U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

Region I

Report No. 50-271/80-10

Docket No. 50-271

License No. DPR-28 Priority -- Category C

Licensee: Vermont Yankee Nuclear Power Corporation
25 Research Drive
Westborough, Massachusetts 01581

Facility Name: Vermont Yankee

Inspection at: Vernon, Vermont

Inspection conducted: July 5-August 8, 1980

Inspectors: W. J. Raymond, Senior Resident Inspector — 10/7/80 date signed

S. J. Collins, Resident Inspector — 10/7/80 date signed

T. Foley, Resident Inspector — 10/7/80 date signed

S. Hudson, Resident Inspector - Trainee — 10/7/80 date signed

Approved by: T. T. Martin, Chief, Reactor Projects Section No. 3, RO&NS Branch — 10/7/80 date signed

Inspection Summary: Inspection on July 5-August 8, 1980 (Report No. 50-271/80-10)
Areas Inspected: Routine, unannounced inspection by the resident inspectors of Plant Operations, including review of logs, records and tours of plant areas; Safety System Operational Verification; Followup of Operational Events; Witness of Surveillance Tests; Fire Protection Program Surveillances; Transportation of Radioactive Material; new fuel receipt inspections; new fuel inspection and channeling activities; IEB 80-17, BWR Scram System responses; including special testing, measurements, procedure controls and transient analyses (TI 2515/39); Backup Scram Valve Operability; Diesel Generator Air Start System Modification Package; location of essential load centers; LER 80-24 followup; PORC activities and functions; licensee problem reports; licensee plans for coping with strikes; implementation of strike plans; and, observations of plant physical security. The inspection involved 162 inspector-hours onsite by three resident inspectors.
Results: No items of noncompliance were identified.

Region I Form 12
(Rev. April 77)

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DETAILS

1. Persons Contacted

Mr. R. Branch, Assistant Operations Supervisor
Mr. R. Creek, Maintenance Foreman
Mr. P. Donnelly, Instrument and Control Suervisor
Mr. H. Fitzroy, Day Shift Supervisor
Mr. S. Jefferson, Reactor Engineering Supervisor
Mr. R. Leach, Health Physicist
Mr. M. Lyster, Training Supervisor
*Mr. W. Murphy, Plant Superintendent
*Mr. J. Pelletier, Assistant Plant Superintendent
Mr. W. Penniman, Security Supervisor
Mr. R. Sojka, Operations Supervisor
Mr. G. Wallin, Reactor Technician
Mr. D. Weyman, Chemistry and Health Physics Supervisor
Mr. W. Wittmer, Maintenance Supervisor

The inspectors also interviewed other licensee employees during the inspection, including members of the Operations, Health Physics, Instrument and Control, Maintenance, Reactor Engineering, Security and General Office staffs.

*denotes those present at exit interviews.

2. Review of Plant Operations

a. Shift Logs and Operating Records

The inspector reviewed, on a sampling basis, the following logs and records for the period of June 5 to August 8, 1980.

-- Shift Supervisor's Log
-- Control Operator's Round Sheet
-- Night Order Book
-- Primary System Leakage Surveillance Logs

The review consisted of verifying adequate management review, correct identification of problem areas, completeness and determination that conditions contrary to Technical Specifictions did not exist.

No items of noncompliance were identified.

b. Inspection Tours

The inspectors toured the following accessible plant areas at various times during the inspection:

-- CW house and intake structure
-- control room
-- all levels of the reactor building, including the corner rooms
-- all levels of the turbine building
-- exterior of the torus
-- diesel generator rooms and switchgear room
-- drywell 251 foot elevation
-- AOG Building

The following observations and determinations were made:

-- Radiation Protection Controls: step off pads, storage and disposal of protection clothing, and control of high radiation areas were observed in all areas toured. Radiation Work Permit (RWP) controls established for various routine work in the plant were monitored for proper implementation. Standard RWP numbered 00628 issued 7/11/80 for work inside the drywell was reviewed for adequacy and proper implementation in accordance with AP 0502. Health physics controls in effect for work on value V-2-54B was observed on 7/13/80 to be in accordance with the applicable RWP.

-- Fluid leaks: all areas toured were examined for evidence of excessive fluid leaks.

-- Control Room Shift Manning: this area was observed to verify compliance with minimum staffing requirements.

-- System Operability: selected valve positions, breaker and equipment start positions were reviewed to verify plant normal operating systems and standby emergency systems were operable in accordance with Technical Specification requirements for the applicable reactor mode. Systems and subsystems observed included the following: diesel generators, offsite transmission circuits, onsite 4KV distribution system, feedwater/condensate, reactor recirculation, control rod drive, reactor water cleanup, advanced offgas, standby liquid control, low pressure coolant injection, reactor core isolation cooling, core spray, residual heat removal, residual heat removal service water, high pressure coolant injection, service water, drywell purge and ventilation, and, primary containment isolation.

-- Annunciated Conditions: Discussions were held with control room personnel pertaining to the reason for lighted annunciators. The control operators were knowledgeable of the reasons for all lighted annunciators.

-- Plant housekeeping and cleanliness were noted.

-- LSSS/LCO: equipment status and operating parameters were observed for conformance with LSSS/LCO requirements. Parameters and equipment monitored included core thermal power; reactor pressure; drywell/torus differential pressure; torus water level and temperature; control rod accumulator pressure and level; liquid poison tank level; condensate storage tank level; reactor coolant system leakage; recirculation loop header equalizer valves; plant gaseous release rates; and, core total peaking factor, minimum critical power ratio and linear heat generation rates.

-- Monitoring Instrumentation: remote (control room) and local monitoring instrumentation was observed to verify its operability and to detect indications of anomalous system operation or conditions. Instrumentation reviewed during this inspection included the nuclear instrumentation; reactor coolant level, pressure and temperature; jet pump; meteorological; reactor vessel steam flow and feedwater flow; containment temperature, pressure, level and differential pressure; process and area radiation monitors; off gas and stack radiation monitors, recirculation pump pressure, temperature, amperage, flow and seal pressures; drywell floor drain and equipment drain temperature and flow integrators; steam leak detection; river water temperature; station air system; SV/SRV leakage monitoring; and 345KV, 4KV and 480VAC electrical system instrumentation.

-- Shift turnovers of control room operators and supervisors were observed on regular and backshifts to verify that transfer of the shift was orderly and that continuity of plant status information was maintained.

-- Portable fire fighting equipment was observed for current inspection stickers and indicated charges within the operable range. (See paragraph 6 below for further discussions in this area.)

