50-271/80-06-11
50-271/80-10-14
50-271/80-10-27
50-271/81-01-01
50-271/80-12-29
79-12-07
80-07-18
79-11-08
79-09-02

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

Region I

Report No. 80-22

Docket No. 50-271

License No. DPR-28 Priority -- Category C

Licensee: Vermont Yankee Nuclear Power Corporation
1671 Worcester Road
Framingham, Massachusetts 01701

Facility Name: Vermont Yankee

Inspection at: Vernon, Vermont

Inspection conducted: November 17, 1980 - January 3, 1981

Inspectors: William J Raymond — 2/23/81
W.J. Raymond, Senior Resident Inspector — date signed

William J Raymond for — 2/23/81
S.J. Collins, Resident Inspector — date signed

date signed

Approved by: Robert M Gallo — 3/16/81
R. M. Gallo, Chief, Reactor Projects Section 1A, Projects Branch #1 — date signed

Inspection Summary:

Inspection on November 17, 1980 - January 3, 1981 (Report No. 50-271/80-22)

Areas Inspected: Routine, unannounced inspection on regular and back shifts by the Resident Inspectors of the status of previous inspection findings; plant operations, including record reviews and facility tours; operational safety verification of the facility prior to startup from refueling outage; core load activities and core load verification; emergency planning, including procedure revisions (IAL 80-34), instrument calibrations and conduct of annual EP Drill; refuel maintenance activities; refuel outage modifications, including RPT/Analog Trip System installation; RWCU material conformance to NUREG 0313 (IAL 80-51); followup of plant events, including plant trip during startup, MSIV malfunctions and RWCU system leakage outside the Drywell; followup on IE Bulletin 79-02 (TI 2515/28) and Bulletin 79-14 (TI 2515/29); review of surveillances, including the Type A CILRT; and, review of training sessions. The inspection involved 192 inspection hours onsite by two Resident Inspectors.

Results: Of twelve areas inspected, no items of non compliance were observed in eleven areas; one apparant item of non compliance was observed in one area (failure to adhere to TS 6.5.D requirements when changing an approved procedure, paragraph 12.d).

Region I Form 12
(Rev. April 77)

8105290391

DETAILS

1. Persons Contacted

Vermont Yankee Personnel

Mr. W. Anson, Plant Training Supervisor
Mr. J. Arensmeyer, Technical Assistant
Mr. B. Ball, Technical Assistant
Mr. P. Donnelly, Instrument and Control Supervisor
Mr. H. Hymes, Instrument and Control Engineer
Mr. S. Jefferson, Reactor Engineering Supervisor
Mr. R. Lopriore, Engineering Assistant
Mr. R. Leach, Health Physicist
Mr. T. Lynn, Training Coordinator
Mr. M. Lyster, Operations Supervisor
Mr. B. Metcalf, Shift Supervisor
Mr. R Mossey, Technical Assistant
*Mr. W. Murphy, Plant Superintendent
*Mr. J. Pelletier, Assistant Plant Superintendent
Mr. D. Reid, Engineering Support Supervisor
Mr. S. Vekasy, Senior Mechanical Engineer
Mr. B. Webber, Senior Electrical Engineer
Mr. D. Weyman, Chemistry and Health Physics Supervisor
Mr. W. Wittmer, Maintenance Supervisor

Mercury Company Personnel

Mr. J. Duguay, QA Supervisor
Mr. J. Ohleyer, QC Technician
Mr. M. Trombley, Project Manager

The inspectors also interviewed other licensee personnel during the inspection, including members of the Operations, Health Physics, Maintenance and General Office staffs.

(* denotes those present at periodic management meetings)

2. Status of Previous Inspection Findings

(Closed) Inspector Follow Item (50-271/80-08-01): Primary Coolant Leakage Deflectors. The inspector noted during a drywell inspection tour on December 23, 1980, that installation of primary coolant leakage deflectors per EDCR 80-36 was complete. Deflector plates were bolted/tac welded to the 252 foot elevation grating beneath the following penetrations/process lines: X13A/RHR 31; X12/RHR 32; X13B/RHR 30; X9B/FDW 29B; and, X9A/FDW 29A. The deflector plates were positioned such that potential leakage from the subject lines would be deflected away from the drywell to torus vent headers and be collected by the drywell floor drains sump. The modifications conclude licensee actions in regard to LER 80-18 and allow relaxation of the reduced administrative limits imposed on identified and unidentified leakage rates. This item is closed.

(Closed) Inspector Follow Item (50-271/80-15-07): Environmental Qualification of Stem Mounted Limit Switches. The inspector noted by review of licensee report YAEC-1228, Environmental Qualification of Safety Related Electrical Equipment dated October, 1980, that a description of stem mounted limit switches used on safety related electrical equipment was included in the material presented. Tab 19 of Appendix II provided the environomental qualification worksheets for the NAMCO EA-740-86700 limit switches used on the AOV-2-86 series and AOV-2-80 series isolation valves. The material presented was consistent with previous NRC inspection findings in this area. This item is closed.

(Closed) Unresolved Item (50-271/80-16-02): Loose Parts Analysis for Core Spray Sparger Cracking. The inspector reviewed the licensee's evaluation presented in a November 13, 1980, GE letter, G-HB-0-117, Loose Piece and ECCS Analysis for Core Spray Junction Box "C". The loose parts analyses presented the bases, probabilities and consequences of generating loose parts from the sparger clamp plugs, the clamp locking plug and the junction box port plug. The analysis considered the dimensions of the potential parts, the dimensions of critical reactor internal components, impact on channel flow blockage and effects on the fuel MCPR. Similar considerations were applied to the analysis of loose parts impact on control rod operation. The analysis concluded that the probability for adverse consequences from postulated loose parts was essentially zero. No inadequacies were identified by the inspector. This item is closed.

(Closed) Unresolved Item (50-271/80-15-06): Broken Flexible Conduit on MOV-23-15. The inspector noted during an inspection tour of the drywell on December 23, 1980 (see paragraph 3) that the conduit on MOV-23-15 had been repaired. This item is closed.

(Closed) Inspector Follow Item (50-271/80-15-16): Plant Emergency Procedures, IAL 80-34. The inspector noted by review of approved procedures on December 12, 1980, that emergency operating procedures (EOP) had been revised in accordance with the requirements of the NRC Region I letter to the licensee dated October 3, 1980 (IAL 80-34). The inspector also reviewed training class rosters for training given on the revised EOPs on November 18 and November 20, 1980. The inspector also attended the November 20, 1980, training class. The class worked from VYOPF 3125.01

to provide instructions on conducting dose assessments and initial assessment of emergency classifications.

This item is discussed further in paragraph 5 of this report. IAL 80-34 requirements have been satisfied. This item is closed.

(Closed) Inpsector Follow Item (50-271/80-17-02): Penetration Fire Barrier Seals. The inspector met with site management on November 27, 1980, to discuss VY actions to resolve concerns raised with penetration fire barrier seals. The inspector stated that the VY position on the 3 hour rating of penetration fire barrier seals, as related to recent fire testing completed by the Chemtrol Corporation, should be formally documented in a submittal to NRC:NRR. The course of action planned to evaluate the adequacy of penetration seals should also be specified. Finally, the licensee should also include in the submittal to NRC:NRR a description of the methods by which penetration fire barrier seals will be replaced and/or upgraded to 3 hour fire ratings, assuming the results of the proposed evaluations do not prove the adequacy of the penetrations. The licensee adknowledged the inspectors comments. Licensee actions in this area remain outstanding.

However, the above NRC positions were reiterated to the licensee during a special inspection conducted on December 2-4, 1980, and are designated as unresolved item 50-271/80-18-03. In that item 80-18-03 is sufficient to track licensee actions on this item (and other issues raised during Inspection 80-18), Inspector Follow Item 50-271/80-17-02 is considered closed.

(Closed) Unresolved Item (50-271/80-17-05): Pressure Indication for the Scram Pilot Air Header. By letter dated December 3, 1980, the licensee revised his response to IE Bulletin 80-17, Supplement 3, Item 1.a and reported that OP 2111 had been revised to provide for an immediate manual scram of the reactor for conditions of low scram pilot header air pressure based on a pressure indication mounted on the control board. The inspector noted on December 18, 1980, (prior to plant startup) that remote pressure indication from PI-3-229 was displayed on CRP 9-5. The inspector noted the CRP 9-5 indicator read 75 psig with the scram pilot air header pressurized. The inspector also observed the CRP 9-5 indicator reading following a reactor trip on December 24, 1980, and noted that it read zero psig with the scram pilot header depressurized. This item is closed.

3. Review of Plant Operations

Reactor and plant system operations were reviewed during the inspection period to verify conformance with procedural and Technical Specification requirements. Operational activities in progress during the inspection period included: reactor defueled and reactor vessel partially drained to support reactor water cleanup (RWCU) system repair; non-isolable portions of RWCU system repairs complete, reactor vessel filled and reactor cavity flooded to refuel level - 12/8; core reload started - 12/9; core reload complete - 12/13; reactor vessel cold hydrostatic test complete - 12/18; Primary Containment Type A leak rate test complete - 12/21; plant startup from 1980 refuel outage with reactor critical at 7:50 PM - 12/23; reactor vessel hot hydrostatic test complete - 12/28; main generator tied to electrical grid - 12/28; plant power held at 25% FP; leak discovered on RWCU system between regenerative and non-regenerative heat exchangers - 12/29; reactor power decreased and mode switch put into STARTUP position for MSIV repair work - 1/2; RWCU system pipe leaks and MSIVs repaired - 1/3; and power operation resumed under fuel preconditioning limits - 1/4. Areas inspected during this period are summarized below.

a. Instrumentation

Control room process instrumentation was observed for correlation between channels and for conformance with Technical Specification requirements. No unacceptable conditions were identified.

b. Annunciator Alarms

The inspector observed various alarm conditions which had been received and adknowledged during the inspection period. These conditions were discussed with shift personnel, who were knowledgeable of the alarms and actions required. During plant inspections, the inspector observed the condition of equipment associated with various alarms. No unacceptable conditions were identified.

c. Shift Manning

The operating shifts were observed to be staffed to meet the requirements of Technical Specifications Section 6 both to the number and type of licenses. Control room and refueling shift manning were observed to be in conformance with Technical Specification and site administrative procedures.

d. Radiation Protection Controls

Radiation protection controls in effect were inspected. Radiation Work Permits (RWPs) in use were reviewed and compliance with those documents, as to protective clothing and required monitoring instruments, was inspected. Proper posting of radiation, high radiation and contaminated areas was reviewed, in addition to verifying adherence to requirements for wearing appropriate personnel monitoring devices. No inadequacies were identified in the areas reviewed. The inspector also reviewed radiation protection controls in effect for the following specific jobs.

