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REGION I

REPORT NO. 50-271/92-13

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LICENSE NO. DPR-28

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

FACILITY NAME: Vermont Nuclear Power Station

INSPECTION AT: Vernon, Vermont and King of Prussia, Pennsylvania

INSPECTION DATES: Vernon, Vermont, June 1 through June 5, 1992 and
King of Prussia, PA, June 8 through July 7, 1992

INSPECTORS: for S K Chaudhary 7/8/92
John Calvert, Reactor Engineer, Date
Electrical Section, EB, DRS

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S. K. Chaudhary, Sr. Reactor Engineer, Date
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APPROVED BY: J Knapp for PK Eapen 7/8/92
P. K. Eapen, Chief, Date
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Areas Inspected: A routine announced inspection of the licensee's management control program in the area of design change and modifications; technical adequacy of design changes; progress in the safety evaluation improvement program; and the overall effectiveness of the licensee's engineering organization to provide effective engineering and technical support to plant operations to assure safety.

Results: The licensee's engineering and technical support program is satisfactory. The licensee has implemented several new initiative to further strengthen these programs. No violations were identified.

1.0 SCOPE OF THE INSPECTION

The purpose of the inspection was to determine the effectiveness of the licensee's engineering and technical support to the Vermont Yankee Nuclear Power Station to assure safety. The scope included: the review of design, design changes and modifications in accordance with plant procedures, the requirements and commitments specified in the facilities Technical Specifications (TS), NRC rules and regulations, safety analysis report and quality assurance (QA) program; the licensee's organization structure and adequacy of staffing in the engineering area; communication/interface between corporate and site organizations; management support; workload and backlog; plant outage activities; assessment of weaknesses identified in the previous engineering and technical support portion of the systematic assessment of licensee performance (SALP) report; QA audits; capability of engineering staff to resolve technical issues; and technical training.

2.0 FINDINGS

2.1 Administrative Controls for Design Changes and Modifications

The inspectors reviewed administrative procedures and engineering procedures to determine whether the engineering activities are specified and controlled by approved procedures. The procedures reviewed included plant modifications, design change initiation, design input, design verification, safety evaluations, design document changes, and the modification/simple design change program.

The review indicated that the licensee's procedures provided adequate administrative guidelines and controls to ensure that design, design changes and modifications performed do not involve an unreviewed safety question. Appropriate requirements and guidelines are provided for the 10 CFR 50.59 screening review and safety evaluations, design input, design calculations and design verifications. The inspectors noted that the licensee was implementing a procedure update program to be consistent with 10 CFR 50.59 requirement for safety evaluation.

Additionally, the planned improvements in the "scoping memo" process should further improve the modification planning process and make it more effective.

2.2 Technical Training

The licensee continues to have a broad based administrative and technical training program for the site and corporate engineering staff. The training is grouped under three general areas, i.e. core training which is required of all engineering personnel at the time of initial employment, and position specific training which is related to an individual's assigned job, the third group is the elective training which is decided and requested by the staff and is approved by the functional supervisor.

The above training program is established and controlled by an approved procedure TSM-A.2, Rev. 6. This procedure was last updated and revised in September 1991. A comprehensive training matrix for 1992 that specifies training requirements and schedule has been developed and approved based on required, needed, and wanted training input from staff and supervisors. This training and qualification program enables managers and supervisors to assign tasks to the proper engineering staff.

Based on a review of the training program and discussions with the engineering staff and supervisors, the inspectors found them to be technically knowledgeable and familiar with the areas of their responsibility. The training program developed to address training needs of the engineering/technical staff was determined to be comprehensive and effective for engineering assignments. The inspector had no further question in this area.

2.3 Safety Evaluation for Design Change

The licensee's procedure and practices for performing safety evaluations for modifications and design changes was reviewed during an earlier inspection (IR 50-271/92-02). At the time of that inspection, the licensee was planning a comprehensive review and revision of the safety evaluation program.

The inspectors reviewed the draft new procedure for the safety evaluation. The procedure is fully developed and is being implemented on a trial basis. The licensee expects the final approval and full implementation of the procedure by early August 1992. The safety evaluation procedure and the accompanying training instructions with the procedure appear excellent. A few safety evaluations that had been performed using the new procedure were also of high quality.