No items of noncompliance were observed and, except as noted below, the inspector had no further comments in this area.

(1) During an inspection tour on 7/22/80, the inspector noted a reactor water cleanup system (RWCU) room temperature alarm in effect on the steam leak detection panel. RWCU room temperature indication from TE 12-117D was just above the alarm setpoint of 115°F. The alarm was discussed with control room personnel, who were knowledgeable of the alarm and its cause. Licensee investigation of the alarm revealed no steam leak in the RWCU room. The elevated temperature on TE 12-117D was due to its proximity to a reactor building fan cooling unit, which in turn, was operating warm due to a combination of high service water temperatures (caused by river water temperatures as high as 78°F) and an accumulation of dirt on the fan cooling coils. Radiation levels in the RWCU room are sufficiently high during normal plant operation to preclude entry into the room for routine housekeeping activities. The inspector had no further comment on this item.

No items of noncompliance were identified.

(2) During inspection tours on 7/15/80, the inspector witnessed licensee radiation surveys in progress on two LSA packages in preparation for shipment to the offsite burial ground (Barnwell, South Carolina). The intended shipment consisted of old spent fuel racks, packaged in 7.5'Wx8'Hx15'L wooden crates, marked as boxes 1 and 2. The inspector observed and confirmed radiation measurements taken on contact with the boxes and at 6 feet distances. The inspector noted that both survey instruments in use by licensee HP technicians were within the specified calibration intervals. All measurements on box #1 were less than 200 mR/hr on contact and less than 10 mR/hr at 6 feet from the sides of the box. Based on these results, box #1 was deemed acceptable for transport offsite pursuant to the requirements of 49 CFR 173.393(i).

Measurements taken on box #2 also showed radiation levels of less than 200 mR/hr on contact and less than 10 mR/hr at 6 feet from the box. However, one measurement taken at 6 feet read 9.5 mR/hr, and based on this measurement, shipment of box #2 was delayed pending additional review and preparation by the licensee.

The inspector had no further comment on this item. No items of noncompliance were observed.

(3) During inspection tours on 7/30/80, the inspector noted a plywood box containing LSA material in temporary storage on the East end of the Radwaste Building (outside) and immediately

adjacent to waste sample tank 1B. The box had a standard Radiation Area placard affixed to it, with dose rates marked on the placard indicating radiation levels of 40 mR/hr at 18 inches from the box. The inspector performed radiation surveys on the box, noted no levels higher than 90 mR/hr on contact with the box, and noted that the licensee's posting information was accurate. The inspector did note, however, that the Radiation Area sign on the box was located such that it was visible from all directions of approach to the box, except one. A person could approach the box through the radwaste tank farm area (not a radiation area) without seeing the sign or being aware he had entered a radiation area. This matter was brought to the attention of the plant Health Physicist and an additional sign was posted on the box. The inspector noted that the box was subsequently removed from the area by the licensee.

The inspector had no further comment on this item. No items of noncompliance were identified.

(4) The inspector noted during a review of the shift supervisor's log on 7/30/80, that the cooling fans on the plant main transformer became inoperable at 3:30 a.m. on 7/30. Plant load was reduced to 50% FP to investigate the problem. Subsequent investigation by the licensee determined that the cooling fans stopped as a result of blown fuses in the potential transformer compartment and that failure of the fuses was not attributable to abnormal currents in the subject circuitry. The fuses were replaced, the fans restarted and plant load was returned to full power. Full power operation was resumed with no further problems with the transformer cooling fans. This item was discussed with the Day Shift Supervisor. No conditions were identified which affected limiting conditions for operation on equipment required to be operable by the Technical Specifications.

The inspector had no further comments on this item. No items of noncompliance were identified.

(5) During tours on 7/30/80, the inspector noted that relay flags were "up" on the DC Control Power-Normal/Alternate Full Synchronization Check Relays for fuses 12 and 22. During separate, unrelated observations, same date, the inspector noted that drag indicators associated with temperature gauges on the main, auxiliary #2 and startup 3A/3B transformers had not been reset. The above items were forwarded to the shift supervisor for evaluation/action. The relay flags and drag indicators were subsequently reset by the licensee.

Both items were apparently related to the loss of cooling fans on the main transformer (discussed above) and the transfer of plant house loads from the normal to alternate supply.

The inspector had no further comment on this item. No items of noncompliance were identified.

(6) During inspection tours on 7/30/80, the inspector noted T-quenchers laying in storage on the South yard. The T-quenchers are a part of the VY Mark I torus modifications scheduled to be completed during the 1980 refueling outage. Visual inspection of the components revealed what appeared to be rust located around the heat-affected-zones of several butt welds. In that the T-Quenchers are made from schedule 80 stainless steel piping, it was not apparent to the inspector what mechanism led to the formation of rust, nor the significance of the rust deposits. This matter was forwarded to licensee personnel for review and evaluation.

This item will be followed on subsequent inspections (50-271/80-10-01).

(7) During inspection tours on 7/31/80, the inspector noted that the B diesel generator room was in need of cleanup. The inspector also noted that a fire stop for a cable tray that penetrates the floor of the reactor building second level (NW corner) had been altered during cable installations. The cable tray fire stop appeared functional at the time of the inspector's observations. These items were reported to a licensee representative for review and action.

Diesel generator room housekeeping was subsequently observed by the inspector and found to be improved. The licensee subsequently reported that the subject cable tray had been opened to run cable for new reactor vessel level instrumentation. The inspector subsequently observed that the cable tray and fire stop had been returned to a normal configuration.

The inspector had no further comments on this item. No items of noncompliance were identified.

3. <u>System Operational Safety Verification</u>

A detailed review was conducted on the Core Spray System, Trains A and B during the period July 22-23, 1980, to verify the system was properly aligned and fully operational in the standby mode. Review of the above system included the following:

a. verification that each accessible valve (manual and power operated) in the flow path was in the correct position by either visual observation of the valve or remote position indication. Plant procedure OP 2123 and drawing G-19166 were used to verify proper Core Spray System lineups.

b. verification that power supplies and breakers were properly aligned for components that must actuate upon receipt of an initiation signal.

c. visual inspection of major components for leakage, proper lubrication, cooling water supply, general condition and other conditions that might prevent fulfillment of their functional requirements.

d. verification by observation that instrumentation essential to system actuation and performance was operational.

Except as noted below, no inadequacies were identified during this review.