(1) Refuel Operations

Controls and health physics coverage for core reload operations were inspected on December 12, 1980, and were found to meet the RWP requirements. Inspector review of the RB 345 foot elevation continuous air monitor results for particulate, iodine and noble gas activity showed no change from previous low activity levels (essentially background). No inadequacies were identified.

(2) Exposure Control - RWCU System Repair

Repairs and replacement of RWCU system piping inside the drywell constituted the most limiting job of all other outage work activities for personnel exposure considerations. The total man-Rem expended for the work is estimated to be about 250 man-Rem. The number of personnel assigned to the RWCU work on a daily basis ranged from 50-66 workers, drawn from a contractor work force of about 200. Due to the potential for individual exposure to be at or near the 10 CRF Part 20 quarterly limits, particular attention was given to a review of drywell entry controls and individual accumulated exposures while RWCU system work was in progress.

Specific review of RWCU work force individual accumulated exposures was completed on December 1 and December 2, 1980. RWP 1728 and 1698 exposure record sheets, along with VY Daily Exposure Logs for November 29, November 30, December 1 and December 12, 1980, were used to verify that quarterly limits were not exceeded. No instances were found in which licensee administrative limits (set lower than the 10 CFR Part 20 limits) were exceeded. No items of noncompliance were identified.

The inspector had no further comment in this area.

e. Plant Housekeeping Controls

Storage of materials and components with respect to prevention of fire and safety hazards was inspected. Plant housekeeping was evaluated with respect to controlling the spread of surface and airborne contamination. The general state of housekeeping was noted to be consistent with the scope and nature of outage maintenance activities. The return to normal/optimal cleanliness conditions was noted to occur as outage work activities ceased. No unacceptable conditions were identified.

f. Fire Protection/Prevention

Selected pieces of fire fighting equipment, including the status of portable fire extinguishers, were noted at various times during inspection tours of the facility. Combustible materials were being controlled and were not found in vital areas. The inspector noted in particular the switchgear/cable vault areas and the main safeguard penetration area on the RB 252 foot elevation, NW corner and found these areas clean of combustibles. No items of noncompliance were identified.

g. Equipment Control

Plant equipment under control of safety tags was selected for review. Tags issued under Switching and Tagging Order No. 4440 were found attached to the appropriate equipment, as indicated below:

MCC 89B	RHR V10-27B	Bkr Open
MCC 89B	RV V2-53B	Bkr Open
MCC 89B	RV V2-66B	Bkr Open
MCC 89B	RV V2-54B	Bkr Open

Equipment conditions were consistent with the requirements specified by control room logs and OP 1121. No inadequacies were identified.

h. Shift Logs and Operating Records

The inspector reviewed the following logs and records on a sampling basis during the inspection: logs were reviewed for the period November 17, 1980 through January 4, 1981.

-- Night Order Book

-- Shift Supervisors Log

The logs and records were reviewed to verify that entries are properly made; entries involving abnormal conditions provide sufficient detail to communicate equipment status, deficiencies, corrective action, restoration and testing; records are being reviewed by management; operating orders do not conflict with the Technical Specifications; logs and incident reports detail no violations of

Technical Specifications or reporting requirements; logs and records are maintained in accordance with Technical Specification and Administrative Control Procedure requirements.

i. Drywell Closeout Inspection

On December 23, 1980, the inspector conducted a tour of the drywell with licensee personnel. The inspector verified by observation that the licensee had corrected the HPCI-15 valve cable conduit break noted in a previous inspection (50-271/80-15). This item is considered closed.

The inspector and licensee personnel noted overall condition of the equipment in the drywell, progress of house cleaning from the 1980 fall refueling outage and inspected for obvious leaks from the closed cooling water system. No unacceptable conditions were noted. Drywell cleanliness was noted to be exceptionally good following the RWCU system repair program.

No items of noncompliance were identified.

j. Reactor Startup

The inspectors monitored licensee actions and preparations for startup of the plant following completion of RWCU system repairs. Inspector review included a verification, on a sampling basis, that startup prerequisites were completed, as specified by VYOPF 0100.03. Inspector review also included an independent verification of plant system valve lineups, as discussed in paragraph 4 of this report.

On December 22, 1980, the inspectors mointored licensee performance of shutdown margin and in-sequence critical checks in accordance with VYOP 0100, Revision 11, November 26, 1980. The inspectors reviewed the procedure with operations and reactor engineering department personnel and verified performance of WYOPF 0100.03 in-sequence critical prerequisite list.

Following completion of the shutdown margin and in-sequence critical checks the inspectors reviewed the data forms for completeness and accuracy.

No items of noncompliance were identified.

k. Power Ascension

The inspector reviewed the sequence of reactor startup and power ascension to full power which occurred during the period from

January 3 to January 5, 1981. The review was conducted through discussions with licensee personnel; observations of plant systems status from control panel indications on January 4 and 5, 1981; and review of operating shift logs. The inspector noted the following during the review:

+ ECCS systems, as observed from control room panel indicators, were properly aligned for standby operation.

+ Normal plant electrical systems and the standby diesel generators were properly aligned.

+ Nulcear instrumentation was operational.

+ Area and process radiation monitoring instrumentation was operational.

+ Meteorological instrumentation was operational.

+ New annunciator/alarm windows associated with recently installed equipment (scram discharge header levels and the RPT/ARI system) were functional in alarm panels A-6 and A-5-A. Alarm procedures for the new annunciators were found available in the control room.

+ Power ascension was under the control of fuel pre-conditioning limits with Reactor Engineering Department personnel providing assistance to plant operators during the evolution. MFLCPR values and limits with the reactor at 1166 MWt (73.2%FP) were discussed with the Reactor Engineer.

No inadequacies were identified.

4. Operational Safety Verification

A detailed review was conducted of the Core Spray (CS) and Residual Heat Removal (RHR) systems prior to plant startup on December 23, 1980. The review was conducted to verify that the systems were properly aligned and fully operational in the standby mode. Review of the CS and RHR systems included the following:

a. Verification that system valve lineups were consistent with valve lineup procedures. OP 2123 and OP 2124 were used to verify the CS and RHR lineups, respectively.

b. Walkdown of the systems to verify that the positions of accessible and normally inaccessible valves in the flow path were correct by direct observation of the valve or the remote position indication.

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 for system actuation and performance was operational.

No inadequacies were identified.

Normally inaccessible valves were reviewed for proper positioning during this inspection. Positions for the following valves were verified:

+ CS-14A (LO)	+ RHR-78B (S)
+ CS-14B (LO)	+ RHR-79A (S)
+ CS-30A (LS)	+ RHR-79B (S)
+ CS-30B (LS)	+ RHR-84 (S)
+ SLC-1B (LO)	+ RHR-85 (S)
+ RHR-78A (S)	+ RHR-193A (S)
+ RHR-193B (S)	+ RHR-100A (S)

Piping hangers and snubbers were also review for proper operation. Items inspected included the snubbers for valve RWCU V14C and the following:

+ MS-34	+ MS-12
+ FW-20	+ MS-23
+ FW-7	

No items of noncompliance were identified.

5. Emergency Planning

Revisions to emergency and emergency operating procedures, RM-14 detector calibration techniques and the conduct of the annual emergency drill were reviewed. Findings are summarized below.

a. Emergency Operating Procedure Revisions and Training

The procedures listed below were approved and issued on the dates indicated. The procedures were reviewed and were found to be consistent with the requirements of the NRC Region I letter to the licensee dated October 3, 1980 (IAL 80-34).

+ OP 3100, Reactor Scram, Revision 9, July 11, 1980

+ OP 3101, Loss of Fuel Pool Level, Revision 1, November 26, 1980

+ OP 3103, Loss of Normal Power, Revision 6, November 26, 1980

+ OP 3107, Loss of Switchgear Room or Cable Vault, Revision 1, November 26, 1980

+ OP 3108, Loss of Containment Integrity, Revision 1, November 24, 1980

+ OP 3109, Anticipated Transient Without Scram, Revision 1, November 26, 1980

+ OP 3112, Loss of Feedwater, Revision 3, November 24, 1980

+ OP 3115, Loss of Shutdown Cooling, Revision 3, November 26, 1980

+ OP 3116, Loss of Reactor Coolant, Revision 11, November 26, 1980

+ OP 3117, Containment High Pressure, Revision 8, November 26,1980

+ OP 3120, High Off Gas Release Rates, Revision 5, November 13, 1980

+ OP 3121, Fuel Element Failure, Revision 8, November 26, 1980

+ OP 3122, Excessive Radiation Levels, Revision 7, November 26, 1980

+ OP 3123, SJAE Rupture Diaphragm Failure, Revision 4, November 24, 1980

+ OP 3124, Loss of Reactor Coolant Outside Primary Containment, Revision 3, November 26, 1980

+ OP 3131, Shutdown from Outside the Control Room, Revision [illegible], November 24, 1980

+ OP 3001, Local Emergency, Revision 9, December 11, 1980

+ OP 3002, Site Emergency, Revision 10, November 7, 1979

+ OP 3003, General Emergency, Revision 12, December 11, 1980

+ OP 3013, Initial Evaluation of Offsite Radiological Conditions, Revision 3, November 7, 1979

+ OP 3530, Post Accident Sampling, Revision 1, December 11, 1980

+ OP 3125, Classification of Emergencies, Original, November 26, 1980

No inadequacies were identified in regard to procedure preparation.