2.4 Communication/Interfaces

An effective interface between the operations and engineering personnel exists at Vermont Yankee Nuclear power Station. This was evidenced by the daily morning meetings of operations, engineering, and other support organization staff. Effective interface amongst the site engineering, operations, and maintenance was enhanced by the participation of supervisory and management personnel from those organizations in these meetings. The plant managers meeting at the corporate office was effective in resolving interdepartment problems. The engineering scoping meeting for design change and modification planning was interdepartmental and multi-disciplinary in nature. Furthermore, the weekly Plant Operations Review Committee's meeting, and the bi-weekly plant manager's meeting contribute to resolving technical concerns and prioritizing work.

2.5 Engineering Backlog and Prioritization

The inspectors reviewed the licensee's backlog of design changes and modifications. The licensee prioritizes the modification work based on the safety impact/significance of the design change. The priority is established as high, medium, and low. This is done by an inter-disciplinary group of managers in the planning meetings that also establishes the schedule of the modification implementation, and assigns design change responsibility to the appropriate organization.

The inspectors noted that all the modifications scheduled for the 1992 spring outage were fully implemented. There was no backlog of unfinished design changes or other engineering work which would have impacted the implementation of modifications during the outage.

The absence of a backlog or rescheduling of high priority modifications beyond the 1992 outage was indicative of an emphasis on thorough engineering work, indepth preparation of modification packages, and a realistic implementation schedule with detailed outage planning. The inspectors had no further questions in this area.

2.6 Engineering Initiatives in Refueling Outage

Vessel Cladding Indications - During the recently completed outage, VY discovered indications of cracking in the reactor vessel cladding. The indications of cracking contained totally within the thickness of the cladding was an area that fell outside the bounds of ASME Section 11. As a result, VY with YNSD support, needed to define a plan for defining the problem and establishing acceptance criteria for NRC review and approval. The result of this effort was a sampling plan and analysis that was approved by the NRC without impacting VY outage plans.

New Feedwater Nozzle UT Method - During the most recent refueling outage a new UT technique was utilized to inspect the feedwater nozzles. This new technique provides a high level of confidence and sensitivity in flaw detection allowing improved detection of flaws in certain areas of the nozzles. Computer Aided design techniques were used to develop the transducer units for the new technique.

Containment Type "A" Test Methods - During the most recent refueling outage a new method was utilized to input type "A" test data to the diagnostic program. Automatic data acquisition and reduction is performed using the ERFIS and DVAX computers. Three computer programs and various ERFIS data points are used to determine the mass of dry air in the primary containment as a function of time, the leakage rate, and the statistical confidence for the leakage rate.

YNSD Engineers in VY Training - During the latest SALP period another YNSD engineer completed the Vermont Yankee Plant Certification program. In addition, Vermont Yankee continued to support the YNSD "Engineer in Training" program which provides an opportunity for YNSD engineers to spend up to a year at the plant site in support of various departments.

2.7 Reactor Water Cleanup System Line Break Analysis

YNSD was requested by Vermont Yankee to evaluate a Potential Reportable Condition (PRC) that was identified by General Electric Company at another BWR facility. The issue was related to the possibility of an unanalyzed high energy line break in the reactor building resulting from a reactor water cleanup line break and the single failure of a check valve.

YNSD evaluated the condition and determined that the specific incident described by General Electric was not applicable to Vermont Yankee because Vermont Yankee had two check valves in the steam tunnel; thus if one check valve failed to close the second one would preclude blowdown into the reactor building. YNSD reviewed the spectrum of breaks evaluated in the steam tunnel and was unable to determine if the GE specified scenario was analyzed in the steam tunnel. The 1980 EQ environment calculation by EDS Nuclear stated that an input assumption for the main steam line break was bounding in the steam tunnel. The sources for that assumption were 1973 and 1974 high energy line break reports prepared by Ebasco Services.

The Ebasco report evaluated a main steam line break, a feedwater line break and a combined main steam/feedwater break and concluded that the main steam line break was bounding. That evaluation was primarily concerned with pressure transients for structural evaluations; it was unclear to what degree the different environments were evaluated.

Because of this uncertainty YNSD determined that a detailed environmental transient analysis should be performed and a review of equipment qualification status performed.