The inspector noted that core spray pump B discharge pressure transmitter root isolation valve V804B was erroneously labeled as 4804A on drawing G191168. This item was forwarded to a licensee representative, who stated that the valve label will be changed on the next corrective update of the subject print. The inspector had no further comments on this item. No items of noncompliance were identified.

4. Inspector Followup of Events

The inspectors responded to events that occurred during the inspection to observe/review the licensee's response to the events and to verify continued safe operation of the reactor in accordance with the Technical Specifications and regulatory requirements. Some or all of the following items, as applicable, were considered during the inspector's review of operational events:

-- observations of plant parameters and systems important to safety to confirm operation within normal operational limits;

-- description of event, including cause, systems involved, safety significance, facility status and status of engineered safety features equipment;

-- details relating to personnel injury, release of radioactive material and exposure to radioactive material;

-- verification of correct operation of automatic equipment;

-- verification of proper manual actions by plant personnel;

-- verification of adherence to plant procedures;

-- verification of conformance to Technical Specification LCO requirements;

-- determination that root causal factors were identified and that corrective actions, taken or planned, were appropriate to correct the cause;

-- verification that corrective action taken was appropriate to prevent recurrence;

-- determination whether the event involved operation of the facility in a manner which constituted an unreviewed safety question as defined in 10 CFR 50.59 (a) (2), or in such a manner as to represent an unusual hazard to health and safety of the public and environment;

-- determination whether the event involved continued operation of the facility in violation of regulatory requirements or license conditions; and,

-- evaluation of whether applicable reporting requirements were met.

Operational events reviewed during this inspection are discussed below.

a. Leakage into Drywell - Recirculation Valve V2-54B

On July 10, 1980 at 12:30 p.m. plant operators noted indications of leakage into the drywell based on the following information:

-- the containment particulate air monitor radiation level increased from a normal reading of 4000 cpm to 1.0xE6 cpm.

-- RRU#4 cooling water outlet temperature increased by 2°F.

-- drywell/torus differential pressure increased from a nominal value of 3.8 inches Hg to 4.6 inches Hg, indicative of an increase in drywell pressure.

-- leak rate (identified) from the drywell equipment drain sump (DWEDS) increased from 1.3 gpm to 2.4 gpm.

-- leak rate (identified) from the drywell floor drain sump increased from zero to 1.3 gpm.

-- valve open position lights for main steam line inboard isolation valve MSIV 80-A went out after providing erratic indications.

Based on the above, plant load was decreased to 75% FP at 4:00 p.m. on 7/10 to allow an operations team to enter the drywell and inspect for leakage. Leakage was suspected to be in the vicinity of MSIV 80-A due to the erratic open position indication.

As a result of the drywell inspection, no leakage was noted in the vicinity of MSIV 80-A, nor any obvious reason for the loss of open indication. The open status indication for MSIV 80-A is discussed in further detail below. A packing leak was observed on the 4 inch diameter B recirculation pump discharge bypass valve, V2-54B. Valve V2-54B is a split disc gate valve located in parallel with the B recirculation pump main discharge valve and serves a function primarily during the startup of the recirculation pump. Although there is no required position for the valve during routine plant operations, it is normally kept closed. After several unsuccessful attempts by plant personnel to limit/stop the packing leak by backseating the valve, the valve was returned to the closed position, which was considered fail-safe.

Leakage from the valve was observed to spray down through the floor grating on the drywell 252'6" elevation, strike a drywell/torus vent shield located below the valve, and onto the drywell floor where all leakage water was collected by the DWFDS. After verifying that identified and unidentified leak rates stabilized at 1.3 gpm and 2.59 gpm, respectively, no further action in regard to the valve was deemed necessary by the licensee at that time. A temporary change to the drywell leakage surveillance procedure was made to administratively treat the 1.3 gpm DWFDS leakage as identified leakage, with additional instructions provided to control room personnel to closely monitor leak rates. Increased leakage monitoring was accomplished by recording and plotting DWFDS and DWEDS data every two hours. Plant escalation to full power operation was commenced at 7:00 p.m. on 7/10/80.

The inspector reviewed the actions taken by the licensee, the drywell leakage data and the recently imposed reductions in allowable identified and unidentified (reference: NRC Region I Inspection Report 50-271/80-08). No inadequacies were identified. The inspector stated that should DWFDS leakage increase to 3.8 gpm, then action would have to be taken in accordance with the administrative limits to further investigate the leak rate and/or shutdown the reactor. The licensee acknowledged the inspector's comments.

Monitoring of drywell leakage continued during the period of July 10-11. By 2:30 p.m. on July 11, DWEDS and DWFDS leak rates had increased to 4.05 gpm and 2.6 gpm, respectively, with indications that the packing leak on valve V2-54B was slowly getting worse. The plant was shut down during the morning of July 12 to effect repairs of the valve in conjunction with testing performed in accordance with IE Bulletin 80-17 requirements. The inspector accompanied a maintenance crew into the drywell on July 13, 1980 to observe final inspection and adjustments made to V2-54B following replacement of the packing. No inadequacies were identified.

The inspector had no further comment on this item. No items of noncompliance were identified.

b. MSIV 80-A Open Status Indication

During the period of July 9-11, the open status indication lights for MSIV 80-A, located on both the CRP 9-5 vertical and horizontal boards, became erratic and finally extinguished altogether. Inspection of the valve position indication limit switches during drywell entries on July 10 and July 11-13 revealed no obvious causes for the malfunction. Direct observation of the valve while it was cycled using the control room control switch showed that the valve could be stoked over its length of travel without binding and that the valve was physically full open in spite of the lack of open indication. Further investigation of the matter by the licensee showed the following:

-- functional testing of MSIV 80-A verified that the value stoked smoothly and within the cycle times required by the plant technical specifications.

-- no RPS input to indicate 10% closure of the valve existed (the signal used for the RPS input is derived from separate position indication circuitry).

-- RPS 10% closure functional testing verified that the 10% closure circuitry operated as required.

-- the green, CLOSED indication status lights were functional and therefore, available to the control room operator should verification of primary containment isolation be required.

-- steam flow indications on all four steam lines were normal and did not indicate partial closure of any valve.

Based on the above, the licensee concluded that the problem associated with MSIV 80-A was limited to the valve full open

position indication circuitry and that the MSIV was operable. A maintenance request was issued to investigate and repair the position indication circuitry on a subsequent plant shutdown. This item will be followed in a subsequent inspection (50-271/80-10-02).

c. Recirculation Pump Motor Cooler

On August 4, 1980 a CRP 9-4 annunciator panel alarm came in on the B recirculation pump which indicated a cooling water leak had developed on the pump motor cooler. No other indications of pump abnormal operation or conditions were present. At 2:00 p.m., August 4, plant load was reduced to 70% FP to allow a drywell entry and inspection of the B recirculation pump.

