U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/Report No.: 50-293/88-12

Licensee: Boston Edison Company
800 Boylston Street
Boston, Massachusetts 02199

Facility: Pilgrim Nuclear Power Station

Location: Plymouth, Massachusetts

Dates: March 6, 1988 - April 17, 1988

Inspectors: C. Warren, Senior Resident Inspector
J. Lyash, Resident Inspector
T. Kim, Resident Inspector
J. Golla, Reactor Engineer

Approved by: [signature] 5-31-88
A. Randy Blough, Chief — Date
Reactor Projects Section No. 3B
Division of Reactor Projects

Inspection Summary:

Areas Inspected: Routine resident inspection of plant operations, radiation protection, physical security, plant events, maintenance, surveillance, outage activities, and reports to the NRC. Principal licensee management representatives contacted are listed in Attachment I. Copies of handouts used by the licensee during their March 10, 1988 presentation on the Direct Torus Vent Modification are included as Attachment II.

Results:

Violation: Inadequate design control and review were evidenced in the incorrect installation of the reactor water level gauges. Also, weaknesses in adequate test procedures and technical reviews were identified in the preoperational tests performed on these instruments. (VIO 88-12-02 Section 3.c)

Unresolved Item: An error in the licensee's procedure for calculation of battery capacity was not identified during a performance test or post-test reviews. Other battery testing and maintenance weaknesses were also identified. (UNR 88-12-01, Section 3.b)

Strengths:

1. The licensee's approach to problem investigation and root cause analysis was prompt and positive. Event critiques led by the Operations Section Manager and root cause analyses performed by the onsite Systems Engineering Group appeared to be thorough and aggressive. (Sections 2 and 3.c)

2. The levels of detail, technical accuracy, and the overall quality of LERs have improved during the last six months. (Section 5)

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DETAILS

1.0 Summary of Facility and NRC Activities

The plant was shutdown on April 12, 1986 for unscheduled maintenance. On July 25, 1986, Boston Edison announced that the outage would be extended to include refueling and completion of certain modifications. The reactor core was defueled on February 13, 1987. The licensee completed fuel reload on October 14, 1987. Reinstallation of the reactor vessel internal components and the vessel head was followed by completion of the reactor vessel hydrostatic test. The primary containment integrated leak rate test was also completed during the week of December 21, 1987.

During this report period, the licensee continued with the post modification/maintenance testing of plant equipment. Effective on March 30, 1988, Mr. Roy A. Anderson, former Planning and Outage Manager at Pilgrim, relieved Mr. Robert J. Barrett as the Plant Manager. The licensee has not yet named a permanent replacement for Mr. Anderson. It was announced on March 29, 1988 that Mr. F. N. Famulari, former Deputy Quality Assurance Department Manager, has replaced Mr. D. L. Gillespie as the Quality Assurance Department Manager. Also, effective on April 1, 1988, Mr. C. J. Gannon left his position of the Radiation Protection Manager to become the Planning and Outage Services Section Manager. Mr. W. Mullins was named the Acting Radiation Protection Manager/Chief Radiological Engineer until a permanent Radiation Protection Manager is selected.

NRC inspection activities during the report period included: 1) evaluation of the licensee's revised Emergency Operating Procedures during the week of March 14, 1988, 2) review of the licensee's radioactive waste processing systems and effluent monitoring during the week of April 4, 1988, 3) evaluation of the licensee's security program effectiveness during the week of April 11, 1988, and 4) review of previous inspection findings during the week of April 11, 1988. On March 9, 1988, Mr. William T. Russell, Regional Administrator, Region I, toured the station with the resident inspectors. Also on March 10, 1988, Dr. Thomas E. Murley, Director, Office of Nuclear Reactor Regulation (NRR), Mr. William T. Russell, and other management representatives from both NRR and Region I toured the site, inspected the plant areas where the direct torus vent system has been installed, and interviewed licensee engineering department personnel regarding the system.

2.0 Followup on Previous Inspection Findings

(Update) Unresolved Item (UNR 87-53-05), Part 3, Review the results of licensee inspection of the Emergency Diesel Generator (EDG) lube oil filters and strainers. During the November 12, 1987 loss of offsite power event the prelube pump for the "B" EDG failed to restart on demand. It was identified that metal chips had become lodged between pump internal components, causing the pump to bind. The licensee agreed to perform inspections of other lube oil system components to determine if additional foreign material was present. The "B" EDG lube oil system was subsequently drained. The inspector witnessed licensee inspection of the lube oil sump, filters, and strainer. No foreign material which could have caused the prelube pump failure was identified. Similar inspections were later performed on the "A" EDG during a routine equipment outage. No significant foreign material was found. These inspections indicate that externally generated material was not the cause of the pump failure.

On December 13, 1987 the "B" EDG prelube pump again failed to start when energized. Disassembly revealed a failure identical to that observed in November 1987. The licensee sent parts from one of the failed pumps to a materials laboratory for analysis. Results from this analysis indicated that a loss of internal clearance caused severe idler gear chafing against the pump head to the point of spot-melting. This allowed chips to tear from the pump head, weld to the idler gear, and cause the failures. The licensee's system engineering group believes that the loss of internal clearance is caused by an inability of the pump to absorb thermal growth. The pump shaft is direct coupled to the motor. The drive gear is slip fit to this pump shaft. Each pump was found to have rust between the shaft and the drive gear, eliminating any drive gear movement during thermal growth. The licensee has contacted both the pump and diesel vendors regarding the results of the evaluation. In addition, the licensee engineering department is reviewing the current application to determine if pump replacement with an alternate design is warranted. The prelube pumps are not considered safety-related. The licensee's root cause evaluation appears to have been thorough. The pumps are routinely shutdown and restarted during biweekly EDG surveillances. The licensee is pursuing available replacement options. The inspector had no further questions. This portion of UNR 87-53-05 is considered closed. Remaining portions of this item will be reviewed during future inspections.

(Closed) Inspector Follow Item (86-29-03), review licensee analysis of standby gas treatment system (SGTS) single failures. This item was last updated in inspection report 50-293/88-07. The inspector expressed concern that the 2000 Cubic Feet per Minute (CFM) setpoint for the SGTS discharge flow monitor would not ensure a negative secondary containment pressure under all circumstances. If the operating train were degraded and flow remained just above the 2000 CFM trip point, the standby train would not automatically start and the secondary containment function could be lost. The licensee provided the inspector with Field Revision Notice (FRN) 86-70-270 dated September 27, 1987. This FRN raised the flow setpoint to 3350 CFM. Based on review of the safety evaluation included with the FRN, and recent SGTS performance testing results, it appears that this change adequately addresses the inspector's concern.