The inspector also reviewed the class rosters for training given to all licensed operators, including emergency directors, during the week of November 17, 1980. Training was provided for the revised emergency procedures, revised operating procedures, dose projection and emergency classification assessments, and outage design changes. VYOPF 3125.01 was used as the basis for dose projection training. The inspector attended an emergency training class held on November 20, 1980 and found that the presentations adequately explained the actions required of the emergency directors and proper use of VYOPF 3125.01 Tables. The inspector had no further comments on this item.

Licensee actions in this area were complete prior to plant startup from the 1980 Refueling Outage. The requirements of IAL 80-34 have been met.

No items of noncompliance were identified.

b. Survey Instrument Calibration

Licensee personnel were interviewed and calibration records were reviewed to determine the methods used to determine the counting efficiency for the onsite RM-14 detectors. The detectors would be used (in part) in conjunction with emergency plan implementing procedures (OP 3013, OP 3010) to determine projected offsite I-131 doses following an incident. The following information was reviewed:

+ OP 3013, Initial Evaluation of Offsite Radiological Conditions, Revision 3, November 7, 1979

+ RM-14 (with Eberline 210 "pancake" probe) sample counting results and gamma spectrographic analysis sheets for August 7, August 9 and August 10, 1979.

Based on this review, the inspector noted that:

+ Iodine source samples were obtained from the primary containment atmosphere using a "BANTAM" - Low Vol portable sample system with a CP-200 cartridge tied into the normal containment sample system.

+ Samples were collected at a flow rate of 10 l/min and purged for 15 minutes at 10 l/min.

+ Source decay time between end of sampling and start of counting was incorporated in the analyses. The 15 minute purge time was not incorporated in the decay time; however, this was deemed to introduce an insignificant error in the overall efficiency determination since the purge time constituted a small (3% or less) fraction of the half-lives for the predominant isotopic species.

+ Onsite multi-channel analyzer equipment was used to determine isotopic composition of the source sample, and to compute the isotopic specific and source composite curie concentrations.

+ RM-14 detector efficiency was determined from the ratio of the background corrected RM-14 reading to the corresponding source composite activity. Results from 4 separate analyses were averaged to obtain the final value. the counting efficiency was determined with the assumption that all source activity was attributed to I-131, which would make field determinations of I-131 concentrations based on RM-14 readings conservative (or high) by about a factor of 10. This assumption was used since the RM-14 cannot discriminate between I-131 and other isotopic species in the collected media. (Other portable collection/analysis equipment available onsite can discriminate I-131).

+ The information, tabulated data and instructions provided in OP 3013 to make offsite I-131 dose assessments based on RM-14 readings were found to be consistent with the above.

No items of noncompliance were identified.

c. Annual Emergency Drill

The inspectors observed the conduct of the licensee's Annual Emergency Drill on December 23, 1980. The emergency drill scenario simulated a charcoal bed fire in the Advanced Offgas system with a resultant release of radioactive material to the offsite environs. A site emergency was declared by the shift supervisor and response actions were conducted in accordance with VYOP 3002, Site Emergency, Revision 10, November 7, 1979. The inspectors monitored licensee activities from the control room, the Technical Support Center and the Emergency Operations Facility. Licensee response actions were also audited by Vermont Yankee management and engineering support personnel from the Westboro Office of Yankee Atomic. The drill included involvement by offsite agencies to the point of notification of NRC and State Offices.

Criteria used by the inspectors to judge the adequacy of licensee response actions included consideration of the following:

-- adequacy of emergency plan (EP) implementing procedures and equipment;

-- assessment of staff familiarization with EP implementing procedures and the Emergency Plan;

-- verification that staff actions were conducted in accordance with the Emergency Plan and implementing procedure;

-- assessment of the overall effectiveness of the drill and pre-drill training;

-- assessment of communications and coordinations with offsite agencies;

-- timeliness (less than 15 minutes) in classifying the emergency based on control room indications and drill "symptoms";

-- timeliness (less than 45 minutes) of actions to effect personnel accountability, and,

-- effectiveness in use of Technical Support Center and coordination of offsite monitoring teams.

The inspectors also attended the post drill critique. Inspector comments on licensee performance were presented to plant management. All inspector comments and suggested emergency response improvements were also identified by the licensee's drill auditors. No unacceptable conditions were noted during performance of the drill. Overall, the drill was deemed satisfactory and demonstrated effective emergency response training.

No items of noncompliance were identified.

6. Refueling Activities

Core reload activites were monitored during the inspection. Activities to reload the core began on December 9, 1980 following completion of RWCU repairs and cleanup system operation to improve reactor cavity water clarity. Inspection activies included observations of fuel movement in progress and review of the loaded core for proper fuel assembly positioning.

a. Observations of Fuel Movement

Fuel handling activities in progress on December 9, December 11 and December 12, 1980, were observed by the inspector to verify safe conduct of operations and adherence to established controls. The following was determined through record review and by direct inspector observations:

+ Core reload was accomplished under a modified spiral sequence, with the first 8 assemblies loaded adjacent to the four permanent incore source range mointors (SRMs). This action raised SRM channel output to a value greater than 3 cps.

+ Core loading prerequisites were satisfied, as evidenced by a completed form VYOPF 1410.02 and direct inspector observation of communication channels available and in use; refueling apparatus available and in use; RWPs in effect; spent fuel pool and reactor cavity water level; SRM shorting links removed from the respective terminals; reactor mode switch positioned to REFUEL; availability of TS 3.5.H.4 ECCS systems; and, secondary containment integrity.

+ Refueling interlock functional testing was completed as applicable, per VYOPF 4102.01, inclusive of DI 80-47 on December 8, 1980.

+ An approved copy of OP 1410 was available, in use and maintained. Full status boards in the control room and on the refueling deck were maintained up-to-date.

+ Health Physics coverage was provided in accordance with RWP requirements. Refuel area air activity, as provided by continuous air monitor readings, showed no adverse trends or levels above background readings.

+ Spent fuel pool temperature was observed to be 70°F on December 12, 1980.

+ Refuel floor and control room staffing met procedural and Technical Specification requirements, with a licensed operator dedicated to the CRP 9-5 panel to monitor SRM readings when fuel insertion into the vessel was in progress; and, with a licensed senior operator in charge of fuel handling activities on the refuel floor.

+ Both diesel generators were available in the standby mode, as well as both trains of the standby gas treatment system; and,

+ A review of the REfuel loading and the on-duty HP logs revealed no unusual problems had developed during core loading activities. During discussions with the RE Assistant on duty on December 12, 1980, the inspector learned that a small piece of paint chip (described as 4" by 2") had been observed on the core upper structure. The paint chip came from the separator pit shield blocks installed adjacent to the vessel cavity. Several attempts to retrieve the paint chip proved unsuccessful, in that the chip was light, flimsy and broke into several smaller pieces during removal attempts. The inspector noted that the remnant pieces would either be removed by continued operation of the vessel cleanup system or, would disintegrate during subsequent reactor operation with no probable adverse effects.

No items of noncompliance were identified.

b. Core Load Verification

The inspectors conducted an independent verification of proper fuel configuration by comparing actual fuel assembly position and orientation, as presented by a licensee videotape of the core, with the Cycle 8 Fuel Bundle Orientation Map. The inspectors verified by observation of the videotapes that fuel bundle identification numbers and bundle orientation correspond to the requirements of the approved Fuel Bundle Orientation Map.

No items of noncompliance were identified.

7. Refueling Maintenance - T/G Inspections and Repairs

The turbine generator (T/G) unit was inspected by the licensee during the outage in accordance with routinely scheduled maintenance practices and in order to establish a data base on turbine conditions. Additionally, inspections were conducted in part as a result of concerns and potential generic problems identified in IE Information Notice 79-37. The inspector interviewed licensee representatives and reviewed facility records to determine the nature and scope of T/G inspections and repairs.

a. Turbine Erosion - Wheels

Visual magnetic particle and ultrasonic (UT) inspections of the A and B low pressure turbine wheels was completed. No crack or crack indications were found on the disc sections. Visual and UT examination of the tangential entry wheel dovetails revealed no indications. UT examination of the wheel bores and keyways did show flaw indications. The UT indications were found on the 2-6 wheels of LP A and on the 2-8 wheels of LP B. Visual examination of the same area (i.e., wheels 2-6 of LP A and wheels 2-8 of LP B) showed water cutting/erosion in line with the wheel keyways. The water cutting marks coincide with the locations of the UT indications and are the most probable cause of the UT indications. However, the UT indications were assumed to be stress corrosion cracks for analysis purposes and expected growth rates were calculated. The calculated growth after six years operation was obtained from the present size of the indications and the growth rate in a wet steam environment. The expected crack size in six years was found to be much less than the critical crack depth. Based on this evaluation, the T/G vendor recommended that subsequent T/G inspections be scheduled in 1986. However, the licensee plans to perform additional inspections on a schedule more conservative than that recommended, with the HP turbine scheduled for inspection in 1982 and the LP turbines scheduled for the 1983 and 1984 outages.

No inadequacies were identified.

b. Bearing Wear

The No. 6 turbine bearing had shown higher than normal vibrations during plant operations prior to shutdown. The bearing was inspected during the outage and was found to be wearing unevenly on the journal end. The licensee's initial evaluation for corrective repair considered scraping the bearing on site and shimming the bearing to even out wear. Further review of this corrective action plan showed that the bearing wear pattern would not allow for proper rotor tilt. Thus, the bearing was removed and sent offsite to be machined down. This action corrected uneven wear and provided for proper tilt.

No inadequacies were identified.

c. Cracked Blade

Inspection of the turbine discs and blades revealed a cracked blade in the eighth stage of the A LP turbine. The blade is about

4 inches long. The crack was located in the block to bucket transition point. Although the type of crack identified was not expected, the crack represented an isolated, random failure and was not a precursor to other failures. Further evaluation of the cracked blade is planned by the licensee. The blade was removed along with one on the opposite side of the wheel to maintain symmetry and balance.