The motor cooler leakage alarm signal is derived from a level switch mounted on the recirculation pump motor housing, which senses water level in an internal collection chamber at the base of the motor housing (reference: Drawing G-191159, Sheet 5). The licensee inspected the collection chamber through an inspection port located on the motor housing and confirmed that no water had accumulated and that no evidence of motor cooler leakage existed. The float switch arrangement on the level indicator was found to be faulty and several attempts to correct the level sensor were unsuccessful. Adverse environmental conditions inside the drywell and ALARA considerations hindered further repair efforts with the plant at power. Based on the above information, a prior history of leakage free operation on the motor coolers and the lack of other indications of pump abnormal operation, the licensee decided to resume full power operation with the alarm in effect, and conduct further investigation/repair of the motor cooler leakage circuitry on a subsequent plant shutdown.

The inspector's review of this item considered the above information together with Technical Specifications, FSAR and equipment operability requirements and the plant safety/transient analyses. No conditions that would constitute unsafe operation were identified. The inspector had no further questions on this item at this time; however, this item will be followed on subsequent inspections (50-271/80-10-03).

5. Inspector Witnessing of Surveillance Tests

The inspector witnessed portions of and reviewed documentation associated with the following surveillance test activities:

-- Reactor Water Lo Lo Level Scram - High/Lo Water Isolation/Calibration, OP 4314, Revision 13;

-- Reactor Water Level ECCS Initiation Functional/Calibration, OP 4337, Revision 10;

-- Main Turbine Trip High Water Level Functional/Calibration, RP 4395, Revision 7; and,

-- Main Steam Line High Radiation Level RPS Trip Calibration/Functional Test, OP 4315, Revision 3, inclusive of DI 79-30 dated 10/23/79.

The inspector verified by personnel observation and document review that the surveillance test procedure was properly approved and in use; technical specifications were satisfied prior to removal of the system from service; test was performed by qualified personnel; test schedules were complied with; test results were properly recorded and satisfied the procedural acceptance criteria; and, temporary changes were properly approved and did not involve a change in test intent or test scope.

The following documents were reviewed by the inspector:

-- Vermont Yankee Nuclear Power Station Technical Specifications;

-- Lifted Lead/Installed Jumper Request No. 800045;

-- Vermont Yankee Nuclear Power Corporation Instrument and Control Department, Performance Standard Evaluation;

-- Recertification record for Vermont Yankee Control instrument specialist;

-- Instrumentation and Control Department Yearly Review;

-- Record of Surveillance Test Performance;

-- Certification Record for Vermont Yankee Control Instrument Specialist;

-- I&C Department indoctrination and check-in forms, and

-- Completed data sheets for OP 4315, OP 4313, OP 4337, and RP 4395 dated April 22, 1980.

There were no unacceptable conditions identified.

6. Fire Protection System Surveillances

During a plant inspection tour on July 23, 1980, portable fire extinguishers were examined at various locations throughout the plant to verify proper implementation of the licensee's fire extinguisher surveillance program. Approximately 25 extinguishers were inspected at random. Of

those inspected, the inspector noted two fire extinguishers (Nos. 18 and 20) with operating pressures below the "acceptable charge range" on the pressure indicators. Neither of the inspection tags affixed to the extinguishers had been initialed and dated, as required by OP 4020, Revision 7, Surveillance of Fire Protection Equipment, to indicate that the units had been inpsected during the July inspection interval.

Further review of this matter by the inspector revealed that the subject fire extinguishers had been inspected by the licensee on July 7, 1980 and were found in need of recharge, as evidenced by remarks on data sheet OP 0402.04. The respective inspection tags were left unsigned pending completion of corrective maintenance. However, the inspector also noted that the remarks on OP 4020.04 indicating the subject units were in need of recharge had been lined out, the Shift Supervisor, Operations Supervisor and Fire Protection Coordinator review blocks were completed, and the surveillance was signed off as complete on July 10, 1980. This matter was discussed with the Operations Supervisor, who has responsibility for implementation of the surveillance. Action was taken immediately to replace fire extinguishers nos. 18 and 20 with ones having full charges. The Operations Supervisor was asked to determine how replacement of the fire extinguishers was overlooked.

Following discussions with the individuals involved with the surveillance, the Operations Supervisor determined that the manner in which the data sheet was completed caused correction of the condition to be overlooked. The individuals involved were re-instructed regarding the appropriate procedures to follow and a memorandum was issued to all shift supervisors.

The inspector noted the corrective actions taken and considered them appropriate. The inspector also noted that this item appeared to be an isolated incident based on the present and previous reviews in this area. Review of the fire protection surveillance program for proper implementation will be covered on subsequent routine inspections.

Based on the above, the inspector had no further comments on this area at the present time.

7. Transportation of Radioactive Material

The inspector verified by record review, direct observation, and discussion with licensee representatives that implementation of licensee procedures for loading low specific activity (LSA) radioactive waste on a tractor-trailer in preparation for material shipment number 80-40 was acceptable.

During the loading of the thirteen wooden boxes on the open flatbed trailer the inspector observed the following activities:

-- shipping paper documentation,

-- package labeling, and

-- control of contamination and radiation levels.

The inspector performed a review of the following documentation relating to material shipment number 80-40:

-- OP 2511, Revision 6, Radwaste Cask, Drum and Box Handling;

-- Prior Notification Form, to Chem Nuclear Systems, Inc., of Barnwell, South Carolina;

-- South Carolina Department of Health and Environmental Control Radioactive Waste Shipment Certification Form for Shipment 80-40;

-- Radioactive Shipment Record Form;

-- State of Connecticut Department of Transportation Application for Radioactive Permit;

-- Radioactive Material Shipment Report - Shipment 80-40;

-- Vermont Yankee Nuclear Power Corporation Radioactive Shipment Record 80-40-1; and

-- Hittman Nuclear and Development Corporation Radioactive Shipment Record, Shipment 80-40.

During the review the inspector noted that one of the thirteen boxes of LSA material appeared to have inadequate labeling. The licensee was informed of the issue and immediate corrective action to rectify the labeling discrepancy was taken.

The inspector verified by independent measurements that each box of LSA material complied with Department of Transportation (DOT) requirements for maximum permitted radiation levels on contact, and at six feet from each container.