The inspector also questioned the need to perform a post-work flow test to verify proper sizing of the newly installed crosstie cooling orifice. Licensee calculations, construction documentation and a description of controls applied to final inspection and system closeout were provided by the licensee. The licensee stated that the above items constitute sufficient basis to conclude that the orifice is correctly sized and installed. Periodic performance tests of the system, required by technical specifications, would also indicate any substantial blockage or design error. The inspector had no further questions. Based on the above, this item is considered closed.

(Closed) Violation (87-45-03). In response to discovery of non-job related reading materials and a card playing machine in the control room the licensee took steps to identify the source of the materials and whether they had been used by on-shift personnel.

Personal interviews were conducted by the Senior Vice President-Nuclear with members of the Operations Department. The result of these interviews established that the materials were brought to the control room by members of the operations staff. The licensee's investigation did not identify cases where the material had been used in the control room. In addition to the interviews, the licensee took additional actions to preclude recurrence. These additional steps included meetings between senior management and the operations staff, assignment of management personnel to observe backshift and weekend control room conduct, and prohibition of non-work related reading material and entertainment devices from any process building.

Based on the results of the licensee's investigation and control room observations and interviews conducted by NRC personnel this item is closed.

(Closed) Unresolved Item 87-57-02, incorrectly installed reactor vessel level gauges. The details of this item are discussed in Section 3.c of this report.

3.0 Routine Periodic Inspections

The inspectors routinely toured the facility during normal and backshift hours to assess general plant and equipment conditions, housekeeping, and adherence to fire protection, security and radiological control measures. Inspections were conducted between 10:00 p.m. and 6:00 a.m. on April 7 and April 16, 1988 for a total of four hours and during the weekends of March 26, April 9 and April 10, 1988 for a total of nine hours. Ongoing work activities were monitored to verify that they were being conducted in accordance with approved administrative and technical procedures, and that proper communications with the control room staff had been established. The inspector observed valve, instrument and electrical equipment lineups in the field to ensure that they were consistent with system operability requirements and operating procedures.

During tours of the control room the inspectors verified proper staffing, access control and operator attentiveness. Adherence to procedures and limiting conditions for operations was evaluated. The inspectors examined equipment lineup and operability, instrument traces and status of control room annunciators. Various control room logs and other available licensee documentation were reviewed.

The inspector observed and reviewed outage, maintenance and problem investigation activities to verify compliance with regulations, procedures, codes and standards. Involvement of QA/QC, safety tag use, personnel qualifications, fire protection precautions, retest requirements, and reportability were assessed.

The inspector observed tests to verify performance in accordance with approved procedures and LCO's, collection of valid test results, removal and restoration of equipment, and deficiency review and resolution.

Radiological controls were observed on a routine basis during the reporting period. Standard industry radiological work practices, conformance to radiological control procedures and 10 CFR Part 20 requirements were observed. Independent surveys of radiological boundaries and random surveys of nonradiological points throughout the facility were taken by the inspector.

Checks were made to determine whether security conditions met regulatory requirements, the physical security plan, and approved procedures. Those checks included security staffing, protected and vital area barriers, personnel identification, access control, badging, and compensatory measures when required.

a. General Plant Tour Observations

On March 10, 1988, Dr. Thomas Murley, Director of the NRC Office of Nuclear Reactor Regulation (NRR), and Mr. William Russell, Administrator of NRC Region I, toured the plant with the resident inspectors. In addition to a general plant tour, installed portions of the licensee's direct torus vent (DTV) modification were examined. Subsequently, Dr. Murley, Mr. Russell and members of the NRC technical staff interviewed licensee staff and received a presentation describing the development and design basis of the DTV. Copies of handouts used by the licensee during the presentation are included as Attachment II.

b. Region I Temporary Instruction 87-07, Storage Battery Adequacy Audit

Region I Temporary Instruction (RTI) 87-07 was performed to determine if the licensee has established a program to ensure storage battery operability, in accordance with the current licensing basis. The safety-related DC power system at Pilgrim includes three class 1E, seismically qualified, lead-calcium type storage batteries. Two divisional, sixty cell, 125 VDC batteries supply safety-related control power and some motor operated valve (MOV) loads. A single 120 cell 250 VDC lead-calcium battery supplies motive power to the high pressure coolant injection system MOVs. Each of these three batteries is equipped with a dedicated charger. A single backup charger is shared between the two 125 VDC batteries, and a second backup charger is provided for the 250 VDC battery. In addition to these three safety-related batteries, Technical Specifications require an operable 125 VDC battery to serve switchyard and transformer protective relaying circuits. Two sixty cell lead-calcium batteries located in the relay house are installed to fulfill this requirement. Technical Specifications also require the operability of the 24 VDC battery and charger associated with the diesel fire pump. Other station batteries not addressed by Technical Specifications include two neutron monitoring system 24 VDC batteries; one 125 VDC security battery, diesel generator air compressor 12 VDC battery, and emergency lighting batteries.

Several previous NRC inspections have focused on design, maintenance and testing of storage batteries at Pilgrim. NRC Performance Assessment Team (PAT) 50-293/85-30 performed a detailed review of the modification package for replacement of the 250 VDC battery. The PAT reviewed design specifications, manufacturer's duty test results, licensee periodic battery performance testing and battery operability criteria. Specialist inspections 50-293/87-09 and 87-21 reviewed the technical adequacy of battery performance test procedures, test results, battery storage area housekeeping, and physical condition of the cells, intertie bars and storage racks. Special NRC Electrical Team Inspection 50-293/88-08 also performed inspections of battery and storage rack physical condition. Inspections 87-09, 87-21 and 88-08 all identified indicators of poor battery maintenance practices. Inspection 88-08 contains a notice of violation addressing this area.

During the current period the inspector toured each of the battery areas and examined general housekeeping, physical location and arrangement of the area, the existing condition of the batteries and racks, and verified the operability of storage area ventilation systems. Cleanliness and housekeeping conditions had improved somewhat from those noted in NRC inspection 50-293/88-08. The three safety-related storage batteries along with the neutron monitoring batteries are located in dedicated, locked rooms in the turbine building. A ventilation system is provided to maintain acceptable room temperatures. The ventilation exhaust is withdrawn from the area high point to prevent gas buildup. Associated fans, dampers and duct work appeared to be in good condition.