No inadequacies were identified.

d. Turbine Erosion - Inner ngs and Pipes

Steam and/or water erosion was also identified in other areas inspected, including the turbine steam headers, the crossover piping and the low pressure turbine inner casings. In areas where the depth of erosion caused the minimum wall thickness to be approached, wall thickness was restored by weld metal buildup. The HP turbine top exiting header pipes were weld repaired as described above. The bottom exiting pipes,consisting of 36 inch diameter, 40 foot long pipes made from chrome-molly with copper bearing material, were replaced with new piping made from nickel bearing material. The new piping is expected to be more corrosion resistant. The HP turbine top exiting header pipes will be replaced during the next refueling outage.

No inadequacies were identified.

Based on the above reviews, the inspector identified no conditions adverse to plant, plant worker or public health and safety.

No items of noncompliance were identified.

8. Outage Modifications

Work in progress and/or completed under plant design modification packages listed below was reviewed during the inspection to verify the work was completed in accordance with approved procedures and regulatory requirements.

a. EDCR 80-36, Primary Coolant Leakage Deflectors

Installation of the leakage deflectors was completed prior to plant startup. In accordance with the EDCR requirements, deflector plates were installed beneath feedwater and residual heat removal lines that have the potential for leakage which could bypass the normal leakage detection systems. Inspector review of the installation verified that the work was completed in accordance with the EDCR specifications.

No inadequacies were identified.

b. EDCR 79-57, PAM Torus Level and Containment Pressure

Modifications completed under this EDCR resulted in the installation of wide range torus level and containment pressure instrumentation. Redundant level and pressure readouts from the instrumentation was added to CRP 9-3. Instrumentation readouts were operational by December 18, 1980. Two channels of containment high range pressure were provided with readouts from PI 16-19-12A, B displaying pressure in the range of 0 to 270 psia. Two channels of torus wide range level were provided with readouts provided from LI 15-19-12A, B displaying water level in the range from 0 feet to 20 feet. Normal torus operating level range was noted on the display from 10.8 feet to 11.5 feet. The inspector observed the readouts during the performance of the Type A containment leak rate test and noted that the wide range instrumentation was consistent with other instrument channels monitoring torus level and containment pressure.

No inadequacies were identified.

c. EDCR 80-02, Containment High Range Radiation Monitors

Work completed under this design change package resulted in the installation of two separate high range containment radiation monitors. The radiation monitors were installed just above the Drywell 252 foot elevation, one on either side of the Drywell Equipment Access Hatch. Readouts from the monitors were mounted on control room panels CRP 9-3 and CRP 9-10, with displays of containment radiation level in the range from zero to 1E+7 R/hr. The monitors were noted to respond upscale during subsequent plant operation, with indicated values of 2.5 R/hr with the plant at full rated power.

Based on a review of the physical installation of the monitors and discussions with the I&C Supervisor, the inspector noted that the cables and connectors to the monitors were environmentally qualified. However, efforts to obtain complete documentation of qualification data are still in progress. The status of environmental qualification of equipment is presently under review by the Office of Nuclear Reactor Regulation.

No inadequacies were identified.

d. EDCR 80-11, 1980 Torus Modifications

Modifications and changes to torus exterior and interior structures were completed during the outage, prior to plant startup. Previous NRC review of this area is documented in NRC Region I Inspection Reports 50-271/80-13, 50-271/80-15, 50-271/80-16 and 50-271/80-17.

Torus internal work was verified complete during a torus closeout inspection on November 13, 1980. The inspector noted during inspection tours prior to plant startup on December 23, 1980, that all work on the torus exterior was complete, including anchoring of torus saddles to the Reactor Building base mat. Housekeeping and cleanliness in the areas toured were also reviewed and found acceptable.

All modifications under the torus long term program have been completed. Verification of the adequacy of the present modifications and a determination of what further modifications, if any, that may be required, will be accomplished through the completion of the VY plant unique analysis.

No inadequacies were identified.

e. <u>EDCR 79-02, RPT/Analog Trip System</u>

Installation of the Recirculation Pump Trip/Analog Trip System proceeded to completion during the inspection period. Installation work and testing in progress were followed by the inspector throughout the period. Inspection review included verification of installations in accordance with the Installation Procedure for EDCR 79-02 - for all work completed as of November 19, 1980; partial testing completed in accordance with the Test Procedure for EDCR 79-02; and, witness of total system testing in progress on December 9, 1980. Findings are summarized below.

(1) Work completed as of November 19, 1980, was reviewed by comparison of the physical installation to the Installation Procedure. The inspector noted that applicable prerequisites had been met and that the official copy of the Installation Procedure was maintained up to date. The inspector noted further that the Installation Procedure also required post installation checks of the equipment that included calibration of the Rosemont transmitters; calibration of bistable trip setpoints; and annunciator circuit continuity verification.

No inadequacies were identified.

(2) Partial system testing completed as of November 19, 1980, included a verification of transmitter calibration and trip system functions. Actual testing was completed during the period of October 29 to November 3, 1980, as noted by review of the Test Procedure. The intent of the partial testing was to verify that all RPS channels that previously received inputs from the Yarway Level Switches and Barksdate Pressure

Switches were returned to a normal state, and that the new analog systems were compatible with the trip system and functioning correctly. The above was accomplished by injecting a test signal at the level/pressure transmitter mounted on the 25-5 and 6 racks, increasing the simulated signal to the trip setpoint and verifying that the trip signal was correctly generated. The latter verification included a check that the appropriate RPS scram relays de-energized; the scram solenoid groups activated and half-scram occurred; and, the appropriate control room annunciators and computer inputs were received.

The inspector reviewed the completed test results documented in the EDCR 79-02 Test Procedure for the following instrument/RPS loops:

Rack 25-5	Rack 25-6
+ PT 2-3-55A/RPS-25-5A	+ PT 2-3-55C/RPS-25-6A
+ PT 2-3-55B/RPS-25-5A	+ PT 2-3-55D/RPS-25-6A
+ LT 2-3-57A/RPS-25-5A	+ LT 2-3-58A/RPS-26-6
+ LT 2-3-57B/RPS-25-5A	+ LT 2-3-58B/RPS-25-6A
+ LT 2-3-72A/ECCS-25-5B	+ LT 2-3-72B/ECCS-25-6B
+ LT 2-3-72C/ECCS-25-5B	+ LT 2-3-72D/ECCS-25-6

The inspector noted for each unit tested that trip occurred at the required setpoint and channel response was correct.

No inadequacies were identified.

(3) Testing in progress on December 9, 1980, was reviewed and observed by the inspector. The inspector noted the prerequisite list for the procedure and that applicable requirements were satisfied. OQAD inspectors were also present to witness testing as required. Instrumentation used in the testing was reviewed for current calibrations. Test instruments included voltmeter VY 483 and heise test guage 32833. Conduct of testing was observed in the control room and at the 25-5 and 6 racks. The inspector also noted that approved copies of the test procedure were available and in use by test personnel and that the test copies included temporary changes incorporated by PORC review on November 26, 1980.

Testing in progress involved several checks and system function verifications. Portions of the testing observed by the inspector included the following:

+ Use of a dead weight tester to verify that PT -2-3-56A tripped at the 1150 psig setpoint.

+ Use of a dead weight tester to verify that PT -2-3-56C tripped at the 1150 psig setpoint.

+ Verification that an RPS channel trip occurs and, following a 9 second time delay, that the recirculation pump MG set A/B field circuit breaker opened when a simulated level signal from LT-2-3-72A, B, C, D was set to -44.5 inches of water. Proper response of annunciators, relays and status lights was also verified.

+ Verification that the recirculation pump field circuit breakers opened when a test signal to PT-2-3-56A,B was raised to the 1150 psig trip setpoint.

+ Verification that the recirculation pump MG set field circuit breaker A/B opened when the RPT manual trip pushbutton was activated from CRP 9-4.

+ Verification of the 9 second time delay between LT-2-3-72D reaching the trip setpoint and RPT system trip.

All equipment functioned correctly during testing witnessed by the inspector. No inadequacies were identified.

Installation and testing of the RPT/Analog Trip System was completed prior to plant startup on December 23, 1980. Completion of these actions by the licensee and plant operation with the RPT system operable following the 1980 Refueling outage satisfies the requirements of the NRC's February 21, 1980 Confirmatory Order and conforms with the TS 3.2.I LCO requirements added to license DPR-28 by Amendment No. 58.

The inspector had no further comments on this item at the present. Followup review of licensee completion and closeout of the EDCR 79-02 design package will be conducted by the inspector as part of the routine inspection of the design change/modification program.

f. EDCR 80-46, SDV Water Level Measurement

Instrumentation installed under EDCR 80-46 constitutes additional VY action taken in response to IEB 80-17, BWR Failure to Scram.

The design of the scram discharge volume (SDV) system at VY employs two separate SDV headers, mounted above the North and South banks of hydraulic control units (HCU). The SDV headers for each Bank of HCUs consist of 6 inches diameter piping, which drains to a common 10 inch diameter scram instrument volume through separate 2 inch diameter drain lines. It has been recognized during NRC staff reviews of the various BWR SDV designs that the two inch diameter drain lines between the SDV headers and the instrument volume provides for poor hydraulic coupling between the volumes, and creates the potential for a situation in which the instrument volume could drain while the SDV headers still contain water. IEB 80-17 required that a method to monitor liquid level in the SDV headers be provided to assure that the pressure of water in the headers could be detected.

EDCR 80-46, SDV Water Level Measurement (approved October 20, 1980), added the provision for water level measurement at two separate locations in the SDV system. The design uses admittance probes made by Drexelbrook Engineering Company to provide continuous measurement of header water level. The probes are a sensor element that measure a capacitance change of water by direct immersion (proximity application). The probes produce an output current in the range from 4 to 20 mamp (corresponding to a range of input capacitance from 6 to 40,000 pf) based on the change in capacitance associated with a change in liquid level.