This analysis has been completed and YNSD has determined that all required equipment is environmentally qualified for the new line break. The EQ Program will be updated to incorporate the results of this analysis.

2.8 Followup on Previously Identified Item

(Closed) Violation (50-271/90-80-05) This item pertained to inadequate safety evaluations performed for site initiated design changes. Additional concerns were later identified in the same area which were documented in inspection report No. 50-271/91-13. The corrective actions by the licensee for this area were underway. This item is closed because a comprehensive review of the effectiveness of the corrective actions in this area will be performed in the followup of items 50-271/91-13-01 and 04.

2.9 Design Modification Package Review

2.9.1 Analog Phase III (PDCR 90-008)

This safety-related change replaced equipment in the main steamline high flow channels of the group one trip section of the primary containment isolation system. The differential pressure switch channels were replaced with analog differential pressure transmitters and associated master/slave trip units. The reasons for the change were: to increase the accuracy and reliability of the channels; to simplify the calibration and functional tests; and to decrease the sensor calibration frequency from quarterly to once per cycle.

The master/slave trip units were previously removed from existing analog trip cabinets and put in stock. The units were removed from stock, new meter scales were affixed, and then were bench tested before being used for this change. The inspector reviewed the work control aspect of the meter scale changeout and bench calibration. The work was controlled, bench test procedures were used, the completed units were functionally tested, and data was recorded. The inspector found the control for the modification to be adequate.

In the review of the record package for this change, the inspector found that the total integrated radiation dose for the equipment was specified as 6 X 10^5 rads. The inspector pointed out to the licensee that the power supply used for the rack equipment was not qualified for this TID. The inspector also pointed out that the design had been completely reviewed and no reviewer commented that the power supply was not qualified to work at the 6 x 10^5 level. The licensee investigated and found that the wrong environment had been specified. The licensee initiated a change request that would change the TID to the correct value of 3.5 X 10^3 rads. This TID value will allow the use of the power supply. The inspector had no further questions concerning this issue.

In the review of the record package for this change, the inspector noted that a series of changes to calculations for the setpoints at the 140% and 40% of rated steam flow were made. The inspector reviewed the results of the setpoint calculations done prior to the change (VYC-687, revision 0), during review of the change (VYC-967, revision 0;VYI-18/91; VYI-8/92; VYI 18/92), and after the change (VYC-967, revision 1).

From the analysis of the 40% setpoint, it was concluded that the technical rationale of the setpoint calculations was clear and detailed, but the transmitter span, instead of the system pressure, was used in the static pressure zero shift calculation. This calculational error caused the setpoint uncertainty to be increased and could shift the upper limit of the setpoint to a value which could exceed the technical specification. The calculational error was investigated by the licensee, who corrected the error and contacted the vendor. The vendor sent additional information concerning systematic and random error uncertainty involved in the static pressure effect. The licensee recalculated the setpoint for the 40% steam flow case. The additional vendor information and a tighter calibration tolerance resulted in a net reduction of the setpoint error uncertainty range. The revised calculation is adequate to show that the upper limit of the setpoint due to instrument uncertainties will not exceed the technical specification.

The inspector also found that there was inadequate investigation of the larger implications of set points. In the 40% steam flow case, the set point actually had a lower limit set by operational considerations that were not recognized until the new set point was calculated and reviewed. Several iterations were required until an adequate solution was found. Each iteration focused on the set point of one instrument and not on the larger problem of coordination of the variables involved in mode switching and their design basis. Even the design basis of the particular instrument set point was avoided until the operational concern was raised. In addition, during the iteration process of raising the lower set point limit, the margin of the upper set point limit from the technical specification decreased. When the calculational error was uncovered, the licensee then contacted the vendor in order to determine the exact nature of the instrument specifications. The licensee has taken actions to determine the actual margins by reconstructing the design basis from the NSS vendor. The licensee has also taken actions to establish proper interpretation of vendor specifications before instrument accuracy calculations are processed. In a check of 22 similar calculations, the licensee determined that the same type of error did not exist. These licensee actions should improve the instrument accuracy/setpoint program and limit occurrences of this type to isolated cases.