The licensee presently monitors pilot cell condition weekly, specific gravity and voltage of all cells quarterly, and performs a discharge test once each operating cycle. This testing is applied to all station batteries. The procedures appeared to be technically adequate and consistent with the vendor manual and industry standards. Appropriate battery and storage rack physical inspection and maintenance instructions were included to ensure continuing seismic qualification. Precautions regarding proper ventilation and protection from ignition hazards were contained. The licensee maintains a battery charger maintenance and calibration procedure.

The inspector reviewed the licensee's DC load profile and its basis. Current DC system configuration was reviewed to determine consistency with the assumed loads. Both safety-related 125 VDC batteries and the 250 VDC battery were replaced in 1980 and 1981 respectively. Results of the most recent discharge tests were evaluated and indicate that sufficient capacity, under worst case circumstances, still exists. Typical test results indicate capacities in excess of 95 percent of original values. An overall minimum capacity of 80 percent has been established as the battery electrical end of life. The licensee plans to conduct a duty cycle test during the next refueling outage.

The inspector noted that the formula used to calculate battery capacity in procedure 8.9.8, Battery Rated Load Discharge Test, is incorrect. Application of the temperature correction factor as specified yields invalid results. In completed discharge tests reviewed, it appears that personnel completing the calculation did not apply the correction factor because of this formula error. In addition the discrepancy was not identified during the licensee's post-test results review. The effect on the results however, is minimal, less than two percent. The licensee committed to review the procedures and to make appropriate corrections. Procedure 8.9.8 also includes steps for recharging of the battery after completion of testing. However, only a single set of specific gravity and cell voltage readings are taken to verify acceptable battery recharge. No followup readings are included to verify that the battery parameters are stabilized. The licensee stated that in practice, operations personnel do take followup readings. The licensee maintenance manager stated that the need to formalize this practice by incorporation into procedure 8.9.8 would be evaluated. The inspector requested the results of the most recent battery charger calibration and maintenance activity. The licensee was not able to provide documentation of this work prior to the close of the inspection period. The licensee committed to identify the last time the procedure had been performed and to supply the results and next scheduled performance date to the inspector.

During the inspection period the operations department performed surveillance procedure 8.C.16, Quarterly Battery Cell Surveillance. Specific gravity readings for a large number of cells on several of the batteries were found out of specification. The licensee later identified that the wrong type of hydrometer had been used to take the readings. Use of the correct hydrometer resulted in acceptable results. The inspector noted that the hydrometer usually used in performance of the test is maintained by the operations department and is not a controlled or calibrated instrument. The Operations Section Manager stated that a controlled instrument would be used in future testing. The inspector also noted that water used for addition to batteries was stored in bottles in the battery rooms. This does not represent positive control of water quality. The Operations Section Manager stated that the bottles would be removed and water for makeup to the batteries would be obtained directly from the chemistry department.

Licensee actions to correct deficiencies in procedure 8.9.8, ensure use of a controlled instrument for measuring specific gravities, provide better control of water quality and to provide the results of battery charger surveillances will be evaluated in a future inspection under unresolved item 88-12-01.

c. Plant Maintenance and Outage Activities

Followup of HFA Relay Failures

On January 17, 1988, a spurious reactor scram signal was generated during a routine instrument calibration. Following the actuation the licensee identified that a secondary containment isolation had not resulted as designed. Investigation revealed that a contact on a General Electric (GE) HFA relay had not fully closed when the relay was deenergized. Failure of the contacts to close prevented the isolation signal from going to completion. This incident was described in paragraph 4.d of resident inspection report 50-293/87-57.

The failed relay was removed and shipped to GE for testing. Both GE and licensee analyses concluded that the relay had been improperly adjusted during installation. Individual contact fingers must be adjusted to provide adequate contact wipe on closure. The failed relay contact was found to have very little wipe. When the relay was deenergized and the contact closed it continued to display high resistance. The relay was adjusted and installed just prior to refueling by a licensee electrical technician. This technician installed only one additional relay at that time. The licensee removed the second relay and found indications of similar misadjustments. The procedures used by the technician appeared adequate. The training provided prior to the relay replacement however, may have been weak.

On March 16, 1988, the Watch Engineer noted that automatic scram relay 5A-K14C was chattering loudly. As a precaution a manual half scram was inserted and the relay deenergized. Licensee investigation identified that relay 5A-K14C was chattering due to insufficient voltage supply to the coil. GE HFA relay 5A-K4C contacts in the power supply circuit for the 5A-K14C coil exhibited high resistance, causing the observed voltage loss. Relay 5A-K4C was removed, examined and found to have inadequate contact wipe resulting from misadjustment. This misadjustment was similar to the condition found on the secondary containment isolation relays described above. During the current outage the licensee replaced about 180 HFA relays. A special relay setup and replacement team was formed and extensive training was conducted. In addition 100 percent quality control coverage of the activities was maintained. Improperly adjusted relay 5A-K4C was installed by this team. The licensee's systems engineering group is developing a matrix of personnel versus relay replacements in which they were involved. A temporary procedure will be written to sample the 180 relays replaced this outage using a sample plan based on the matrix. The licensee is also reevaluating the training provided and the procedures used. The inspector will continue to monitor licensee followup in this area.

Incorrectly installed Reactor Level Gauges

During a followup investigation to an inadvertent reactor scram signal on January 17, 1988, the licensee identified two reactor vessel level instruments (LI 263-59 A&B) with incorrectly connected sensing lines. The instruments were recently installed under Plant Design Change (PDC) 85-07 and had not been turned over to the operations department. These new Barton gauges would only be used for local indication if reactor shutdown from outside the control room was needed. The incorrect installation was due to an error in the configuration drawings which were issued as a part of Field Revision Notice (FRN) No. 62 to PDC 85-07. The initial PDC 85-07 package was reviewed by the plant Operations Review Committee (ORC) for its impact on plant safety and also for its adequacy. FRN 62 however was not considered as a major FRN and thus bypassed the ORC review. The licensee initiated a Potential Condition Adverse to Quality Report to track this concern. Their engineering department is reviewing the requirements and guidelines for determining major versus minor FRN.