The inspector observed final placarding of the shipment following installation of the trailer cover and immediately prior to the carrier leaving the site. The inspector verified by direct observation that the required standardized vehicle placards were installed on the exterior of the shipment per 49 CFR 172.556.

The inspector had no further questions in this area.

8. Receipt of New Fuel

The inspector reviewed licensee procedure OP 1400, Revision 10, Fuel Receipt and Preliminary Handling, to verify that a technically adequate, approved procedure was available to support the receipt, inspection and storage of new fuel in preparation for the scheduled 1980 Vermont Yankee refueling outage.

There were no unacceptable conditions identified.

The inspectors observed receipt, inspection and storage of the following fuel bundles by licensee personnel to verify the activities were conducted in accordance with approved procedure OP 1400, Revision 10:

-- LJT 035	-- LJP 237
-- LJT 045	-- LJP 193
-- LJP 267	-- LJP 234
-- LJP 238	-- LJP 266
-- LJT 042	-- LJP 263

Activities observed included the following:

-- Arrival of new fuel on-site and transportation of crates to inspection area;

-- Uncrating and inspection of fuel bundle inner containers;

-- Radiation surveys associated with new fuel handling; and,

-- Transportation to, and storage of the inner containers on the refueling floor in preparation for fuel inspection and channeling.

During the course of the inspection in this area the following documents were reviewed:

-- Fuel Receipt and Preliminary Handling, OP 1400, Revision 10;

-- Fuel Receiving Supervisor's Check Sheet, VYOPF 1400.01, Revision 10;

-- Fuel Container Check Sheet, VYOPF 1400.02, Revision 10; and,

-- Health Physics Activities During New Fuel Receipt and Inspection, AP 1500, Revision 9.

During the review of the documentation associated with new fuel receipt, the inspector noted that several typographical errors existed on the vendor (General Electric) supplied "Domestic Memo of Shipment". Further investigation revealed that for VY Shipment 80-02, one typographical error existed in that bundle number LJT 036 was recorded as LJP 036, and for VY shipment 80-03, three typographical errors existed in that bundle numbers LJT 039 and LJT 045 were recorded as LJP 039 and LJP 045, respectively and Inner Container No. I3701 was recorded as R3701. Licensee personnel stated that the correct bundle number was verified by comparison with the Product Qualification Certification (PQC) and by visually reading the bundle number during new fuel inspection. The correct container serial number prefix was determined to be "I", since it pertained to the inner metal container. The inspector noted that licensee personnel corrected the typographical errors on the applicable "Domestic Memo of Shipment", initialed the changes and noted that correct bundle numbers were verified by review of the PQC. The inspector determined by independent review that the bundle serial numbers visually verified by the licensee's qualified New Fuel Inspector and recorded in VYOPF 1401.02, Fuel Assemblies Check Sheet, correspond with the bundle serial numbers from the vendor supplied PQC and those corrected by licensee personnel on the Domestic Memo of Shipment.

The inspector had no further questions in this area. No items of noncompliance were identified.

9. New Fuel Inspection Activities

a. Fuel Inspection

The inspector observed performance of new fuel inspection and channeling, and the qualification of licensee new fuel inspectors by a GE vendor representative to verify the activities were performed in accordance with the licensee's approved procedures.

During these activities the inspectors observed licensee preparations for the movement of new fuel, removal of new fuel from metal shipping containers, fuel surveys, movement of new fuel to the inspection stand and fuel assembly inspection. A vendor representative (General Electric) was on-site for new fuel inspection and delivery of inspection tools to the licensee. The inspectors observed the GE representative inspect the initial fuel assembly and subsequently qualify licensee new fuel inspectors. The remaining new fuel inspections were conducted by licensee inspectors.

During the course of the inspection the following documents were reviewed:

-- New Fuel Inspection and Chanelling, OP 1401, Revision 8, Procedure Sections A., B., and C;

-- New Fuel Inspection Check Sheet VYOPF 1401.01, Revision 8;

-- Fuel Assemblies Check Sheet VYOPF 1400.02, Revision 8;

-- Radiation Work Permit (RWP), 80 No. 0666; and,

-- AP 0502, Radiation Work Permit, Revision 9.

Except as noted below, no unacceptable conditions were identified.

b. Review of Posted Surveys Associated with New Fuel Inspection

During the review of documentation associated with New Fuel Inspection, the inspectors observed that a posted survey noted that a contamination area greater than 10,000 dpm/100 cm^2 existed adjacent to the area in which the fuel inspection activities were being conducted. Licensee Administrative Procedure 0502, Revision 9, specifies that an RWP is required for entry into an area of contamination greater than 10,000 dpm/100 cm^2. The inspectors noted that two plant employees and two vendor representatives were observing the new fuel inspection activities without wearing all the proper protective clothing as specified by RWP 80 No. 0666. Further investigation revealed the observers were not actually working under the subject RWP; however, the potential existed for the personnel to be within the contaminated area without proper RWP controls.

The inspector informed the licensee's representative that the licensee's current posting requirements do not prohibit personnel, not on a RWP, from inadvertently entering a contaminated area greater than 10,000 dpm/100 cm^2 and therefore not adhering to RWP requirements. The licensee's representative agreed and stated that a change to Administrative Procedure 0503, Establishing and Posting Controlled areas, would be issued within 30 days requiring that any contaminated area greater than 10,000 dpm/100 cm^2 be posted as an area requiring a RWP for entry. This item will be reviewed during a future NRC inspection (271/8010-04).

The inspector had no further questions in this area.

10. IEB 80-17: BWR Scram System

Licensee actions concerning IE Bulletin 80-17 were reviewed by the inspector to verify that: the Bulletin was forwarded to appropriate onsite management; a review for applicability was performed; information discussed in the licensee's reply was accurate; corrective action taken was as described in the reply; and the reply was within the time period described in the Bulletin.

a. References

-- IE Bulletin 80-17, Failure of Control Rods to Insert During a Scram at a BWR, dated 7/3/80; plus supplement no. 1 dated 7/18/80 and supplement no. 2 dated 7/22/80.

-- VY letter WVY 80-98 to NRC dated 7/8/80.

-- VY letter WVY 80-100 to NRC dated 7/13/80.

-- VY letter WVY 80-102 to NRC dated 7/18/80.

-- VY letter WVY 80-109 to NRC dated 7/28/80.

-- Special Test Procedure (STP) 80-01, Test Procedure to Fulfill the Requirements of IE Bulletin 80-17, Paragraph 2, dated 7/11/80.

-- RP 4398, RPS Scram Reset Delay Functional/Calibration, Revision 2, dated 6/12/78.