A single level probe is mounted in each of the North and South SDV headers. The probes are located in the 6 inch piping just upstream of the 6 inch to 2 inch pipe reducers. This location is in the low point of the 6 inch headers prior to reduction to the 2 inch piping. Output current (signal) from each probe goes to an electronic unit and setcon controller mounted on the 25-04 (25-22) panels in the Reactor Building and the CRP 9-16 panel, respectively. The electronic units provide a display of probe output (and hence header level) in the range from 0 to 100% full. Output displays from each probe are available in the Reactor Building and on CRP 9-5. The setcon controllers provide a channel alarm (control room annunciator) whenever a pre-determined setpoint is reached. The setpoint is adjustable and was set at 5%, which is a minimum practical setting that leaves sufficient volume in the SDV headers to assure the ability to scram.

The inspector determined that the following design criteria were applied to the system based on a review of the EDCR 80-46 design package:

+ industrial grade components, with fabrication and installation to conform with ASME B31.1 code requirements.

+ provision for vital power supply to the units, with a fail safe feature on loss of power.

+ consideration for dimensional clearances to include: clearance between 6 inch header pipe wall and the bottom of the vertically mounted probe; and, probe insertion length with allowances for mechanical installation tolerances.

+ consideration for environmental compatibility of system components and a verification, by calculation, that hydraulic forces generated during a scram will not adversely affect the immersed probe.

+ completion of a safety evaluation under 10 CFR 50.59 with the conclusion that no unreviewed safety question would be created by the installation and operation of the system.

Installation of the SDV level measurement system was followed by the inspector during the inspection period. The inspector also witnessed calibration and functional testing of the system in progress on December 5 and December 9, 1980. System calibration was accomplished in two phases. In the first phase, the electronic unit zero and span adjustments were set with the probes immersed in a bucket of water. System calibation for the second phase was completed with the probes mounted in the SDV headers.

The calibration method during the second phase consisted of adding water to the SDV headers by back-filling from the demineralized water system through the instrument volume. Portable UT equipment was used to measure the actual level of water in the headers as they were filled and to provide a reference for comparison with the admittance probe output. The probe electronics unit zero and span settings were adjusted during several fill/drain cycles such that 0 to 100% probe output corresponded to 0-6 inch water depth in the SDV header. Good correlation was achieved between the probe output and the actual water level in the headers as determined by the UT equipment. Except as noted below, the inspector had no further questions on the SDV water level measurement system design, installation, testing and operation.

Inspector review of the EDCR 80-46 design change resulted in several items that require further clarification. The items listed below were discussed with a licensee representative.

+ the design package did not address the specific temperature and pressure limits expected to occur in the SDV headers; this information is required for a comparison with the design temperature and pressure ratings for the probes.

+ the buildup of crud inside the headers and on the probes was not addressed, nor the effects of crud buildup on probe operation.

+ the change (inaccuracy) in probe output that may be caused by changes in water temperature; this effect is due to the change in the dielectric constant of water with change in temperature.

The licensee stated that these items would be reviewed and the results of his evaluation would be provided to the inspector. This item is considered open pending completion of the licensee's evaluation of the above concerns and subsequent review by the inspector (IFI 50-271/80-22-01).

9. RWCU Repairs - Material Conformances with NUREG 0313

Cracks and leakage in reactor water cleanup (RWCU) system piping inside the drywell was identified during the refueling outage and reported by the licensee to the NRC in LER 80-37 dated October 27, 1980. NRC review of the licensee's identification and repair of the subject piping is documented in other NRC Region I Inspection Reports (see Reports 50-271/80-15, 50-271/80-16, 50-271/80-17 and 50-271/80-20). NRC staff review of the RWCU system cracks and attendant circumstances led to the conclusion, subject to confirmation by metallurgical analysis of pipe specimens, that the cracks and pipe failures were caused by oxygen-induced intergrannular stress corrosion (IGSCC). In his October 27, 1980, letter to the NRC, the licensee committed to completing repairs of the subject pipes using material conforming to NUREG 0313, Revision 1. On December 2, 1980, the licensee's commitments and planned actions were discussed in a conference call with NRC Regional Staff. The commitments and planned actions were also formalized in a December 2, 1980, letter to the licensee from NRC Region I - Immediate Action Letter (IAL) 80-51. The NRC position specified by IAL 80-51 in regard to VY planned corrective actions was as follows: (i) repair of RWCU piping inside the drywell will be in accordance with the guidelines in NUREG 0313, Revision 1; (ii) materials employed will meet the intent of Section II of the NUREG: and, (iii) the material is considered to be conforming for the purposes of applying Section III of the NUREG.

The crux of the NRC position, and therefore conformance with NUREG 0313 guidelines, rests in the use of stainless steel piping with material properties that meet the specifications contained in NUREG 0313. For the purpose of control of IGSCC, the chemical constituent of prime importance is carbon content of the material. NUREG 0313 specifies that types 304L and 316L austenitic stainless steel are acceptable for use as corrosion resistant materials, or other material that have controlled low (0.02%) carbon content. During the conference call with the NRC staff on December 2, 1980, the use of piping with physical properties meeting the type 304 (316) specifications, but with low carbon content, was deemed acceptable and in conformance with the intent of NUREG 0313 requirements.

The inspector reviewed the information below to confirm that new piping used to replace the RWCU-18 line inside the drywell (and, up to and including the first outboard containment insolation valve) met the NUREG 0313 criteria.

+ Mercury Company Drawing No. WM-49849-102, Revision 3, Weld Map for CUW Change-out.

+ QC Weld Data Reports, Sheets 1 and 2, for VY SC1 piping - 4 inch RWCU line, replaced under Job No. 49849

+ Bill of Materials BM-49849-104 for JN 49849

+ Mill Certification No. VY U2926 dated May 30, 1979, for material SA-312 TP 316L with Heat No A932105; Items 2, 3

+ BAW Test Report A047193 dated August 22, 1980, for 2 inch schedule 160 material with Heat No. M5073; Item 9

+ BAW Certification D046964 dated May 15, 1980, for SA-312 TP 304L, Sch 80 material with Heat No. M4901; Item 8

+ GW, Taylor Bonney Division, Certificate No. T-305-74 for SA 403, Sch 80 material with Heat No. JPMX; Item 19

+ BAW Certificate No. 109452 dated May 17, 1975, for SA-312 TP 304L, Sch 80 material with Heat No. 8782 ; Item 20

+ BAW Certificate No. B086620 dated May 25, 1980, for SA 312 TP 316L, Sch 120 material with Heat No. A9C2703; Item 7

A review of the material test reports listed above showed that all subject piping was solution annealed to a specified temperature, followed by rapid (quench) cooling. Material carbon content was as follows:

Pipe Heat No.	Carbon Content
8782	0.021%
JPMX	0.023%
M4901	0.17%
M5073	0.014%
A932105	0.020%
A9C2703	0.019%

No inadequacies were identified. Based on the above, the licensee's actions were found in conformance with the IAL 80-51 requirements.

10. Inspector Followup of Events

The inspectors responded to events that occurred during the inspection to observe/review licensee response to the events and to verify continued safe operation in accordance with the Technical Specification and regulatory requirements. Some or all of the following items, as applicable, were considered during inspector 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 conformance to Technical Specification LCO require ments;

-- 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 voilation 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. Reactor Trip During Plant Startup

Plant startup was in progress on December 24, 1980, with a normal plant system line-up except for the RWCU system, which was isolated pending completion of final checks following maintenance and repair. An automatic reactor trip occurred at 7:22 A.M. due to low water level in the Reactor vessel at +10 inches. The inspector learned of the plant trip at about 7:30 A.M. upon arrival in the control room for routine plant status checks. Upon arrival in the control room, the inspector noted that: the reactor was shutdown, as indicated by SRM reading; an MSIV (group 1) isolation had occurred; standby gas treatment trains A and B were running; and, post-trip recovery procedures were being followed. Actions by control room personnel were orderly. Subsequent review of the event by the inspector with licensee personnel established the following sequence of events:

+ A normal startup was in progress, with reactor power at 8% FP (bottom of IRM Range 10), reactor pressure at about 350 psig (435^0F recirculation pump inlet) and the Mode Switch in STARTUP. Plant heatup rate was being controlled at about 30^0F/hr by control rod pulls. Control rods in the controlling group were being notch withdrawn to position 20, followed by continual withdrawal to position 48. In accordance with a recent revision to the startup procedure (OP 0101), reactor pressure control was maintained through control rod movement and auxiliary steam loads (AOG condenser, steam packing exhauster, etc.). The turbine bypass valves (BPV) were left closed, with a controller setpoint at 900 psig steam pressure. The procedure to not use the BPVs was different from previous practices. At 6:26 A.M., reactor feed pump (RFP) A was started in anticipation of eventual need for additional feedwater to the reactor.

+ Control rod withdrawal continued from 6:26 A.M. to 6:40 A.M. At this point, the control operator noted that a spike in feedwater flow had occurred, and that reactor temperature, pressure, level and power were higher than desired and increasing. Feedwater flow to the reactor vessel was reduced by shutting the startup feedwater regulating valve, V6-13, and opening V6-22B to reject additional water to the condenser. (The cause for the spike in feedwater flow was not determined for certain, but leakage past the main feed regulating valve seats is suspected). Actions to reduce feedwater flow were successful in stopping the increase in vessel level. However, reactor pressure was still increasing.

+ At 6:35 A.M., the operator started to notch in the selected control rod. Rod 22-11 went to full insertion within 1 minute in response to three sucessive single notch insertion commands - an abnormal rod response. A subsequent withdrawal command on rod 22-11 resulted in "flutter" of the rod around position 02 prior to stopping at position 02. Efforts to assess control rod system response, as well as stabilize RCS parameters, continued from 6:35 A.M. until 7:10 A.M. Apparently, no action had been taken to balance CRD system pressure with the now elevated reactor pressure using the CRD pressure control station.