Based on review of licensee records and interviews with licensee personnel, the inspector determined that the pre-operational testing of the instruments was inadequate. The pre-operational testing procedure TP 87-86 did not prove that the instruments tracked actual water level as required by the PDC 85-07. Instead, TP 87-66 appeared to be a simple instrument calibration. The inspector also reviewed the daily operator surveillance records, Station Procedure 2 1.15, and noted that the instruments LI 263-59 A&B have been checked with readings recorded as pegged high. The operators interviewed indicated that they had not raised any questions about the abnormal gauge readings since both gauges were tagged out of service and had not been turned over to Operations. The inspector noted that these instruments (LI 263-59 A&B) are not included anywhere in the Technical Specifications (TS). The licensee is reviewing the regulatory requirements and licensee commitments to determine if the instruments should be in the TS.

The licensee's investigation concluded that the cause of the scram was the particular method used to calibrate the instruments. The calibration was performed with the instruments isolated from the process line and drained of all the water. The test equipment was attached to the instruments and air pressure was used to simulate the differential pressure from the process. When the instruments were returned to service, the air pockets released into the lines caused pressure fluctuation at several instruments served by the same lines, resulting in the reactor scram. The licensee indicated to the inspector that the proposed corrective actions include revising the Procedure 8.M.2-2.1.2 to require "wet" calibration and to evaluate the adequacy of other instrument calibration procedures. The inspector will review the licensee actions in this area in a future inspection.

The licensee's investigation and root cause analysis led by the on-site Systems Engineering Group were aggressive and thorough. The licensee is currently reviewing the adequacy of other safety-related protective instruments installed during this outage. Thus far, the problems associated with the instruments (LI 263-59 A&B) appeared to be an isolated case. However, the design control deficiency as evidenced in the FRN 85-07-62 is in violation of 10 CFR 50, Appendix B, Criterion III, and the Boston Edison Company Quality Assurance Manual (BEQAM). BEQAM Section 3, Design Control, requires that measures be established for the control of design activities to assure appropriate quality standards and design reviews. Further, BEQAM Section 8.3.2.8 requires that methods for verifying design changes, such as design reviews and qualification testing are properly chosen and followed; the most adverse design conditions are specified for test programs used to verify the adequacy of designs. Contrary to the above on January 19, 1988, it was determined that parts of the Plant Design Change (PDC) 85-07 for installation of new reactor water level gauges had not been properly reviewed and released in that the configuration drawings were incorrect, which resulted in incorrect installation of the gauges. The FRN 85-07-62 was released on December 12, 1986 and the implementation of the FRN 85-07-62 was completed on April 22, 1987. It was also determined that the design verification testing for the installed reactor water level gauges, Temporary Procedure 87-66, Pre-operational Test of the New Barton Indicating Units LI 263-59A and LI 263-59B, completed on June 10, 1987, did not meet the requirements of the BEQAM, Section 3.3.2.8 in that the testing failed to verify the design adequacy (VIO 88-12-02). Failure to establish adequate test procedures and to perform adequate technical review during the blackout diesel generator testing and the plant process computer point tie-in activities were the subject of a previous violation as documented in the inspection report 50-293/88-07.

d. December 1987 Containment Integrated Leak Rate Test (CILRT) Results Evaluation

The inspector reviewed the licensee's December 1987 CILRT results documented in accordance with the requirements of 10 CFR 50 Appendix J paragraph V.B.3. These results were summarized in a technical document entitled "Reactor Containment Building Integrated Leakage Rate Test" and attached to the licensee's letter dated March 15, 1988 to the NRC. The report contains a test summary and general test description, presentation of test results for the Type A (CILRT) and Types B & C (Local Leak Rate Tests, LLRT), and a description of the licensee's efforts to improve containment integrity (ILRT/LLRT Betterment Program). Both Mass Point and Total Time calculational methods were employed for the December 1987 CILRT. The Total Time method of ANSI N45.4-1972 is consistent with the requirements of the current version of 10 CFR 50 Appendix J and is the method of record for the test.

The purpose of the test was to demonstrate that leakages through the primary containment building and systems penetrating containment do not exceed that allowed by plant technical specifications. The test was conducted with containment isolation valves (CIV's) and containment pressure boundaries (CPB's) in an "As-Left" condition. The containment could not meet the leakage criteria in the "As-Found" condition due to excessive local leakage. This has been acknowledged by the licensee and reported per the requirements of 10 CFR 50.73, Licensee Event Report (LER) system. The test was witnessed by an NRC regional inspector during a routine safety inspection and was followed by a successful verification test. Inspection findings are documented in USNRC Region I Inspection Report No. 50-293/87-58. Pertinent test parameters and results are presented below:

A. Type "A" Test Parameters and Acceptance Criteria

1.	Test Method	Absolute
2.	Calculational Methods	Total Time (per ANSI N45.4-1972) Mass Point (per ANSI/ANS 56.8-1987)
3.	Test Duration:	
	Stabilization Period	4 hours
	Data Gathering for Leakage Calculation	24 hours
	Verification Leak Rate Test	5 hours
4.	Test Pressure	59.69 psia (full pressure test)
5.	Maximum Allowable Leak Rate at upper bound of 95% confidence limit	0.750 wt. %/day

B. Test Results

Test Results	Wt. %/Day
Acceptance, maximum allowable leak rate	0.750
Measured Leak Rate, Lam for Total Time Method	0.189

Test Results	Wt. %/Day
Leak Rate at the Upper Bound of the 95% Confidence Interval	0.240
Total Corrections (Type B & C penalties and water levels)	0.010
Total Type "A" "As-Left" Leak Rate, Total Time Method	0.250
Conclusion	Acceptable in "As-Left" condition

The inspector concludes that, based on a review of the results, the containment has passed its acceptance criteria in the "As-Left" condition. Failure in the "As-Found" condition has been acknowledged and reported by the licensee.

4.0 Review of Plant Events

The inspectors followed up on events occurring during the period to determine if licensee response was thorough and effective. Independent reviews of the events were conducted to verify the accuracy and completeness of licensee information. During this period, the licensee made the following reports to the NRC pursuant to 10 CFR 50.72:

a. Reactor Water Cleanup System Spurious Isolation

On March 11, 1988, at 10:20 p.m., the licensee experienced an automatic closure of the inboard primary containment isolation valve on the reactor water cleanup (RWCU) system suction line. Investigation by the licensee indicated that the technicians performing a surveillance on the electrical portions of the system inadvertently grounded a wire which had been lifted during the surveillance test. Grounding the wire resulted in a blown logic power fuse, and deenergization of this portion of the logic caused the valve to automatically close. The fuse was replaced and the test subsequently completed.