The inspector walked down the installation of the completed electronic cabinets. The heat rise in the cabinet was minimal. There was no estimate of cabinet internal heat loads and no estimate or measurement of cabinet internal heat rise. A small fan is used to exhaust air from the cabinet, but the equipment is designed to withstand the resultant cabinet interior temperature in the event of fan failure. The cabinets are loaded with less than a card file of electronic modules plus a power supply mounted near the bottom of the cabinet. A thick, clear, hinged plexiglass type cover was mounted over the complete card file front to prevent inadvertent movement of control settings. The card file can be calibrated and tested from the front panel when a readout unit is inserted into the installed calibration unit. The inspector had no further questions in this area.

2.9.2 Feedwater Heater High-High Level Alarm (PDCR 90-009)

This non-safety-related change installed high-high water level instrumentation on two feedwater heaters. The high-high level alarm point reduces the potential for a turbine water induction accident and provides operators with a warning that heater water level has reached the point where corrective action must be taken.

The inspector reviewed the record package for this change. The float switches used were chosen from those which have satisfactory VY operating history in similar applications. Human factors were considered in placing the alarm windows at the top of the associated control room panel. The I&C calibration and test procedure was thorough and included convenient cross references of the water level set points to the volume in the tank. This cross referencing allows I&C detail requirements to be related to the physical plant process and provides consistency for cross-checking requirements versus test data. The inspector had no further questions in this area.

2.9.3 **Reactor Water Cleanup Control System Replacement (PDCR 91-006)**

This non-safety-related change is in the process of being re-bid by outside engineering contractor firms. The change involves replacement of electromechanical timer functions used in the demineralizer control panel with a programmable logic controller (PLC). A fault in the electromechanical system caused a precoat tank to exhaust a column of water twelve feet into the air. The plant engineering staff sees this change as a way to acquire knowledge of PLC's in the non-safety arena before tackling similar work in the safety arena.

The inspector reviewed the preliminary work done for the first bid package. The contractor selected went into chapter 11 protection before a contract could be negotiated. The procurement documents contained little in the way of technical requirements for system functions, environment, energy supply, hardware, software or acceptance tests. The basic considerations for solid state digital equipment were not stated, such as: inputs; processing; outputs; programming methods; software licenses; users guides; power line surges; electromagnetic interference conducted/radiated; shielding and grounding. The inspector concluded that for the first bid package, the licensee did not consider the technical requirements and basic considerations as thoroughly as for other non-safety-related plant changes.

2.9.4 **RPS MG Protection Panel Upgrade (PDCR 91-016)**

The reason for this safety-related change was to replace electrical protection assemblies that had a history of maintenance and setpoint drift problems. The new overvoltage, undervoltage, under frequency, and time delay electrical protection assemblies utilize solid-state integrated circuits. The breakers are normal electrical types. The new equipment monitors the same parameters and provides isolation to the RPS buses as the replaced equipment. Digital solid state time delay relays are added to provide defense against spurious trips of the respective bus breakers. The licensee has had reliable operation of similar equipment in the plant. The licensee conducted a search of the NPRDS for this type of equipment and no reported failures were in the data base. The equipment is installed in the non-harsh environment of the cable vault.

The inspector reviewed the record package and noted that the motor generators and the alternate source voltage regulator output voltages were reduced from 120 volts to 118 volts. To support this voltage reduction, an analysis of RPS loads verified that all equipment could operate between 111 and 125.5 volts. A thorough analysis of the setpoints and limits for the undervoltage, overvoltage, underfrequency, and time delays was made. The methodology covered the repeatability, frequency dependence, temperature effect, voltage effect, seismic effect, and calibration tolerance for each relay. The results verified that the settings in the normal and limit cases would not exceed the technical specifications (Tech. Spec. Table 4.10.1). The set points in the calibration/test procedure agree with the set point calculation values.

A new enclosure was made to house the electrical protection assemblies, breakers, dc power supply, terminal boards, test switch, test jacks and lights. The attention paid to seismic mounting and qualified parts was very good. An estimate of the enclosure heat loads or an estimate or measurement of internal temperature rise of the installed equipment was not made. Comparable equipment usually has a temperature rating of at least 122°F. The inspector subjectively determined that the temperature was below 90°F inside the enclosures during the walkdown. The ambient temperature inside the enclosure including the effect of internal heat loads is a major consideration for the reliable operation of solid state equipment. In this case, the margin between the maximum temperature that the solid state equipment can withstand and the actual installed enclosure internal temperature is adequate. The inspector had no further questions in this area.

