 1985. This item is considered open pending completion of licensee actions prior to startup from the 1985-86 outage to replace or otherwise qualify the LPRM cables inside the reactor building (UNR 85-20-02).

7.2 A ground occurred on the negative leg of the 'B' station battery on June 10, 1985. Licensee attempts to locate the ground per OP 2145 were not successful and the condition persisted throughout the inspection period. The battery remained fully operable. This item will be followed on subsequent inspections to review the status of the 'B' battery and to review licensee corrective actions to clear the ground condition (IFI 85-20-03).

7.3 The recirculation system leakage detection system (LDS) became inoperable during the inspection period and status information from the detectors was lost. Licensee attempts to repair the system were not successful. No change occurred in the drywell leak rates measured by the drywell floor and equipment drain systems. Continued operation without the LDS is acceptable. The leakage collected by the drywell sumps will be reviewed during future routine inspections. No inadequacies were identified.

8.0 Review of Plant Events

The inspector reviewed events that occurred during the inspection to verify continued safe operation of the reactor in accordance with the Technical Specifications and regulatory requirements. The following items, as applicable, were considered during the inspector's review of operational events: description of event, including cause, systems involved, safety significance, facility status, and response of safety systems; operational parameters were verified to remain within approved limits; details relating to release of radioactive material; verification of correct operation of automatic equipment, based on a review of the plant computer post-trip logs, as applicable; verification of proper manual actions by plant personnel and adherence to approved operating and emergency procedures; and, notification to the NRC and offsite agencies per 10 CFR 50.72.

8.1 Loss of Primary Containment

A trouble alarm was received in the control room at 10:40 A.M. on June 6, 1985 on the drywell atmosphere System II hydrogen-oxygen analyzer. A maintenance request was processed to investigate an apparent problem with the sample pump. While troubleshooting the problem at about 1:05 P.M., technicians discovered a broken suction line at a 90 degree elbow to the sample pump. Isolation valves were closed at about 1:10 P.M. to stop leakage of drywell atmosphere into the Reactor Building through the 1/4 inch, Type 316 stainless steel sample line. Plant operators declared an Unusual Event - Terminated at 1:29 P.M. based on an assumed loss of primary containment integrity during the period prior to isolating the sample system.

Plant operators isolated the containment air monitoring systems by closing all sample system isolation valves at 1:55 P.M. to assure the primary containment integrity requirements of Technical Specification 3.7.A.2 were met. Drywell equipment and floor drain leakage collection systems were operable to allow for continued plant operation for 7 days until the drywell air monitoring systems are returned to service. The inspector verified proper actions were taken to meet the LCO requirements until the systems were returned to normal.

Notifications were made to the NRC Duty Officer at 2:10 P.M. per 10 CFR 50.72, and to the offsite emergency response authorities in accordance with the emergency plan.

The sample line failed due to fatigue stress at the elbow. The sample lines for analyzer System II was replaced using slightly thicker walled tubing (35 mil vs 28 mil) after completion of an evaluation to assure no change in functional

requirements would occur. The routing of the tubing was also modified slightly to eliminate the 90 degree bend at the pump. The sample lines on the System I analyzer were also replaced as a preventive measure.

The licensee reported this event per 10 CFR 50.73 as LER 85-06. The inspector reviewed the LER and verified that it accurately described the event and corrective actions. No inadequacies were identified.

8.2 Aircraft Overflight

An Unusual Event - Terminated was declared at 1:05 A.M. on June 20, 1985 due to unusual aircraft activity over the site. Plant security noted a small plane flying over the site at 12:10 A.M. The plane circled the site 5 times and made one pass over the reactor building at an altitude that was judged to be over the height of the plant stack, which is 308 feet high. It was too dark to identify the type of plane or its markings.

The Federal Aviation Administration (FAA) was contacted for assistance in identifying the plane. The FAA tracked the plane for a short distance as it flew East from the site, but subsequently lost the plane when a radar installation was taken out of service for scheduled maintenance. There are no FAA restrictions regarding aircraft overflights above 500 feet.

Nothing was observed to have been dropped from the plane. A search was made between 1:30 and 2:30 A.M. of the protected area, the accessible building rooftops and portions of the owner controlled area. Nothing unusual was identified.

The NRC Duty Officer was notified of the event at 1:05 A.M. Notifications were also made to State authorities. No inadequacies were identified regarding the response to the event.