The licensee's investigation concluded that the cause of the actuation was non-licensed utility technician personnel error. An Instrument and Control (I&C) technician was removing an area high temperature switch in the RWCU logic circuit for a routine calibration in accordance with the Procedure 8.M.2-1.2.2, "Reactor Water Cleanup Area High Temperature". Factors contributing to the error were the type of electrical connections involved with the work, and the gloves worn by the technician to perform the work. The gloves (i.e., inner cotton lining gloves and outer rubber gloves) affected the dexterity of the technician during the removal of a screw from the lug on a temperature switch lead.

A similar inadvertent isolation of the RWCU system occurred on December 17, 1987 during the performance of the Procedure 8.M.2-1.2.2. As a corrective action a revision to the Procedure 8.M.2-1.2.2 was under consideration to incorporate a request for removing the RWCU system from service when the area high temperature switches were to be calibrated. The licensee decision on this proposed revision had not been finalized at the time of this event. Since the revised procedure involves removing a normally operating system from service, it is considered only a short term corrective action. The licensee has initiated an Engineering Service Request to review possible change to the frequency for calibration of the area high temperature switches, and a possible modification of the temperature switches or temperature switch connections. The inspector had no further questions.

b. Spurious Secondary Containment Isolation

On March 31, 1988, at 12:42 p.m. an inadvertent secondary containment isolation and an automatic start of the "A" and "B" standby gas treatment trains occurred. A licensed operator performing a daily surveillance test of the refueling floor high radiation monitors failed to properly reset the downscale trip for two of the channels. When an upscale trip was inserted in a third channel the full isolation signal was generated, resulting in the actuations. The trips were reset and the system returned to normal a short time later. The NRC was informed of the actuations via ENS at 1:55 p.m. Licensee investigation identified that personnel error was the primary cause. Poor communications between control room personnel and a weak procedure were also found to be contributors. The licensee has counseled the operator involved. Control room communications is the subject of an ongoing licensee training program. In addition a review of the routine daily surveillance test procedure was initiated. The inspector had no further questions.

5.0 Review of Licensee Event Reports (LERs)

LERs submitted to NRC:RI were reviewed to verify that the details were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted onsite followup. The following LER's were reviewed:

LER No.	Event Date	Subject
87-007-00	10/18/87	Automatic Actuation of the Reactor Protection System Due to a Personnel Error.
87-008-00 87-008-01	10/15/87	Unplanned isolation of shutdown cooling during implementation of a modification. Immediate inspector followup of this actuation is described in inspection report 87-45. During inspection 87-50, the inspector noted that the LER identified personnel error as the primary root cause. Based on the licensee's own root cause evaluation the root cause was found to be procedural deficiency. The licensee committed to issue an updated LER. Subsequently, LER 87-008-001 was submitted.
87-009-00	10/23/87	Seismic Class I conduit routed through Class II area of the circulating water intake structure due to an original design deficiency. Existing unresolved item 87-34-01 was established to track NRC followup to this problem, and licensee evaluation of other Class II structures.
87-010-00	7/2/87	Full reactor scram signal due to a spurious trip of average power range monitor (APRM) "E". Immediate inspector followup of this actuation is described in inspection report 87-27. The actuation was not initially reported by the licensee as required by 10 CFR 50.73. This was identified by the inspectors and tracked as unresolved item 87-45-05. The licensee submitted LER 87-010 on November 20, 1987.

LER No.	Event Date	Subject
87-011-00	7/7/87	Full reactor scram signal due to a failed logic card. Inspector followup of this actuation is described in inspection report 87-27. An LER was not initially submitted by the licensee. LER 87-011 was subsequently issued in response to unresolved item 87-45-05 on November 24, 1987.
87-012-00	9/28/87	Full reactor scram signals due to spiking of intermediate range monitors. Inspector followup of these actuations is described in inspection report 87-45. A review conducted by the licensee in response to unresolved item 87-45-05 identified that the required LER was not submitted. LER 87-012 was subsequently issued on December 7, 1987.
87-013-00	11/8/87	Breaching of a security vital area boundary. Violation 87-50-02 is pending enforcement action in this area.
87-014-00 87-014-01	11/12/87	Loss of Offsite Power. An Augmented Inspection Team was dispatched in response to this event. Inspection results are documented in report 87-53.
87-015-00	12/7/87	Unplanned isolation of shutdown cooling during installation. Inspector followup of this actuation is described in inspection report 87-57.

LER No.	Event Date	Subject
87-016-00	11/24/87	Unplanned actuations of primary containment, secondary containment and standby gas treatment systems. Notice of Violation 87-50-07 was issued as a result of followup to this event.
87-017-00	11/25/87	Reclassification of a plant area as a security vital area. Unresolved Item 87-50-03 was opened to monitor licensee action in this area.

The inspector noted that the levels of detail, technical accuracy and the overall quality of LERs have improved during the last six months.

6.0 Management Meetings

At periodic intervals during the course of the inspection period, meetings were held with senior facility management to discuss the inspection scope and preliminary findings. A final exit interview was conducted by the resident inspectors to convey final inspection results and findings on May 9, 1988. No written material not already available to the public was provided to the licensee by the inspector. The inspector confirmed during the exit interview that no proprietary information was supplied by the licensee during the period.

Attachment I to Inspection Report No. 50-293/88-12

Persons Contacted

R. Bird, Senior Vice President - Nuclear
* K. Highfill, Station Director
R. Anderson, Plant Manager
E. Kraft, Plant Support Manager
F. Famulari, Quality Assurance Manager
A. Morisi, Planning and Outage Manager (Acting)
D. Swanson, Nuclear Engineering Department Manager
J. Alexander, Operations Section Manager
J. Jens, Radiological Protection Section Manager
J. Seery, Technical Section Manager
R. Grazio, Field Engineering Section Manager
P. Mastrangelo, Chief Operating Engineer
R. Sherry, Chief Maintenance Engineer
W. Mullins, Chief Radiological Engineer
D. Long, Security Section Manager
F. Wozniak, Fire Protection Division Manager

*Senior licensee representative present at the exit meeting.