2.9.5 RBCCW Heat Exchangers, Alternate SW Return Line (EDCR 92-401)

Service Water (SW) system valves V70-92A and V70-92B are the isolation valves for the Reactor Building Closed Cooling Water (RBCCW) heat exchanger's SW discharge. The valves are throttled during normal operations to maintain SW discharge temperature between 50-100° F with less than 10 psid across the heat exchanger (HX). The 12" valves were significantly throttled to meet this criteria and, because of the resulting seat wear, the valves could not isolate the heat exchangers. The licensee determined they had to replace the valves.

The licensee initiated Engineering Design Change Request 92-401 to add 4" service water (SW) outlets for both RBCCW heat exchangers, E8-1A and E8-1B. This design change was, in part, to support a temporary modification allowing the RBCCW system to operate during the replacement of the SW outlet isolation valves. The 4" lines can also serve as high capacity drains for the heat exchangers during routine maintenance. Temporary Modifications 92-27 and 92-28 use these outlets to establish an alternate SW discharge flow path.

The design change involved the removal of an existing 1" drain line and the installation of a 4" discharge line. The line consists of 4" carbon steel pipe, an elbow and flange, a stainless steel globe valve, and a threaded flange. The threaded flange provides an easy connection for operations to use when establishing the alternate SW discharge or drain paths. YNSD evaluated the impact of the design change on the design basis of the heat exchangers. The inspector reviewed the licensee's "Mechanical Calculations in Support of EDCR 92-401," contained in VYC-1045. The analysis covered 1) a geometry calculation to determine nozzle location, 2) an ASME VIII cylindrical shell area reinforcement calculation for the new four inch nozzle connection, and 3) a mechanical engineering calculations for dead weight, pressure, seismic and contingency loads on the heat exchanger. The inspector did not identify any deficiencies in the calculations and noted that the licensee had performed a thorough analysis.

The VY Maintenance Department managed the installation of the design change, which was performed in accordance with station procedures. The inspector reviewed the work packages including the installation and test procedures, component specifications, and post maintenance test results. The inspector did not identify any deficiencies in these areas.

The licensee stated that they developed EDCR 92-401 in a relatively short time. The design change was necessary to support the replacement of the SW system valves, V70-92A and V70-92B, during the 1992 refueling outage. The licensee also stated that replacement of these valves would be difficult during the 1994 refueling outage due to the scheduled Spent Fuel Pool Alternate Cooling modification. The inspector concluded that despite time constraints, the licensee had thoroughly evaluated and adequately implemented this design change.

2.9.6 Temporary Flowpath for SW Flow from RBCCW Heat Exchangers (TM 92-27 and 92-28)

The licensee established alternate RBCCW heat exchanger SW discharge paths to support the SW isolation valve replacement. Temporary Modifications (TM) 92-27 and 92-28 for heat exchangers E8-1A and E8-1B, respectively, established temporary flowpaths to the roof drain system. During the 1992 refueling outage, continued operation of the RBCCW system was necessary to provide cooling for the spent fuel pool, RHR pump seals, and CRD pumps.

The normal HX SW effluent flowpath is through the 12" line, the discharge isolation valve, and to the 18" main SW return header. The alternate flowpath is from the 4" SW outlet of the HX, through 200' of fire hose, and into a threaded Y connection on a 12" roof drain system pipe. The design operating pressure of the equipment necessary for the TM meets or exceeds the SW system design pressure.

The inspector reviewed the PORC approved Safety Evaluation for the TMs and the supporting YNSD engineering evaluations of 1) expected RBCCW temperatures and limits for shutdown conditions and 2) the RBCCW cooling capacity with service water flow isolated. The VY Safety Evaluation adequately addressed maintaining secondary containment, impact on FSAR accident analysis, and potential flooding. The inspector independently reviewed the licensee's assumptions, calculations and evaluations for TM 92-27 and 92-28. The inspector did not identify any deficiencies or new areas of concern.