-- OP 4213, Special UT Procedure for Liquid Level Determination.

-- OP 2114, Operation of the Standby Liquid Control System, Revision 8, dated 4/16/80.

-- Department Instruction (DI) 80-38 to OP 2114 dated 8/1/80.

-- DI 80-36 to OP 3130 dated 7/3/80.

-- DI 80-39 to OP 2111 dated 8/1/80.

-- OP 3100, Reactor Scram, Revision 9, 7/11/80.

-- AP 0150, Responsibility and Authority of Operations Department Personnel, Revision 13, 7/11/80.

-- Drawing G-191170, Control Rod Drive Hydraulic System, Revision 10, 2/25/75.

-- GE Procedure FPF 80-148, UT Procedure for Detection of Water.

b. Procedure Review

A detailed procedure review was conducted on July 11, 1980, prior to the performance of scram testing required by IEB 80-17. The following procedures were reviewed.

-- STP 80-01, Test Procedure to Fulfill the Requirements of IEB 80-17, 7/11/80.

-- Special UT Procedure for Liquid Level Determination.

The procedures were reviewed to verify that they were technically adequate and would accomplish the intended purpose, and to verify that they were prepared and approved in accordance with licensee requirements. The inspector had minor comments on STP 80-01, which were discussed with licensee personnel and incorporated into the final procedure prior to the conduct of testing.

No items of noncompliance were identified.

c. Witness of Scram Testing

Both scram tests conducted by the licensee were witnessed by the inspector. The manual scram portion of STP 80-01 was performed on 7/12/80 and the automatic scram portion was performed on 7/13/80. Initial plant conditions at the start of both tests were 10% full power, 940 psig, 520°F and 57 out of 89 control rods fully withdrawn (51 out of the 57 were monitored for scram times). For each test, the inspector verified intial conditions and prerequisites were satisfied, the test recorders were set up, calibrated and functioning prior to the start of the test; and, the test was conducted in accordance with the procedure. The inspector also observed pre-test briefings conducted with the test crew. During the conduct of the tests at the time of the scrams, the inspector was in the control room and verified that all rods inserted in less than 10 seconds, no rods appeared to "hang up" or move in slowly, and the scram header vent and drain valves closed. Additional details on the test results are discussed below in paragraph 10.e.

d. Witness of Scram Discharge Volume Ultrasonic Test Measurements for Standing Water Level

The licensee developed a UT measurement procedure to determine the level of free standing water in the scram discharge volume

(SDV) headers. The procedure was used by the licensee to monitor for residual water level in the SDV starting on July 5, 1980 and daily thereafter, including additional measurements that were taken prior to, during and immediately after the July 12-13 scram testing. The inspector witnessed the UT masurements made at various times throughout the period of interest, as well as the UT equipment setup and periodic checks conducted using a calibration standpipe.

No water accumulation was found in any portion of the SDV during the pre-scram test measurements. Additional measurements taken following the manual scram and both before and after the automatic scram revealed no water accumulation, except for a small amount in a portion of the 6 inch discharge header. The water was first noted following the manual scram and the same amount of water was found during measurements made before and after the automatic scram. The water accumulated at position designated N-2 in the licensee's UT procedures; this location was later confirmed by measurement to be at a lower point than the two inch drain line from the North header to the SDV instrument volume. A maximum water depth of 0.8 inches (in a six inch diameter pipe) was found at location N-2 which tapered out to a depth of zero inches at a distance of six feet in both directions from the point of maximum depth. The water represents 0.3% of the total volume available in the North SDV header. This small amount of water is of little significance and does not impair the safety function of the SDV, as verified by the fact that no significant differences existed in scram system response between the manual and automatic scram tests. Following scram reset, the water eventually evaporates, which explains why no water was detected at position N-2 prior to the scram tests.

The inspector had no further comments on this item at the present time.

e. Scram Test Data Review

The inspector reviewed data and results from both scram tests reported by the licensee on July 18, 1980. Test results were independently reconstructed from the raw data and found in agreement with the licensee's conclusions. Test data reviewed included the following parameters:

-- Control rod scram times (51 rods);

-- Scram solenoid scram bus voltage;

-- Scram valve air header pressures;

-- Scram instrument volume fill time;

-- Vent and drain valve opening and closing times;

-- Delay time from scram to full closure of vent and drain valves;

-- Chemical analysis (suspended solids) of scram discharge volume water;

-- SDV drain time;

-- Results of UT examination;

-- Reset time of scram reset timer; and,

-- SDV pressure variation with time.

The findings of the above review were as follows:

(1) Comparison of data sets from both the manual and automatic tests shows little, if any, significant difference in scram system response. Scram times for each test were compared with test results from previous startup scram testing and were found within normal expected ranges. Overall system response and subcomponent response was as expected (except as noted below).

(2) To verify that all water was drained from the 6 inch volumes and there was no additional water flowing into the SDV from drives, the vent and drain valves were closed for 15 minutes following the manual scram tests with the SDV depressurized. The Instrument Volume Hi level alarm point (3 gallons) was monitored and verified not to alarm, indicating no water accumulation in the instrument volume.

(3) Following this check, two rods on the south bank of HCUs (farthest from the instrumented volume) were scrammed from position 00. Both the level instrumentation on the instrument volume as well as the UT device on the 6 inch headers (south side) were monitored to determine if any water accumulation was taking place. After 15 minutes no water accumulation was evident at either point. The drain and vent valves were then closed to verify that water from these drives was actually flowing into the system. This was verified by the Hi alarm (3 gallons) which tripped 1 minutes and 18 seconds after closure of the drain and vent valves.

(4) During the manual scram, the UT device was set up on a point in one of the 6 inch pipes (south side) to monitor water level in this piping during the scram. Due to turbulance in the piping and failure of the transducer, no data could be gained as the volume filled. After the scram was reset, water level in the piping was again monitored as it drained with the following results:

Time after reset	Water level in 6 inch pipe
1 minute, 10 seconds	6 inches
5 minutes, 45 seconds	4.5 inches
10 minutes	0 inches

As level was not monitored continuously, the exact point in time that level decreased below 6 inches and reached 0 inches could not be determined more accurately. The time from reset to clearing of the three gallon alarm in the instrument volume was 4 minutes. The data indicates the following:

-- The instrument volume drains faster than the 6 inch headers.

-- The clearing of any of the instrument volume switches following a scram is not an indication that all volumes are drained and the system is capable of functioning properly in the event of another scram. Proper draining of the system and therefore proper functioning during a scram occurs 10 minutes after scram reset or 6 minutes after all level alarms on the instrument volume have cleared.