ATTACHMENT II

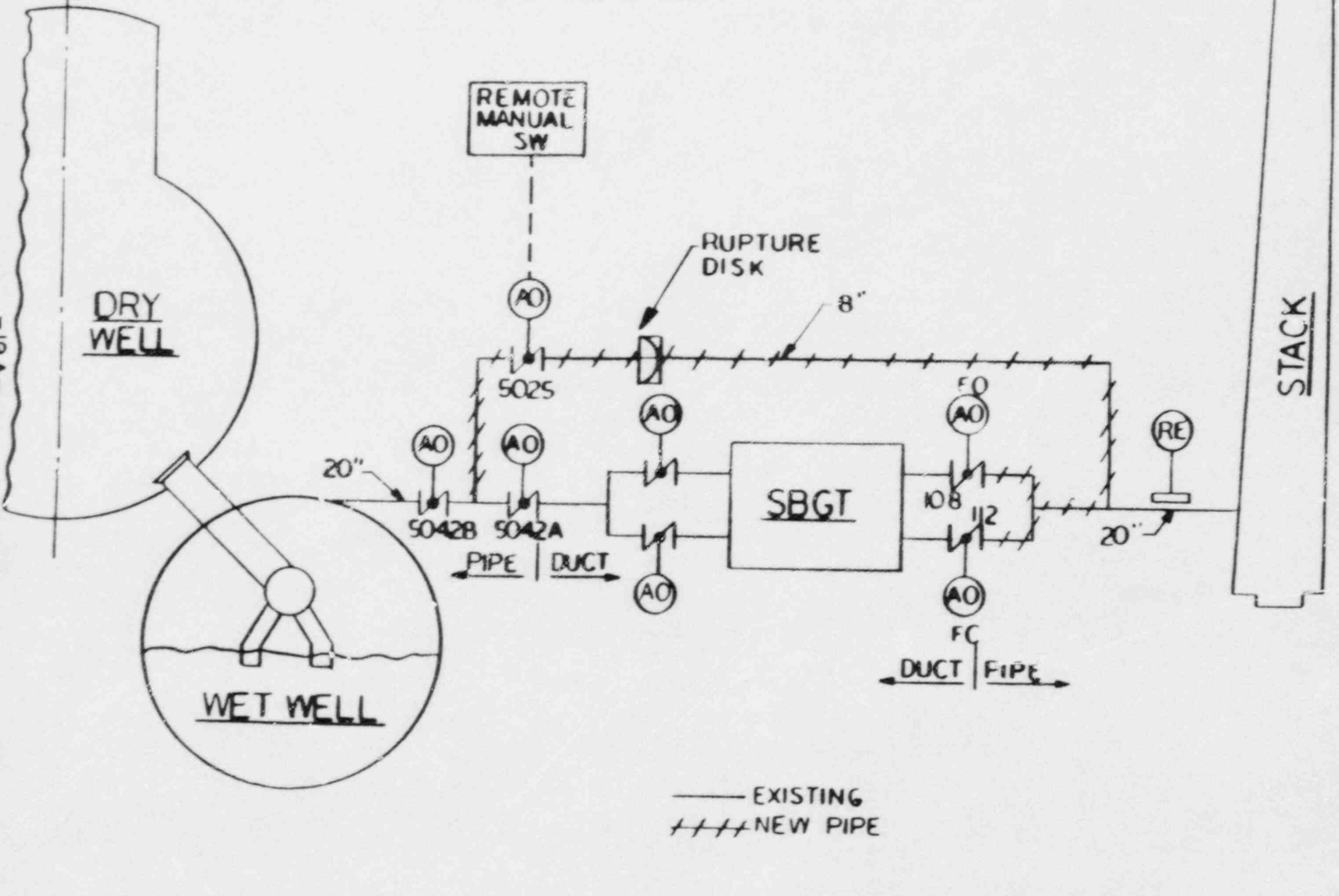
Direct Torus Vent Presentation Handouts

DIRECT TORUS VENT SYSTEM

- MEETS NRC REQUIREMENTS FOR SEALED CLOSED ISOLATION VALVE
- NO EFFECT ON DESIGN BASIS ACCIDENTS
- NO CHANGE TO TECHNICAL SPECIFICATIONS
- USE FULLY CONFORMS TO NRC APPROVED EPGs
- SIGNIFICANT IMPROVEMENT RELATIVE TO EXISTING VENT CAPABILITY