+ At about 7:15 A.M., with RCS pressure stable but still higher than desired, the operator went to the MPR setpoint controller on the turbine control station to decrease the BPV pressure control setpoint from 900 psig. No BPV action was noticed as the setpoint decreased, even when the setpoint was at 800 psig with reactor pressure at 850 psig. The 50 psig mismatch was noted and considered "expected" since the control station had been worked on during the outage and the need for calibration with the plant on line had been recognized. (It was later learned that the lack of BPV response was due to binding of a mechanical linkage in the MPR pressure regulator, rather than excessive calibration mismatch). The MPR setpoint was decreased further.

+ At 7:20 A.M., the turbine BPVs began to respond (linkage became unstuck) and valve banks 1, 2 and 3 opened to compensate for the large mismatch between reactor pressure and the controlling setpoint. Operator attempts to raise the pressure setpoint were not fast enough to avoid a high steam flow condition. Also, at about this time, the A RFP was tripped since vessel level was still higher than desired at +50 inches.

+ The opening of three banks of BPVs with the mode switch in STARTUP caused a group 1 isolation (MSIVs shut) at 7:22 A.M. when steam flow reached 40% of rated flow. The combination of reduced feedwater flow and void collapse that accompanied MSIV closure caused vessel level to decrease. The reactor protection system automatically scrammed the reactor when level reached +10 inches. RFP C was started to restore vessel level. The vessel low-low setpoint was not reached. Licensee implementation of trip recovery procedures proceeded without incident.

Review of the trip sequence showed that all safety systems responded properly. Subsequent licensee investigation of the turbine control system identified the binding mechanical linkage in the pressure regulator section. The linkage was repaired on December 24, 1980. Subsequent control rod movements revealed no abnormal system responses. Following repair of the MPR mechanical linkages, no conditions were identified from the trip that would constitute a hold on a return to reactor operation. However, startup was delayed pending repair of a packing leak on RHR-V-81, identified during the Drywell close-out inspection at 7:05 A.M., December 24, 1980.

The inspector had no further comments on this item at the present. Further review of the licensee's Trip Report will be conducted on a subsequent routine inspection. No items of noncompliance were identified.

b. RWCU System Leakage

During a tour of the Reactor Building on December 29, 1980, while conducting leakage surveillance and taking shift readings, the #2 Auxiliary Operator noted wet piping insulation on the crossover line between the regenerative and non-regenerative heat exchangers. Upon removal of the insulation and inspection of the 4 inch diameter, schedule 80 Type 304 stainless steel piping, two through wall leaks were noted in a 5 foot section, horizontal run of the line. The pipe section with the leak is located below and adjacent to the regenerative heat exchanger. Power ascension was in progress at 25% FP when the leak was discovered. The RWCU system was isolated for repair and power operation was held at 25% FP pending return of the RWCU system to avoid perturbations on RCS chemistry. Reactor water conductivity was measured at about 1 umho/cm. The Technical Specification limit on conductivity is 5 umho/cm. Conductivity was monitored while the RWCU system was out of service for repair.

NRC review and inspection of RWCU system repairs was conducted by an NRC Region based inspector and inspection findings are documented in NRC Region I Inspection Report 50-271/81-01. In addition to the above inspection, the resident inspectors reviewed operational aspects of the RWCU leakage and monitored licensee corrective actions in progress. Findings are summarized below.

(1) The RWCU system was removed from service, isolated and drained at 1:35 P.M. on December 29, 1980. The alternate suction path

for the conductivity monitor from the recirculation loop was established to provide continuous trending of RCS conductivity. RCS samples were also taken periodically and analyzed for conductivity. Conductivity remained below 2 umho/cm for the duration of RWCU repairs.

(2) Stainless steel (Type 304) piping is used in the RWCU system from the suction point inside the drywell up to system check valve V12-62. Piping dowstream of V12-62, including tie-in with the feedwater and RCIC Lines outside the drywell is carbon steel piping. Portions of the system bounded by valves V12-18 and V12-62 are designated as Safety class 3 piping, in that piping failures within that boundary are isolable from the primary system boundary and thus, cannot cause a loss of coolant accident nor adversely affect the operation of a safety related system functioning the mitigate the consequences of an analyzed accident.

Based on the above, continued reactor operation with the RWCU system isolated was not contrary to license requirements.

However, the identified leakage in the RWCU system did constitute abnormal degradation of a system designed to contain radioactive material that requires repair and is reportable (30 day) under Technical Specification 6.7.B.2.d. LER 80-41/3L was submitted by the licensee to report the occurrence.

(3) A five foot section of the CUW-3 piping containing the defects was cut out. Upon examination (visual), a pitted, rough surface was noted on the outside surface of the piping near the two through wall defects. Visual examination of the inside surface of the piping showed a relatively smooth surface with an iron oxide film. The lack of corrosion on the inside of the pipe suggested that the defects originated from the outside diameter (O.D.). This finding will be confirmed following metallurgical analysis of the defects. Also apparent on the piping O.D. was a buildup of white crystalline deposits, which is probably wet-packed asbestos from the piping thermal insulation.

Section 9.1 of the Ebasco specification required that the insulation have a mixim leachable Cl^- concentration of 200 ppm and a minimum concentration of 50,000 ppm of sodium silicates. Onsite chemical analysis of the white deposits showed a Cl^- concentration of 200 ppm. Further chemical analysis of the piping insulation is scheduled by an offsite laboratory.

The CUW-3 piping is also coated with a corrosion resistant paint called "Thermal Lux Black 70". The paint is applied to the piping subsequent to installation and has, by specification, a minimum leachable silicate concentation. Further information on the paint was not available at the time of the inspection.

(4) Insulation on all CUW-3 piping was removed to allow visual examination of all piping between the heat exchanges. Portions of CUW-3 (about 50%) were also examined on a sampling basis by the liquid penetrant (LP) technique. The inspector examined the total length of CUW-3 piping and witnessed portions of the LP examinations in progress during the period from December 30, 1980 to January 2, 1981. Contractor personnel conducting the LP inspections were NDE QC Level II inspectors, as evidenced by Mercury Company NDE Certification Records submitted for inspector review. LP examinations witnessed by the inspector were reviewed for conformance with Mercury procedure Quality Control Procedure QCP-3104, Liquid Penetrant Examination Procedure, Revision 0, February 21, 1978.

LP and visual examination of the CUW-3 piping showed no evidence of external corrosion downstream of the 5 foot horizontal section immediately adjacent to the regenerative heat exchanger. (A minor exception to the otherwise clear findings on the downstream piping was a construction flaw (grind mark) that was identified and repaired on December 31, 1980).

LP examination of the 5 foot flawed section showed indications of cracking in locations other than the through wall defects. These indications were random in nature and showed no preferred direction. LP examination on the inside diameter of a 4 inch stub section of piping showed no crack indications, even in locations where O.D. cracking had been confirmed. This data provided further evidence that the corrosion was O.D. initiated. The nature of the observed indications was of a complex, low stress pattern suggestive of brittle failure in a ductile material. This type of cracking results in controlled leakage and not catastrophic failure. The postulated failure mechanism, based on a Cl^- source provided by the insulation, is stress corrosion cracking. The tube bundle flanges of the regenerative heat exchangers have had a history of leakage. Wetting of CUW-3 piping insulation from this leakage source would provide a mechanism for external stress corrosion of the line.

(5) NRC inspection findings of the RWCU repair are documented in Report 81-01, as noted above. Additionally, the resident

inspectors verified that piping used to replace the leaking CUW-3 pipe section was made of material conforming to NUREG 0313, Revision 1. See paragraph 8 above for details on the documentation review for piping with Heat No. 8782. Following repair of the CUW-3 piping, a hydrostatic test of the repair area was successfully completed on January 1, 1981.

(6) The RWCU system leaks (external to the drywell) and initial evaluations were discussed with site management. The inspector noted the following licensee positions: (i) the RWCU leaks identified on CUW-3 constitute a different problem and result from a different cause than the leaks from CUW-18, identified inside the drywell; (ii) the portions of the system under consideration are Safety Class 3 and are isolable from the RCS pressure boundary; (iii) routine, daily (shift basis) visual operator surveillance provides assurance of identifying leakage from piping under pressure in a timely manner. All high temperature system piping is covered by operator surveillance; and, (iv) following completion of metallurgical analyses on CUW-3 defect specimens, further review of the RWCU system susceptibility to leakage would be completed.

Based upon a review of appropriate sections of the FSAR, the Technical Specifications and the information presented by the licensee, the inspector identified no basis to disallow continued plant operation. Notwithstanding the above, this item is considered unresolved pending the following:

+ completion of the licensee's metallurgical analyses of CUW-3 defect specimens and chemical analyses of insulation specimens, and subsequent reporting to the NRC through a supplemental LER report;

+ completion of the licensee's evaluation of RWCU piping degradation, with considerations for cause mechanism, potential for generic concerns and the need for additional corrective actions; and,

+ completion of the NRC's evaluation of RWCU pipe degradation and review for generic concerns.

This item is unresolved (URI 50-271/80-22-02).

c. <u>MSIV Surveillance Testing</u>

On January 1, 1981, reactor power was at about 35% FP with power escalation in progress following RWCU system repairs (discussed above). Routine surveillance testing (per OP 4113) of the MSIVs at 11:10 P.M., January 1, 1981, revealed the following problems:

+ inboard MSIV V2-80B was timed to close in 5.5 seconds, which exceeded the maximum allowable closure time of 5.0 seconds;

+ outboard MSIV V2-86A was timed to close in 5.3 seconds, which exceeded the maximum allowable closure time of 5.0 seconds; and

+ closure testing of inboard MSIV V2-80C showed that closing time was proper, but that one of two position limit switches (F022C(2)) on the valve failed to de-energize its associated trip relay, K3F, when the valve was less than 90% open (see FSAR Figure 7.2-12). The K3F relay and associated trip circuitry was demonstrated operable by closure of the outboard isolation valve V2-86C. Similarly, the alternate position limit switch (F022C(1)) on MSIV V2-80C was demonstrated to be operable by de-energizing relay K3C.