-- The UT check for water in the SDV overhead piping is a necessary pre-requisite prior to restarting the plant after a scram.

The startup pre-requisite check list, OP 0100, was changed by DI 8044 to require UT measurements for SDV residual water be made prior startup.

(5) SDV pressure was monitored as a functin of time during both the manual and auto scram. Only pressure in the instrument volume was measured as no taps existed in the 6 inch header. Both tests results showed about equal response. Pressure started increasing slowly, then rapidly and steadily increased to reactor pressure 2 minutes after the manual scram and

remained stable. Pressure decayed to 0 psig 30 seconds after the scram was reset.

(6) Prior to conduct of the scram testing, the licensee was notified by GE that, when draining the SDV instrument volume after the test, the float switches may momentarily indicate falsely that the instrument volume has drained. It is postulated that this is caused by an air plug that comes through the system and permits the level floats to drop momentarily. This was observed to occur in both the manual and auto scram tests at VY with the instrument volume hi level (3 gallons) alarm switch only. In both tests, the alarm erroneously cleared 15 seconds after scram reset. The switch then returned to an alarm (correct) condition 30 seconds later. The instrument hi level alarm correctly cleared in both tests 4 minutes after the scram was reset.

The inspector had no further comment on this item at the present.

f. System Walk Down

The resident inspector conducted a walk down of accessible SDV piping to verify the following:

-- Drawing G-19170 accurately reflected the as installed system with respect to principle design features;

-- no problems were evident associated with interconnections with other plant system;

-- no loop seals were present; and,

-- drain slope was correct over the entire piping run for both the North and South headers.

No physical measurements of piping slope were made by the inspectors; however, the inspectors did confirm by observation that the SDV piping slopes toward the SDV instrument volume over those portions inspected (with exception to location N-2 as discussed above). However, a portion of the South header 2 inch drain line passes through the Main Steam tunnel and this section of piping was not inspected. This item will be examined on a subsequent inspection when the Main Steam tunnel area is accessible (50-271/80-10-05).

g. Procedure Review

The inspector reviewed licensee procedures to verify that procedural requirements, regarding licensee actions should all control rods

fail to insert during a scram, either met or exceeded the guidelines established by IEB 80-17. The following procedures were reviewed:

-- OP 2114, Operation of the Standby Liquid Control System
-- OP 3100, Reactor Scram
-- OP 3130, Inability to Shutdown with Control Rods

No inadequacies were identified.

h. SDV Daily Checks Prompt Notification, 10 CFR 50.59 Review, and ATWS Analyses

(1) SDV Daily Checks

The inspectors verified, by conducting periodic checks, tha the special UT measurements to detect residual water in the SDV were conducted daily by the licensee during plant operation at power.

(2) Prompt Notification

The licensee has committed to promptly notify (within 24 hours) the NRC:RI when any of the following systems are less than fully operable:

-- Isolation Condenser;

-- Containment Spray System;

-- Standby Liquid Control System; and,

-- Main Steam Bypass System.

(3) 10 CFR 50.59 Review

The licensee conducted a safety review of the Standby Liquid Control System (SLCS) in an effort to determine if modifications could be made to the system, under 10 CFR 50.59 provisions, to increase system flow by allowing two (2) pump operation. The results of that review indicated that modifications to increase system flow should not be accomplished under 10 CFR 50.59.

(4) ATWS Analysis

The licensee, in conjunction with GE, reported on 7/31/80 the results of transient analyses for (i) a generic bounding

case for MSIV closure with scram of all rods in a 180 degree sector of the core; and, (ii) a VY plant specific case for turbine trip with bypass and no scram. The results of the analyses showed that no plant derate is required to meet the 1500 psig reactor pressure vessel limit. It was further concluded that continued operation of VY without ATWS RPT was not an unreviewed safety question and does not produce a safety hazard to the general public.

i. Operability of the SDV Vent Paths

The inspector witnessed modifications made to the SDV vent system on 7/21/80 that would make the vent system effective regardless of component operability other than the vent valve. This was accomplished under PAR 80-45 (and RWP 00657) by removing the internals of check valves in line between the vent valves (32A and 32B) and the ventilation header. This action created an open path through the vent valves to the reactor building ventilation exhaust plenum.

The inspector had no further comment on this item.

j. Supplemental Operator Guidelines

The inspector verified through reviews of procedures OP 211, 2114, 3130 and 3100 that guidelines were promulgated to the licensee operators to cover the following:

-- remedial action to be taken should water be found in the SDV at times when it should be free of water;

-- provision for ready access to the SLCS key, which is available in the switch key lock at all times;

-- instructions to intiate the SLCS should: (i) a gross failure of control rods occur and it is apparent they cannot be moved under hydraulic pressure; (ii) normal rod exercise indicates a rod is stuck such that shutdown margin requirements cannot be met; (iii) the reactor enginer determines the shutdown margin cannot be met; or, (iv) reactor water level cannot be maintained or torus water temperature cannot be maintained and the CRD system is unable to maintain the reactor subcritical as indicated by the neutron monitors.

The VY procedures state that the control room operator will initiate the SLCS, with shift supervisor approval, should any of the aforementioned conditions developed. Based on inspector observations and discussions with licensee personnel, the shift

supervisor is normally stationed in the control room and thus readily available to acknowledge initiation of SLCS operation without undue administrative delay. Further, per AP 0150, Revision 13, the control room command function is transferred to the senior control room operator during shift supervisor temporary absences.

The inspector had no further comment on this item at the present time. Licensee actions in regard to IEB 80-17, as documented in responses submitted through 8/11/80, are deemed acceptable. NRC staff review of BWR scram systems and further VY actions in regard to IEB 80-17 will be covered on subsequent inspections in this area.

11. Backup Scram Valve Operability

Information received at the NRC:VY Site Office indicated that probelsm had been identified at some BWR facilities that rendered the backup scram valves inoperable. Specifically, it was found that solenoid operators for the valves were rated for 250 VDC operation while they were in fact powered by a 125 VAC supply. The inspectors interviewed licensee personnel, inspected the backup scram valves and reviewed drawing B191301, sheet 823 to determine that both backup scram valves at VY are ASCO valves (wplbx 831636) rated for 115 VDC operation and are powered by 115 VDC.

The inspector had no further comments on this item.