During a review of the actions taken per the emergency plan, the inspector noted that of 17 plant staff members who were 'paged' as part of the emergency response organization, only 5 people initially responded. At least 3 of the 17 people were not available. It appeared that as many as 9 of the 17 people paged either did not hear or receive the beeper notification. Twelve individuals were subsequently contacted by direct calls, which included primary and backup contacts amongst the various departments. This matter was discussed with the Emergency Plan Coordinator on June 20, 1985. This item is considered open pending completion of a licensee evaluation of the pager effectiveness for the June 20, 1985 notifications, and subsequent review by the NRC (UNR 85-20-04).

9.0 Surveillance Activities

9.1 Routine Surveillance Testing

The inspector reviewed portions of the surveillance tests listed below to verify that testing was performed in accordance with administrative requirements. The review included consideration of the following: procedures technically adequate;

testing performed by qualified personnel; test data demonstrated conformance with Technical Specification requirements; test data anomalies appropriately resolved; surveillance schedules met; test results reviewed and approved by supervisory personnel; and, proper restoration of systems to service.

+ OPF 4123.02, Core Spray MOV Operability Test, 6/25/85
+ OPF 4124.06, RHRSW Pump & Valve Operability Test, 6/25/85
+ OPF 4123.01, Core Spray System Full Flow Test, 6/25/85
+ OPF 4124.04, RHR Pump Operability Data Sheet, 6/25/85
+ OPF 4126.03, Diesel Generator Operational Readiness Demonstration, 6/25/85
+ OPF 4126.02, Diesel Generator Operability Data 6/26/85
+ OP 5223, Diesel Generator Maintenance - Meggar Tests, 6/27/85

No inadequacies were identified regarding testing for the routine surveillance program and post maintenance testing.

9.2 Special Surveillance Tests

During discussions with Vermont State officials, the licensee agreed to perform additional technical specification surveillance tests during the period from April 28 to May 2, 1985. The specific surveillance tests were listed in Attachment I to Inspection Report 50-271/84-14. The tests were not used to meet the technical specification minimum testing requirements. By letter dated June 14, 1985 from NRC Region I to the Governor of Vermont, the NRC agreed to perform an independent review of the test results.

The inspector reviewed the test results from all tests to verify that the test results met the established acceptance criteria. The inspector found that, with one exception, all test results were acceptable. The exception concerned the calibration test of the stack gas radiation monitors under surveillance test 4382. In step 16, the recorder for channel I of the stack gas radiation monitor did not meet the acceptance criteria of 2 percent accuracy as it indicated 900,000 counts per minute (cpm) when the input signal was 1,000,000 cpm. The radiation monitor recorder did meet the acceptance criteria at the 100,000 cpm and 10,000 cpm levels. Further, the deviation from the acceptance criteria had gone undetected by the licensee.

A licensee representative stated that this portion of the calibration would be repeated on the recorder for stack gas radiation monitor, channel I. Further, he stated that testing and review personnel would be reinstructed to ensure that all test results meet the acceptance criteria.

The stack gas radiation monitor channel I calibration was performed acceptably following replacement of the indicator display per Maintenance Request 85-1336. The channel meter was replaced because its output response was found nonlinear, which occurs due to mechanical wear with age. The channel recorder was satisfactorily tested following adjustment. The meter was last replaced about 10 years ago. There is no relation between the meter problem and receipt inspection practices. The test results were reviewed by the inspector and no discrepancies were noted.

In followup on this matter subsequent to the inspection, the inspector determined that there was a similar problem with the surveillance test run on February 4, 1985 for this recorder. The failure of the licensee to properly respond to surveillance test results that do not meet acceptance criteria will be followed up on in a subsequent inspection (Unresolved Item 85-20-10).

10.0 Maintenance Activities

The maintenance request log was reviewed to determine the scope and nature of work done on safety related equipment. The review confirmed: the repair of safety related equipment received priority attention; Technical Specification limiting conditions for operation (LCOs) were met while components were out of service; and, performance of alternate safety related systems was not impaired.

Maintenance activity associated with the following was reviewed to verify (where applicable) procedure compliance and equipment return to service, including operability testing.

+ MR 85-1040, System II H2O2 Analyzer Pump Tubing Failure
+ MR 85-1045, System I H2O2 Analyzer Inspection and Repair
+ MR 85-1107, Diesel Generator Amortisseur Dampeners
+ MR 85-1082, RCIC Valve V13-18 Motor Operator Ground

No inadequacies were identified. The following item warranted inspector followup.

10.1 Licensee inspection of the Fairbank Morse emergency diesel generators on June 4, 1985 revealed that both generators had pole piece connecting bars of the type that failed at the Calvert Cliff facility on May 14, 1985. The licensee contacted the generator vendor and evaluated the problem to formulate a corrective action plan, including the development of a repair procedure under OP 6023 to remove the interconnecting straps on the Amourtisseur dampeners.