2.9.7 Containment Spray Valve Replacement (PDCR 91-002)

Residual Heat Removal system valves, V10-26A and 31A, are the containment isolation valves for the Lower Containment Spray (CS) Header. Valves V10-26B and 31B are the containment isolation valves for the Upper CS header. The valves are 12", carbon steel, solid wedge, motor-operated, gate valves. Valves 26A, 31A, and 31B, have exhibited through seat or body leakage. After numerous attempts to eliminate leakage into the containment through these valves, the licensee decided to replace all four CS isolation valves. Due to RHR system operability requirements, valve configuration, and time constraints, the licensee could not replace V10-26B during the 1992 refuel outage.

The licensee initiated Plant Design Change Request (PDCR) 91-002 to replace the four gate valves. As part of this PDCR the licensee also installed a low point drain for the Lower CS header and modified pipe supports adjacent to the valves. The new valves are in kind replacements with one exception, they have a double disc rather than a solid wedge. For this reason the valve vendor equipped the new valve actuators with larger motors. VY requested that YNSD evaluate whether electrical work, such as changes in circuit breaker settings, cabling, or thermal overload sizing, was necessary. YNSD determined that no changes were required.

The CS isolation valves are cycled periodically for surveillance purposes and this results in water draining from between the valves into the headers. The Upper CS header nozzles are located on the underside of the pipe and allow water to drain from the header. The lower CS header nozzles are located on the inside equator of the pipe. Water above the nozzles will rain but the water below them will be trapped and corrode the header. As part of PDCR 91-002 the licensee installed a low point drain in the header. It is a non safety grade, seismically supported, 3/8" drain to a torus downcomer. YNSD calculated that a 3/8" drain hole in the header would have no effect on the Lower CS header capability.

The licensee removed several seismic supports to facilitate the replacement of the three isolation valves. As part of PDCR 91-002, YNSD reanalyzed these supports and determined that one support could be permanently removed and another could be simplified.

After the replacement of the three isolation valves and before returning the Containment Spray system to operation, the system was hydro tested to satisfy ASME Section XI and ISI requirements. The test results were acceptable and because the they included the 26B valve, the licensee concluded that it was acceptable to postpone the replacement of 26B until the next outage.

The inspector reviewed the completed work package and then discussed the project with the licensee. The inspector noted that the licensee diagnostically tested the motor operated valves to provide assurance of their capability and stroke time tested the valves to ensure compliance with the Technical Specifications. The inspector also noted that records of the licensee's review process showed the design change had undergone a substantial review by various departments of the licensee's organization. The inspector did not identify any weaknesses in this area.

3.0 CONCLUSION

Based on the above findings, the inspectors concluded that procedural controls and management attention applied over the design change and modification process was effective; the technical training of engineering personnel was adequate; communication and interfaces between various engineering departments and offsite organization was acceptable; and program and procedure to enhance the safety eva[illegible] process was nearing completion. The new safety evaluation process as planned a[illegible]vident by the draft procedure was determined to be very good.

The design change/modification packages reviewed by the inspectors were comprehensive and engin[illegible]ing/technical quality was acceptable. There was no backlog of priority one design changes from the last refueling outage. Additionally, the engineering management had effectively implemented several new test methods to improve the sensitivity and reliability of test data.

In summary, the engineering and design change program controls and outputs, and management attention in this area was acceptable.

4.0 MANAGEMENT MEETING

At the conclusion of the inspection, the inspectors met with licensee representatives (listed in Attachment 1) where the inspectors summarized the scope and findings of this inspection.

The licensee did not indicate that any proprietary material was included within the scope of this inspection.

ATTACHMENT 1

PERSONS CONTACTED

Vermont Yankee Nuclear Power Corporation

*D. Reid, Plant Manager
*S. Jefferson, Assistant to Plant Manager
*R. Pagodin, Technical Services Superintendent
*R. Grippardi, Quality Assurance Supervisor
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*J. DeVincentis, Technical Program Supervisor
*J. Hoffman, Engineering Manager, VY Projects
*J. Pelletier, Vice President, Engineering
*B. Buteau, Engineering Director

U.S. Nuclear Regulatory Commission

H. Eichenholz, Senior Resident Inspector
*P. Harris, Resident Inspector

Asterisk (*) denotes those present at the exit meeting.