12. Diesel Generator Air Start Modifications

A 10 CFR Part 21 report received by the NRC (80-218-000) revealed vendor identified problems associated with air start system modification packages supplied for Fairbank Morse diesel generators. The inspector verified by record review that the air start modification package for the Emergency Diesel Generator had not been installed at VY. The licensee stated that VY PDCR 77-01, Improved Diesel Air Start procedure, was to be cancelled by a memo to the Plant Operations Review Committee. This modification was originally listed in 1980 VY Design Changes, Revision No. 3, effective 7/1/80. The inspector provided a copy of subject Part 21 report to the licensee for information. The licensee stated he would include the report into the cancelled procedure package for any further reference to the modification.

The inspector had no further comment in this area at this time.

13. Location of Essential Load Centers

A temporary instruction dated 7/24/80, Location of Certain Load Centers, required a survey be made of operating power plants to assure that all relevant load centers are located in conformance with the NRR Technical Position. The NRR Technical Position requires that any valve which is rquired by Technical Specifications to be locked in a particular position during operation and requires entry into containment to unlock the valve locking capability, should have its locking capability located outside of containment where access can be provided. The inspector interviewed licensee personnel and reviewed Drawings 5920-4 through 5920-16 to determine the locations of motor control centers of Vermont Yankee. Based on this review, the inspector determined that no load centers are located within the drywell that must be accessed during shutdown operations to control valve positions.

The inspector had no further comments on this item. No inadequacies were identified.

14. Review of Licensee Event Report

The inspector reviewed licensee event report LER 80-24 to verify that:

-- the report accurately described the event;

-- the safety significance of the report was as reported;

-- the report was accurate as to cause;

-- the report satisfied requirements with respect to information provided and timing of submittal;

-- stated corrective action was appropriate to correct the cause; and,

-- testing of redundant systems was conducted as required by the Technical Specifications (reference: shift supervisor log entries for 7/18/80).

No items of noncompliance were identified.

15. Plant Operation Review Committee (PORC) Activities

The inspector reviewed PORC Minutes for meetings 79-03 through 80-18 to verify that the PORC was discharging its functions as prescribed by Technical Specification 6.1.A.6. Specifically, the inspector determined that:

-- quorum requirements were met;

-- monthly meeting frequency requirements were satisfied;

-- the committee reviewed maintenance, normal, abnormal and emergency operating procedures and changes thereto;

-- proposed tests, changes to the facility and Technical Specification changes were reviewed;

-- instances of violations of the Technical Specifications were reviewed (reference: Inspection Reports 79-03, 79-10, 79-11, 79-12, 79-14, 79-17, 80-03, and 80-06);

-- the PORC functioned to determine whether proposals submitted to it constituted an unreviewed safety question.

Except as noted below, the inspector had no further comments on this item.

For those meeting minutes reviewed starting about August, 1979 through the present, the inspector noted that proposed Technical Specification changes and plant modifications reviewed by the PORC contain a statement that they do not constitute an unreviewed safety question as addressed in 10 CFR 10.59(a)(2), based on the written bases presented, and were forwarded to the Plant Superintendent recommending approval or disapproval. Written documentation of these items is required by Technical Specification 6.1.A.7. Prior to August, 1979, this was not addressed in the PORC minutes. In that the PORC appears to be now functioning in accordance with the requirement, the inspector had no further comments in this area at the present.

16. Problem Identification Reports

Plant information reports (PIRs) were reviewed by the inspector to:

-- inspect for trends or recurring failures; and,

-- determine whether the licensee was resolving identified discrepancies involving safety related components.

PIRs 76-1 to 76-17, 77-1 to 77-4, 78-1 to 78-3 and 79-1 to 79-4 were reviewed, along with applicable portions of PORC minutes covering meetings 78-1 through 80-18. The inspector identified no instances of trends or uncorrected failures. Additionally, the inspector verified that PORC reviews of the problems identified by the reports included determinations whether an unreviewed safety question was involved pursuant to 10 CFR 50.59(a)(2).

No items of noncompliance were identified.

17. Licensee Plans for Employee Strikes

The licensee learned on July 21, 1980 that a union picket might be set up outside the plant main gate and, if established, plant union personnel might honor the picket line. The inspector interviewed licensee personnel to determine what plans and procedures were developed by the licensee to assure continued safe operation of the plant. Items considered during this review included the following:

-- a determination of the number of people that would be involved with a work stoppage and which departments would be affected;

-- a determination of whether plant staffing during a strike would meet regulatory requirements in the areas of plant management, operations, maintenance, chemistry, radiation protection, security and fire brigade members;

-- the need for training or refresher training of those individuals who may be called upon to conduct licensed activities for which they are not normally assigned;

-- whether strike plans assured continued availability of facility supplies, such as diesel fuel;

-- whether offsite ambulance and support agencies would continue to be readily available;

-- whether local law enforcement agencies had been notified and were prepared to respond to civil disorders;

-- whether emergency communications equipment would remain available; and,

-- whether onsite and off-site staffing would be sufficient to implement the emergency plan.

The inspector determined that the licensee was prepared to meet the requirements outlined above. Supplemental training was given to plant non-union personnel to upgrade the qualifications of five individuals to meet fire brigade staffing requirements. Technical Specification requirements for an individual qualified in health physics procedures were met by supervisory, non-union staff members. Minimum staffing requirements for the operations crew were met by a staffing schedule (reference: Operations Supervisor internal memorandum dated 7/22/80) using 18 licensed supervisory personnel. The inspector reviewed course outlines and attendance records for those individuals who received fire brigade training.

No items of noncompliance were identified.

19. Observations of Physical Security

The inspector made observations, witnessed and/or verified during regular and offshift hours that selected aspects of plant physical security were in accordance with regulatory requirements, the physical security plan and approved procedures.

a. Physical Protection Security Organization

-- inspector observations indicated that a full time member of the security organization with authority to direct physical security actions was present as required.

-- manning of all shifts on various days was observed to be as required.

b. Physical Barriers

-- selected barriers in the protected area and vital area were observed and random monitoring of isolation zones was performed. Observation of vehicle searches were made.

-- alterations to the gatehouse #2 structure and established compensatory controls were monitored.

c. Access Control

Observations of the following items were made:

-- identification, authorization and badging;

-- access control searches, including the use of compensatory measures during periods when equipment was inoperable; and,

-- escorting.

Except as noted below, no inadequacies were identified and the inspector had no further comments in this area.

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20. Exit Interview

'anagement meetings were held with licensee personnel (denoted in paragraph 1) at various times throughout the inspection period. The inspection scope and findings were discussed as they appear in the details of this report.