DIRECT TORUS VENT SYSTEM

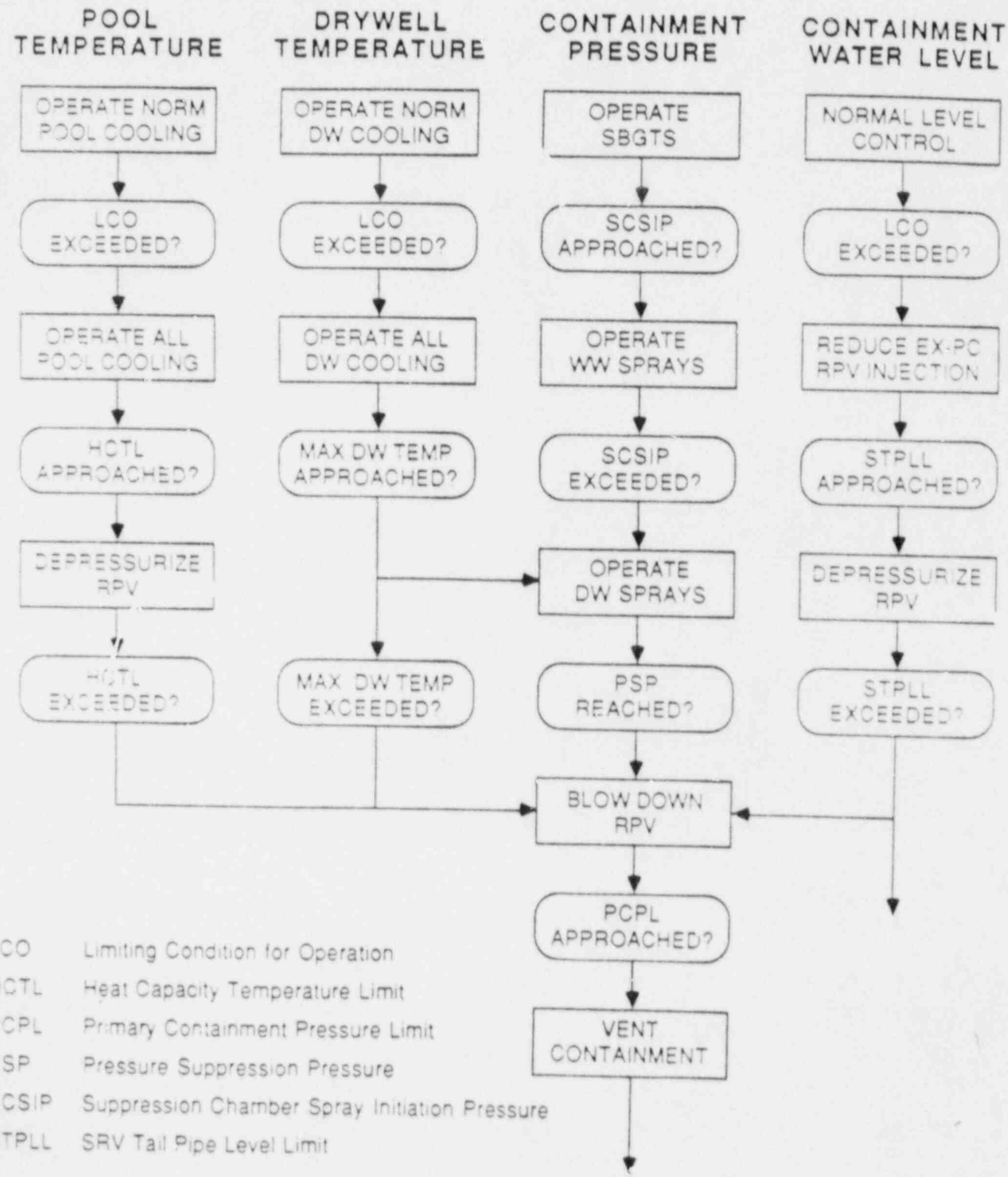
FIGURE 3.2-1



Basic Strategy of the EPGs

- Defense in depth
- Identify appropriate actions and limits in advance.
- Provide a graduated response keyed to certain important plant operating parameters.
- Prevent damage to either core or containment as long as possible.
- Maximize the time availablo to recover systems.
- Mitigate core damage.

Basic Primary Containment Control



LCO Limiting Condition for Operation
HCTL Heat Capacity Temperature Limit
PCPL Primary Containment Pressure Limit
PSP Pressure Suppression Pressure
SCSIP Suppression Chamber Spray Initiation Pressure
STPLL SRV Tail Pipe Level Limit

Primary containment venting is required for pressure control only:

- When all other decay heat removal mechanisms combined are inadequate.
- When primary containment pressure is well beyond that calculated for any design basis accident.
- When the structural capability of the containment is threatened, directly or indirectly.

When plant conditions have so degraded, the operating crew cannot reasonably rely upon a fortuitous turn of events to reverse the situation.

Not venting will, lacking the fortuitous turn of events, result in primary containment failure and most probably loss of adequate core cooling and core damage.

Venting will result in preservation of primary containment integrity for as long as possible and most probably continued adequate core cooling without core damage.

Plant Conditions Which Must Exist Before Venting

- Pool cooling unavailable/insufficient
- Drywell cooling unavailable/insufficient
- Wetwell sprays unavailable/insufficient
- Drywell sprays unavailable/insufficient
- Main condenser unavailable
- RPV depressurized
- Shutdown cooling unavailable/insufficient
- Primary containment pressure in excess of that calculated for any design basis accident

Potential Negative Impacts of Containment Venting:

- Pump NPSH reduction
- Subsequent de-inertion
- Inability to reclose the vent path
- Reactor building habitability degradation
- Inadvertent venting
- Premature venting