The repair procedure contained an adequately approved safety evaluation to demonstrate that removal of the straps would not create an unreviewed safety question. The inspector reviewed the repair procedure and verified it contained adequate instructions to cut the straps as close to the pole pieces as possible. The procedure also specified appropriate controls to assure filings would not become lodged in the generator windings.

The licensee finished removal of the interpole connecting straps on both diesel generators by June 27, 1985. The inspector observed work activities in progress on each generator and the results of the megger tests that were completed prior to returning each diesel to service. The inspector noted that QC inspection for the work activity was provided by a worker who was independent of the job.

No problems were identified. Each diesel subsequently completed an operability demonstration prior to being returned to service. All 32 straps were sent offsite for radiographic examination for the presence of cracks. The examination results will be reported to the licensee at a later date. This item is open pending completion of the NDE on the straps and subsequent review by the NRC (IFI 85-20-05).

11.0 Review of Testable Check Valves on ESF Systems

A special inspection was completed to evaluate the adequacy of administrative controls and plant systems design features for preventing an interfacing loss of coolant accident (LOCA). The detailed results from this review were provided to NRC Region I for additional staff review and followup.

11.1 Design Features - The following systems contain components with design pressures less than 70% of the pressure of the primary coolant system: LPCI, SDC-RHR, CS, HPCI and RCIC. RCIC was included in the review even though it is not an ECCS system, since it met the selection criteria and operational experience with leakage past the 'testable' check valve has been a problem. Component lineups for these systems were developed using the format and nomenclature presented in NUREG/CR-2069. Motor operated valves that serve as "isolation valves" for the high-low pressure interface were identified and selected for review.

There are now no 'testable' check valves installed at the plant. The original plant design included the following air operated, testable check valves: RCIC - V22; HPCI - V18; CS - V13 A&B; RHR - V46 A&B. The injection check valves in the RCIC, HPCI and CS systems are Rockwell 970 JMMNY tilting disc check valves. The valves in the RHR system are an Atwood and Morrill tilting disc check valve. The air operators and position indicator circuits were removed in 1976 via a plant design change due to operational problems associated with unreliable position indication and unreliable valve operation. The valves operate as regular check valves in the present configuration.

The normal operational lineup for the CS, HPCI and RCIC systems consists of a normally closed check valve; a normally closed MOV: and, a normally open MOV. The lineup for the LPCI system is the same as the above, except that the MOV nearest the check valve is the normally open valve. The normal operational lineup for the SDC mode of RHR consists of two normally closed MOVs.

The LPCI, CS and SDC system valves are interlocked to prevent concurrent opening of the series isolation valves when reactor pressure is above preset limits. This design feature assures low pressure piping will not be overpressurized. The interlocks are not bypassed or defeated during routine operations.

Pressure transmitters and switches located on the LPCI, SDC, CS, HPCI and RCIC low pressure piping provide either indication or annunciation in the main control room which can alert the operator to excessive pressures so that timely corrective actions can be taken. For the LPCI, CS, RCIC and HPCI systems, the operator can close the second series MOV from the control room to protect the low pressure piping. For seat leakage past both normally closed SDC system valves, actions can be taken in the reactor building to vent the piping manually while the plant is taken to cold shutdown.

Plant operators have detected seat leakage past the check valves and MOVs in the HPCI, CS and RCIC systems. Leakage was detected during normal shift checks using the pressure instrumentation available in the control room. Leakage past the check valve and MOV in the B core spray loop was detected based on local pressure

indication in the ECCS corner room. Actions were taken in each instance in a timely manner to relieve pressure buildup prior to damaging the low pressure piping. The above examples illustrate that the combination of design features and operational experience is sufficient to preclude an overpressurization.

11.2 Surveillance Procedures and Testing - Surveillance procedures (and other references) applicable to the check valves and MOVs that provide isolation at the high-low pressure interface were identified and reviewed. The check valves are tested under the Inservice Test program. The MOVs are tested as part of the technical specification operational surveillance program. The testing requirements and precautions that preclude an interfacing LOCA were identified for each system reviewed.

The surveillance procedures were found to contain an adequate set of instructions which, if followed, will prevent an inadvertent overpressurization event. None of the design pressure interlocks are defeated or bypassed during system tests. Precautions are included in the LPCI and CS procedures to highlight the potential overpressurization problem.