In accordance with Technical Specification 3.7, MSIVs V2-86A and V2-80B were declared inoperable by shift personnel and the alternate valves in the A and B steam lines (MSIVs V2-80A and V2-86B) were closed. The failures associated with valves V2-86A and V2-80B constituted a 30 day reportable occurrence in accordance with Technical Specification Section 6.7.B.2. Shift personnel review of the failure associated with MSIV V2-80C concluded that no further action in regard to main steam line"C" was necessary in that RPS trip protection was still afforded by MSIV V2-86C and either of the two MSIVs on main steam line D. This conclusion was accurate and the actions taken by shift personnel were appropriate.

Subsequent site management review of the MSIV failures during the morning of January 2, 1981, resulted in an overly conservative interpretation of Technical Specification Table 3.1.1 requirements, with the conclusion that Table 3.1.1 Action 2 requirements had not been met. As such, the event constituted a 24 hour prompt reportable incident and LER 81-01/1P was submitted. Further, in that multiple failures had affected 3 of the 4 steam lines, site management elected to shutdown the reactor at Noon on January 2, 1981, pending restoration of all MSIVs to a fully operable status. This action was conservative.

Further site management review of the redundancy in the MSIV-RPS instrumentation concluded that the initial assessment of the event was overly conservative. Based on this subsequent review, the licensee informed the inspector that a 30 day followup report would be submitted instead of the 14 day followup report. Inspector review of the event in detail concluded that the licensee's actions were proper.

Maintenance requests issued to investigate the MSIV failures revealed the following:

+ MSIV V2-8B slow closure time was due to the closure time mechanism being out-of-adjustment. The timing mechanism was readjusted and V2-80B was subsequently tested satisfactorily.

+ MSIV V2-86A slow closure time was due to a broken spring in the hydraulic dash pot time adjustment mechanism. The spring was replaced and the mechanism was reassembled. V2-86A was subsequently tested satisfactorily.

+ The failure of V2-80C to de-energize relay K3F was found to be caused by a stuck actuator arm on limit switch F022C(2). The switch was repaired and the V2-80C was subsequently tested satisfactorily.

The inspector had no further comments on this event. No items of noncompliance were identified. Licensee submittal of the 30 day followup report for LER 81-01 will be followed on a subsequent inspection (IFI 50-271/80-22-03).

11. Anchor Bolt Replacement and Seismic Analyses

Licensee actions taken in regard to concerns raised by IEB 79-02 and IEB 79-14 were reviewed. The review was conducted in accordance with instructions contained in TI 2515/28 and TI 2515/29. Inspections and reviews conducted during this inspection period represent a continuation of the NRC Staff's ongoing review of IEB 79-02 and IEB 79-14 related issues. Previous reviews in this area are documented in NRC Region I Inspection Reports 50-271/79-09 and 50-271/79-13.

a. References

Documentation listed below and used during review of this area.

(1) IEB 79-02, Pipe Base Plate Designs Using Concrete Expansion Anchor Bolts, all issues through Revision 2 dated November 8, 1979

(2) VY internal memorandum entitled "Resonance System Hanger Description" dated August 7, 1979

(3) NRC Draft Meeting Minutes of IEB 79-02 Working Session dated June 4, 1979

(4) NRC internal memorandum on IEB 79-02 Factors of Safety dated February 15, 1980

(5) NRC internal memorandum on IEB 79-02 Factors of Safety dated March 3, 1980

(6) VY letter WVY 80-106 dated July 25, 1980

(7) VY letter WVY 80-31 dated February 28, 1980

(8) VY letter WVY 80-4 dated January 4, 1980

(9) VY letter WVY 79-127 dated October 29, 1979

(10) VY letter WVY 79-76 dated July 6, 1979

(11) NRC letter to VY (IAL 79-08) dated July 26, 1979

(12) VY letter WVY 79-85 dated July 31, 1979

(13) NRC letter to VY dated August 3, 1979 addressing proposed meeting agenda

(14) NRC internal memorandum dated August 20, 1979 providing a summary of a August 8, 1979 meeting with VYNPC

(15) VY letter 79-95 dated August 29, 1979

(16) OP 5200.16, Concrete Expansion Anchor Test Procedure

(17) QAP SP 49774 700, Concrete Expansion Anchor Removal and Replacement Anchor Installation Procedure

(18) Ebasco Services Inc., Purchase Contract No. NY-706116

(19) Docket 50-271 LERs No. 79-15, 79-23, 79-32, 79-33, 79-34 and 80-12

(20) Work Instruction BM-9002/WI-4, Revision 0, dated October 23, 1979

(21) Work Instruction BM-9002, Revision 0, dated October 23, 1979

(22) OQA Report 80-412/45 dated July 1, 1980

(23) OQA Report 80-445/237 dated August 11, 1980

(24) Mercury Company NCRs for Job No. 49774 (multiple)

(25) NRC Region I Construction Reports for Docket 50-271 for the period of 1968 through 1972

(26) IEB 79-14, Seismic Analysis For As-Build Safety-Related Piping Systems, all issues through Supplement 2 dated September 12, 1979.

(27) VY letter WVY 79-05 dated August 2, 1979

(28) VY Report WVY 79-144 dated December 13, 1979

(29) VY letter WVY 80-106 dated July 25, 1980

(30) NRC internal memorandum of telephone conversation dated July 1, 1980

b. Summary of Areas Inspected

The scope of the inspections conducted under each TI are summarized below:

IEB 79-02/TI 2515/28

(1) Review of Testing and Repair Procedures

(2) Verification that procedures incorporated certain general requirements that included: identification of expansion anchor bolt by type, diameter and length; definition of dimensions from edge of bolt hole to edge of plate; minimum embedment length specified; minimum thread engagement specified; dimension of base plate bolt holes; relocation distance requirements; considerations for base plate to surface gaps; examination of leveling nuts for grouted base plates; identification of criteria for repair program; and, specification of criteria for repairs.

(3) Verification that specific criteria were incorporated in the procedures providing instructions for use type expansion anchor bolts.

(4) Verification that the scope of testing was increased and/or a replacement program was implemented when testing showed a failure rate in excess of pre-established limits. As of August 1979, a complete replacement program was initiated at VY.

(5) verification of QA/QC documentation and engineering evaluations for replacement of anchor bolts.

(6) Verification of QA/QC documentation and engineering documentation for relocation of supports.

(7) Observations of work completed under the testing and replacement programs, and a review for conformance with applicable procedures. Hangers, Supports and Anchor Bolts on the following systems were observed and/or reviewed for general conformance to installation criteria:

+ HPCI: HD 74B, H 27, H 102B, H 24, HD 63, H 103B, H 62, H 108, H 81, H 103A, H 50, HD 35A, H 84, H 102, 20A, 20B, 35, HD 35A

+ RCIC: H 80, H 94, H 83, H 91, H 87, H 84, H 78, HD 83B, H 93, HD 63C, HD 63B, H 64, H 65, H 85, H 97 HD 7A, H 6, H 7, HD 84D, 20A, 20B, H 3, H 90, H 99

+ SLC: H 27, H 33, H 25, H 22, H 32, H 60, H 7A, H 7B, H 24, H 30, H 34, H 50, H 56, H 29, H 52, H 28, H 37, HD 37, H 35, H 36, H 38

+ MS: HD 70C, H 70, HD 101, HD 22B

+ CS: H 72, H 70, HD 75C, HD 60C, H 73, H 69, H 78, HD 74A

+ IA: HD 15A, HD 15B, HD 16A

+ RSW: H 216, H 22C, H 163, HD 177B, HD 178A, H 256, H 244

+ RCW: HD 127, H 139, H 161, H 142, H 93, H 156, H 102, H 101, H 153, H 157, H 145, H 154

+ ASCP: H 34, H 199, HD 27A, H 31

Expansion anchor bolts used in concrete block walls were replaced by through bolting and backing plates. No inadequacies were identified.

IEB 79-14/TI 2515/29

(8) Verification that the licensee established and implemented through his own organization, contractors and consultants, a program to inspect plant piping for conformance with pre-defined seismic criteria. Individuals responsible for development and implementation of the inspection program were interviewed and documentation used by personnel to conduct piping inspections was reviewed.

The documentation was reviewed to verify that inspection elements pertinent to inspection of seismic parameters were included. Seismic inspection elements included: pipe geometry; installed valves,with considerations for location, weight, dimensions and orientation of operators; type of support and location; restraint location and orientation; restraint clearances; location of anchor points; and, masses and center of gravity.

A contract organization (EES) provided field crews to walk-down plant piping systems to contruct detailed isometrics of the as-built system. Any additional data needed by NSD Engineering to complete the seismic calculations were also recorded. Systems included in the reviews were those originally defined as seismic class/safety related by FSAR Amendment 27. Once the isometrics and data were available, NSD and EES Engineering evaluated the field data, defined the seismic loads and redesigned supports, as needed. NSD Engineering provided final engineering approval for all modifications. Modifications that were identified as required by the analyses were completed by the Mercury Company, who also developed a QC program for the work.

(9) Observations of physical inspections in progress were completed during NRC Inspection 50-271/79-12.

(10) Verification that a program was established to identify, evaluate and resolve nonconformances in a timely manner.

(11) Verification that nonconformances were evaluated for impact on TS LCOs.

(12) Verification that nonconformances were reported in licensee submittals to the NRC, and that schedules for correction of significant nonconformances were also reported.

(13) Review of nonconformances to verify that identified deficiencies have been corrected.

c. Findings

(1) All work efforts in regard to IEB 79-02 have been completed as described in licensee correspondence to the NRC.

The inspector had no further questions in regard to licensee actions taken for IEB 79-02.

(2) Licensee work effort in regard to IEB 79-14 resulted in the generation of numerous nonconformance reports, some of which required that field modifications be completed. These modifications resulted from application of seismic criteria specified by FSAR Amendment 27. Further review and verification of the completion of these modifications will be conducted by the inspector on a subsequent inspection.