The sequence for the HPCI and RCIC monthly tests require that at least one of the two injection valves be closed while testing the alternate valve. However, there are no administrative limits or precautions listed in either OP 4120 or OP 4121 to warn the opertor not to have both valves open at the same time. The test data sheets do not require that the operator first close the normally open valve prior to cycling the normally closed valve. The procedure does not require a second operator to independently verify that the final position of the injection valves.

The lack of such additional instructions in the HPCI and RCIC procedures does not appear to be a problem since (i) there have been no overpressurization events; (ii) operators generally follow the procedure instructions and do not rely solely on the data sheet; and, (iii) the operators are sensitized to the potential for pressurizing the upstream piping due to previous maintenance problems with the check valves.

OPs 4120 and 4121 could be improved by adding a precaution regarding the concurrent opening of both injection valves, and by incorporating a similar caution in the test data sheet. The cautions should be added to make the HPCI and RCIC procedures consistent with the other ECCS test procedures and to provide further assurance low pressure piping is not inadvertently pressurized.

The suggested procedure improvements were discussed with licensee personnel. This item is open pending completion of the licensee's evaluation of the suggested procedure change and subsequent review by the NRC (IFI 85-20-06).

11.3 Maintenance Practices and History - Maintenance activities for the check valves and the motor-operated injection valves on the LPCI, CS, HPCI and RCIC systems were reviewed. The position indication circuits and air operators were removed from the testable check valves as part of the modifications described in Section 11.1 above. Removal of these components reduced the number and type

of maintenance problems that could occur, and specifically precluded the occurrence of most of the failures described in the literature. Thus, the type of maintenance activities with a potential for causing concerns related to an interfacing event are limited to work where the valve internals are disassembled for inspection, rework, or repair. This type of work would most likely be done only with the plant in cold shutdown.

The MR documentation reviewed did not capture the independent verification that may have been done under the 'peer review' QC inspection coverage of the maintenance work. There has been no mechanical preventive maintenance done on the internals of the check valves or the MOVs. Electrical preventive maintenance checks were performed on the limitorque operators for the MOVs per OP 5220 approximately once per year since about 1980.

There are no plant procedures that specifically cover maintenance work on any of the valves reviewed, except for OP 5201, Safety System Valves, which does have a data sheet for the annual disc exercise of the RCIC 22 valve during plant shutdown. Vendor manuals are available and used for routine corrective maintenance. Within the scope of this limited review, the inspector concluded that much of the mechanical work performed on the valves was of the type that is "within the skills of the mechanic".

Since there are no specific maintenance procedures for the isolation valves, there are no pre-established pre-maintenance checks related to interfacing systems to assure correct removal from service. However, prior to completing work on the valves, they are removed from service in accordance with the AP 0025, Plant Equipment Control, AP 0021, Maintenance Requests, and AP 0140, Local Control Switching Rules. The inspector concluded that the controls in these procedures are sufficient to assure proper boundary protection is established prior to opening the valves, and to assure proper operability testing is completed prior to returning the valves to service following maintenance. No inadequacies were identified.

11.4 Previous Overpressurization Events - Based on discussions with plant personnel and a review of facility records, no overpressurization event was identified, other than the one on the LPCI system on December 12, 1975. This event was described in LER 75-24 and the AEOD literature and occurred while performing the monthly Technical Specification test of the LPCI injection MOVs. The licensee revised the procedures that test the injection valves and the changes appear to have been effective to preclude a recurrence of the event.

11.5 Operator Review of Operating Experiences - Based on interviews with 6 members of the maintenance, operations and I&C staffs, the inspector determined that Information Notice 84-74 was received onsite, disseminated through the Operating Assessment Review Program, and reviewed by applicable facility personnel. Personnel were familiar with the test and maintenance requirements in procedures for which they are responsible. Additionally, the operations personnel appeared to be sensitive to the potential for configurations that can pressurize low pressure piping due to operational problems experienced with the RCIC and core spray systems.

11.6 Conclusions - The Vermont Yankee design and procedures were reviewed in light of industry experiences and no weaknesses were identified that should be addressed to preclude similar problems at Vermont Yankee. The only procedure items that warrant further attention are summarized in section 11.2 above. The inspector concluded that the present combination of design features, staff experience, administrative controls and operator training are sufficient to preclude a concern regarding the potential for an interfacing overpressurization event at Vermont Yankee.

12.0 Emergency Communications Equipment

12.1 Public Notification System

The licensee conducted a test of the Public Notification system on June 27, 1985 as part of an evaluation by the Federal Emergency Mainagement Agency (FEMA). The test consisted of activating both the NOAA Alert radios and sirens in selected communities, followed by a telephone survey by FEMA representatives to determine whether the public had received the notifications. The exercise also included a test of the Emergency Broadcast networks in Vermont, New Hampshire and Massachusetts.

The test results will be reported by FEMA at a later date and will be followed by the inspector on a subsequent inspection to determine whether any deficiencies were identified (IFI 85-20-07).

12.2 Information Notice 85-44: Communication System Testing

Information Notice 85-44 was discussed with the Emergency Plan Coordinator to determine what tests are conducted on the emergency communication systems. The licensee conducts monthly tests of the ENS telephones (CR, TSC and EOF), but not the HPN network. Based on the clarification provided in IN 85-44, the licensee stated that OP 3506 will be revised to test the HPN circuit monthly, beginning in July, 1985.

The licensee stated the actions are in progress to install emergency response equipment in the new EOF facility in Brattleboro, which is scheduled to be operational prior to the November 1, 1985 commitment date. A problem was identified by the telephone company concerning the installation of the HPN network, which would require a piece of hardware that is no longer available. The difficulty in obtaining the hardware was confirmed based on a discussion with the telecommunications group in NRC:Headquarters.

The inspector determined that the NRC intends to replace the present HPN system in the near future with a standard commerical line that is routed through a "foreign exchange". The inspector stated that the licensee should (i) provide written notification to the NRC regarding the problem of installing the HPN at the new EOF: and, (ii) provide, at a minimum, a dedicated commercial line at each location in the EOF where an HPN phone would have been provided. The inspector suggested that the licensee consider providing a commercial line routed through a "foreign exchange".

This item will be followed on a subsequent inspection to review licensee actions regarding testing of the present HPN lines, and the installation of a phone system dedicated to health physics information at the new EOF (UNR 85-20-08).

13.0 Document Control Procedures

The licensee notified the inspector on June 26, 1985 of the results of an audit in the Document Control Area that identified a potential violation of QA program and ANSI N45.2.9 requirements. The problem involved the lack of references in DCC procedures AP 6806, AP 6808 and AP 0834 regarding the instructions used in DCC to process, control and retain permanent records of licensed activities.

The procedures used by plant personnel are taken from the YAEC Document Control Manual. The procedures were included by reference in plant procedures up until 1983 when they were deleted by revision to the plant procedures, due to the confusion and problems that were created between the forms in the Vermont Yankee procedures and those forms that were a part of the YAEC instructions. The appropriate YAEC procedures were used by plant personnel from 1983 until the present in spite of the lack of references in Vermont Yankee procedures.

The licencee's corrective action included revising Vermont Yankee procedures to incorporate the YAEC procedures by reference, as follows: Revision 5 to AP 6806; Revision 4 to AP 6808; and, Revision 13 to AP 0834. The revised procedures are scheduled to be approved and issued by September 1, 1985. This licensee's action on this item will be followed on a subsequent inspection (UNR 85-20-09).

This item will not be cited by the NRC since the item meets the criteria of Appendix C of 10 CFR Part 2, and the licensee corrective actions, taken and planned, are appropriate.

14.0 Strike Contingency Plans

On June 12, 1984, due to the impending expiration on the existing union contract at the site and the possibility of a strike, the inspector reviewed the capability of the licensee to safely operate the reactor under such conditions. The inspector reviewed the number of licensed operators not covered under the contract to determine whether shift manning requirements could be met. The inspector found that sufficient licensed operators would be available when non-shift, staff-licensed operators are considered. For these staff operators, the inspector reviewed recent requalification training records to verify their training was current and reviewed the control room log to verify that they had stood watch during the prior four months to maintain their license.

The inspector interviewed the supervisors of chemistry and health physics, administration, maintenance and instrumentation and control to review their department's capability on strike conditions. The inspector concluded that the licensee had sufficient capability to operate the reactor safely for a limited time under strike conditions.

Later, a new contract was signed prior to the expiration of the existing contract on June 17, 1985, and no strike occurred.

15.0 Followup on Actions on Selected Safety Issues

The inspector performed a special review required by Temporary Instruction TI 2515/67 to determine the actions taken by the licensee in response to certain safety issues identified by the industry. The problem selected for review concerned mispositioned control rods as described in Information Notice 83-75. The inspector verified that procedures OP 2111, 2450 and 4424 contain appropriate instructions to preclude the occurrence of problems similar to those described in IN 83-75. Plant personnel received appropriate training regarding control rod movement. No inadequacies were identified.

16.0 Management Meetings

Preliminary inspection findings were discussed with licensee management periodically during the inspection. A summary of findings for the report period was also discussed at the conclusion of the inspection.