Additionally, the licensee initiated a program in 1978 to update the plant seismic design documentation due to a lack of sufficient information from construction turnover packages. The upgrade in seismic design documentation will conform to the seismic piping list of Regulatry Guide 1.29 and use the amplified response spectra (ARS) criteria described by Regulatory Guide 1.60. Use of the ARS methodology is considered an improvement over the original plant design analyses where the "Robinson Fix" multipliers were applied to the static design loads. Base plate flexibility will be incorporated in the new seismic analyses. Preliminary bounding calculations completed by the licensee have shown that base plate flexibility will have little, if any, effect on support load analysis.

All geometry verification work has been compelted. Seismic analyses using the ARS were scheduled to start in November, 1980 and be completed by June, 1981. The licensee was requested to inform the NRC, in writing, if this schedule is expected to change. Any modification shown to be required from the analyses will be completed by the end of 1981.

The inspector had no further questions on this item at the present. Licensee actions in this area will be followed on subsequent inspections.

Completion of licensee action in this area, and those items listed for inspector followup, are considered unresolved and are collectively designated as (UNR 50-271/80-22-04).

12. Observation of Surveillance Testing

Surveillance activities listed below were reviewed. Inspector review included a review of the completed test results and/or observation of testing in progress. The surveillances were reviewed to verify the activities were conducted in accordance with approved procedures and to verify that test results demonstrated system/component operation in accordance with Technical Specification LCO requirements.

a. Local Leak Rate Testing

A local leak rate test (Type B) of the torus NW access hatch was observed on December 1, 1980. Testing was conducted in accordance with OP 4030, Type B and C Primary Leak Rate Testing, inclusive of DI 80-23 dated November 4, 1980. Requirements for test precautions, prerequisites, equipment, data collection and analysis were reviewed and found satisfactory. RWP requirements were inspected and found to be met.

The access hatch seal areas were pressurized to 44 psig and the pressure was held for 30 minutes. The pressure drop over 30 minutes was recorded and found to be 0.1 psi. Test results from this test will be included in the summary report for all Type B testing.

No inadequacies were identified.

b. Integrated ECCS Testing

The Integrated ECCS test was completed on December 7, 1980, in accordance with OP 4100, ECCS Integrated Automatic Initiation Test, Revision 6, June 30, 1980. The test is designed to verify the proper integrated response of the emergency core cooling systems and the diesel generators to a simulated LOCA in conjuction with a loss of offsite power. The test was initiated by simulating a high drywell pressure in conjunction with a low-low reactor water level. The test results were reviewed by the inspector following the completion of testing. All systems responded properly, as noted by review by VYOPF 4100.01, VYOPF 4100.02, VYOPF 4100.03, and VYOPF 4100.04.

The inspector noted, however, that data sheet VYOPF 4100.01 was annotated to indicate that the A RBCCW pump failed to start. The RBCCW pumps supply both vital and non-vital loads. During a safeguards actuation, the RBCCW pumps provide essential cooling water to the RHR pump motor coolers. The A RBCCW pump is powered from 480V Switchgear Bus #9, which in turn is powered through Station Services Transformor T-9 and 4KV Bus #4 (DG A). The B RBCCW pump did start and was carried by 480V Switchgear Bus #8 during the test.

The inspector reviewed circuit wire diagram B-191301, Sheets 441, 441A and 442, which show the starting circuits for RBCCW P59-1A and 1B. The starting logic, with the pump control switch in AUTO, will cause a pump start after a one minute time delay only if a low RBCCW header pressure condition exists. Since the B pump did start during the Integrated ECCS Test and assuming the B pump was sequenced on ahead of the A pump, RBCCW header pressure above the low pressure setpoint would have prevented completion of the starting logic for the A pump. Thus, the A RBCCW pump responded in accordance with the starting logic.

The inspector had no further questions on this item for the present. However, this item is considered open pending further NRC review of the RBCCW start circuit design and the design bases for auto start of the RBCCW pumps on loss of normal power (IFI 50-271/80-22-05).

c. Primary Containmant Surveillance

During the inspection period, the inspectors monitored licensee actions in preparation for performance of VYOP 4115, Revision 10, March 26, 1980, Primary Containment Surveillance, Section G., Drywell/Suppression Chamber Vacuum Breaker Leakage Test.

The inspectors conducted a review of the procedure and discussed its performance with Operations Department personnel. The inspector noted that the procedure requires use of the Drywell/Torus H_2O Manometer instrument to establish the initial pressurization of 1-1.5 psi and noted to the shift supervisor that the manometer was currently out of service. The licensee noted the inspectors comment and Department Instruction 80-53 was issued prior to performance of the test to allow use of control room installed instrumentation DIP-1-158-6 and PRI-158-3 to monitor drywell pressure and drywell to torus D/P. The inspector had no further questions in this area.

No items of noncompliance were identified.

d. Primary Containment Integrated Leak Rate Test

(1) Witness of Test Activities

The inspector witnessed the preparation for and conduct of the primary containment integrated leak rate test during the period of December 18-21, 1980. Testing was conducted in accordance with OP 4029, inclusive of DI 80-29 dated December 21, 1980. The test procedure and test methodology had been previously reviewed (reference: NRC Region I Inspection Report 50-271/79-19) for conformance with the criteria of 10 CRF 50 Appendix J, ANSI N45.4, the VY Technical Specifications and established NRC positions relating to containment integrated leak rate testing.

The test was conducted by establishing an Appendix J valve lineup and then pressurizing the primary containment to greater than 44 psig (Pa). After stabilization was verified, the peak test pressure was maintained for 24 hours while searches for leakage were conducted and changes in contained air mass were measured.

The official test time ran from 1 P.M. on December 20, 1980 to 1 P.M. on December 21, 1980. A supplemental pump back verification test was completed. Based on a review of the preliminary test results, the CILRT appears to have been satisfactorily completed.

Inspector review of test activities included the following:

(a) verification, on a sampling basis, that valve positions during the test were as specified by OP 4029;

(b) verification that test prerequisites were met;

(c) verification that test instruments were calibrated as required by VY administrative procedures;

(d) verification that stabilization was achieved in accordance with established criteria;

(e) a review of the test exceptions list (#1 - #4) to verify that none of the changes constituted a change of intent;

(f) conduct of an inspec tour for leakage in the company of test personnel with the test pressure at 20 psia;

(g) verification that data was collected as required by OP 4029 and that manual data collection and computations were com-completed as required;

(h) partial verification of proper leak rate computation by the plant computer, based on manual calculations using the computer inputs;

(i) verification that instrument problems encountered during the test were appropriately resolved;

(j) verification that no maintenance was completed during the test; and,

(k) final review of preliminary test results to verify the Technical Specification limits were met.

No inadequacies were identified in regard to test methodology, test performance and the validity of test results. Preliminary test data and calculations indicated that the measured containment leakage rate was less than 0.201 wt %/day at the upper confidence limit. Except as noted below, the inspector had no further comments in this area.

(2) Appendix B Valve Lineup Change

While establishing the test prerequisites on December 18, 1981, it became necessary to change the required test valve lineup from that specified by Appendix B of OP 4029. Changes were made to Appendix B, Steps A.1, A.3 and A.10. The changes were required to: (i) incorporate the containment hydrogen monitoring system into the Type A test boundary in order to satisfy commitments made to NRC:NRR; and (ii) incorporate an alternate lineup of the condensate/feedwater system, as requested by the shift supervisor.

The inspector noted the changes, annotated in ink on the Appendix B data sheets. Although the inspectors review of the changes identified no technical concerns with the valve lineup exceptions, the inspector informed the Test Coordinator that the appropriate mechanism for effecting the changes, in accordance with plant administrative requirements, was to issue a Department Instruction (DI) per AP 0002. During ensuing discussions, which included upper site management, the licensee took the position that the "Exceptions Noted" statement in Appendix B allowed for valve lineup changes at the discretion of the Test Coordinator, and that any such exceptions would be subject to subsequent review by the PORC. The inspector noted the Exceptions List and the general intent for its use. However, the Exceptions List as written, with provisions for acknowledgement of changes by test personnel only, does not constitute a sufficient substitute for review and concurrence of changes to approved procedures by two individuals with a senior operator's license, as required by AP 0002 and Technical Specification 6.5.D. The administrative controls imposed by TS 6.5.D require the redundant, independent review of changes to approved procedures, prior to implementation, by senior licensed individuals to assure that such changes will not adversely impact safe plant operation.

Failure to obtain review and concurrence of changes to Appendix B of OP 4029 by two senior licensed individuals constitutes an item of noncompliance with AP 0002 and TS 6.5.D. (INC 50-271 80-22-06).

13. Annual Site Training

The inspector attended a site indoctrination/HP refresher training course on December 30, 1980, to satisfy site badging requirements. Topics covered during the training included: general site orientation; emergency response;

security; quality assurance; industrial safety; and, HP practices. Training topics were presented by video-tapes with supplemental discussions on certain topics given by the Training Coordinator. The inspector noted several minor discrepancies in the information given by video-tape. In each case, the followup discussion by the Training Coordinator corrected and/or augmented the tape information. The Training Coordinator stated that shortcomings of the video-tape presentations have been noted previously and that plans to upgrade the taped presentations were in progress.

No items of noncompliance were identified.

14. Unresolved Items

Unresolved items are items for which further information is required to to determine whether the items are acceptable or items of noncompliance. Unresolved items are discussed in paragraphs 10 and 11 of this report.

15. Management Meetings

Meetings were held periodically during the inspection with site management personnel to present inspection findings. A meeting with site management was also held prior to issuance of the report to summarize inspection scope and findings for the entire report period. The Resident Inspectors also attended the management meetings held by Region based personnel, including those held on: November 21, 1980 for Inspection Reports 80-19 and 80-20; December 3, 1980 for Inspection Report 80-18; December 5, 1980 for Inspection Report 80-21; and, January 5, 1981 for Inspection Report 81-01.

During the summary presentation of IR 80-22 findings on February 10, 1981, the licensee acknowledged the item of noncompliance discussed in paragraph 12 above, but took exception to the finding, with the position that changes made to the valve lineup were specifically allowed by the OP 4029 Exceptions List. The inspector acknowledged the licensee's position, but stated that the actions taken failed to meet the administrative control requirements of TS 6.5.D.