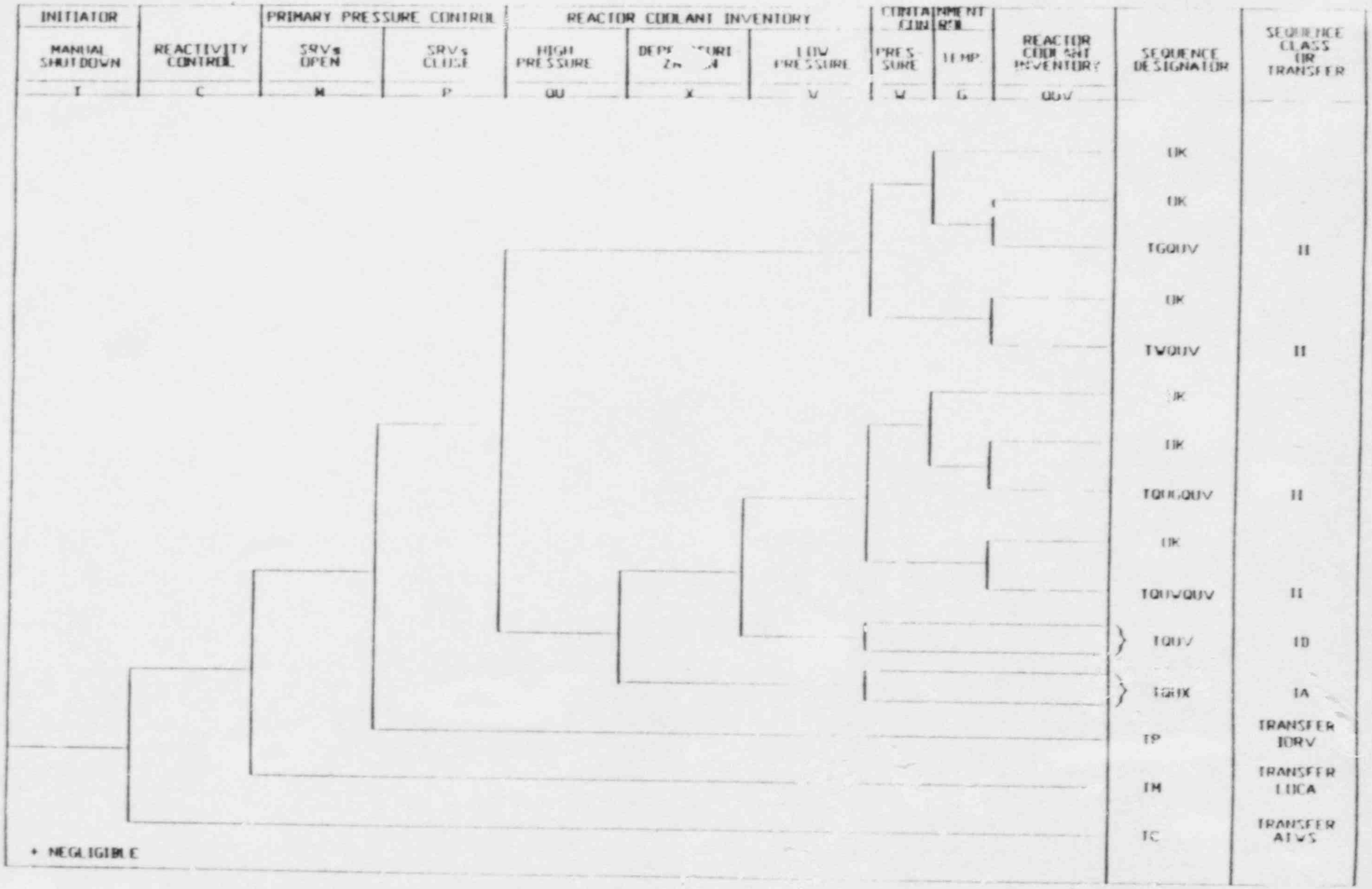


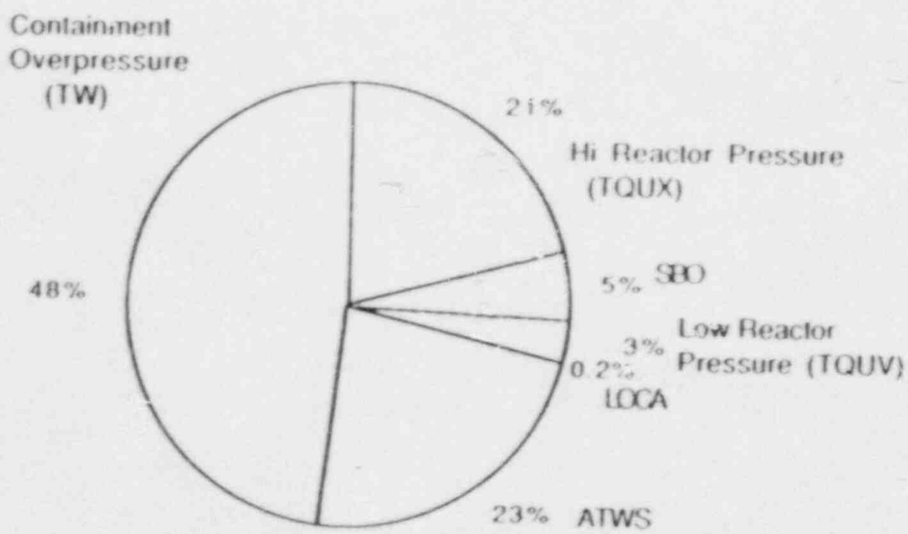
Figure 2 Transient Event Tree for Determining Potential for Significant Releases

S470035L

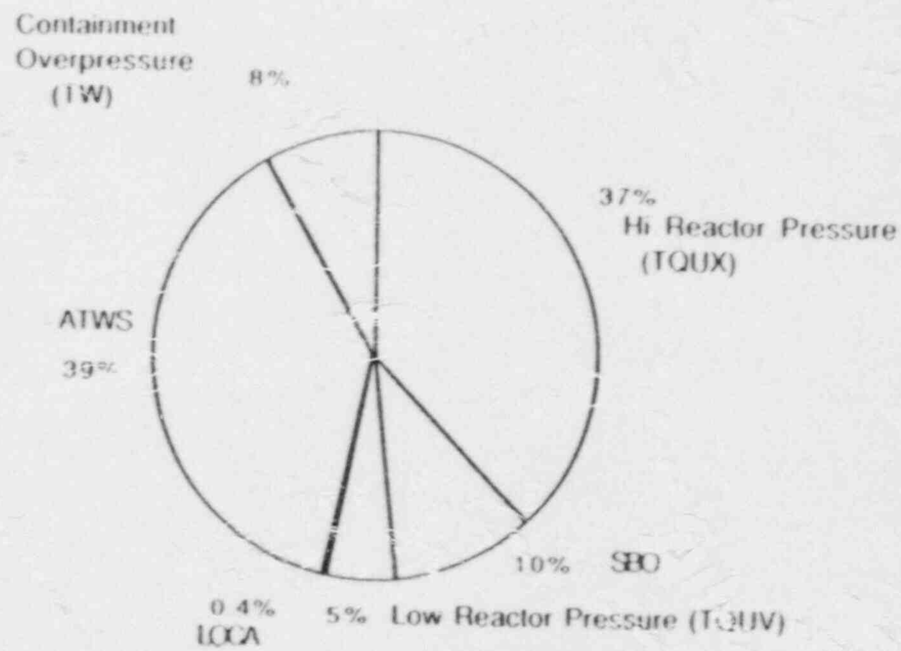
470013-035-11

PRELIMINARY

CORE DAMAGE FREQUENCY
PILGRIM IPE RESULTS



WITHOUT CONTAINMENT VENTING
CDF=4[illegible]e-5/yr



WITH CONTAINMENT VENTING
CDF=2.7E-5/yr

Table 1

PILGRIM DIRECT TORUS VENT SENSITIVITY STUDY
—SUMMARY OF RESULTS—

Frequency of Preventive Venting

TW Sequences
2.9E-4/Yr

Frequency of Mitigative Venting

Sequence Class	Containment PressureCtl	H_2 Ctl
TQUX	5.9E-9/Yr	9.1E-8/Yr
SBO	1.2E-6	2.3E-8
TQUV	2.8E-7	1.1E-8
AV	2.5E-8	1E-9
	1.5E-6/Yr	1.3E-7/Yr

	Core Damage Probability		Containment Release Probability		Dose Consequences*	
Sequence	Vent	No Vent	Vent	No Vent	Vent	No Vent
TQUX	9.1E-6/Yr	9.1E-6/Yr	1.4E-7/Yr	1.3E-7/Yr	1.3 R/Yr	1.3 R/Yr
SBO	2.3E-6	2.3E-6	1.2E-6	5.5E-7	0.5	5.5
TQUV	1.1E-6	1.1E-6	2.8E-7	1.6E-7	0.1	1.8
TWQUV	2.1E-6	2.1E-5	2.1E-6	2.1E-5	63	630
AV	1E-7	1E-7	2.4E-8	1.6E-8	.01	.16
Other	1E-5	1E-5	1E-5	1E-5	200	200
	2.5E-5/Yr	4.4E-5/Yr	1.4E-5/Yr	3.2E-5/Yr	260 R/Yr	840

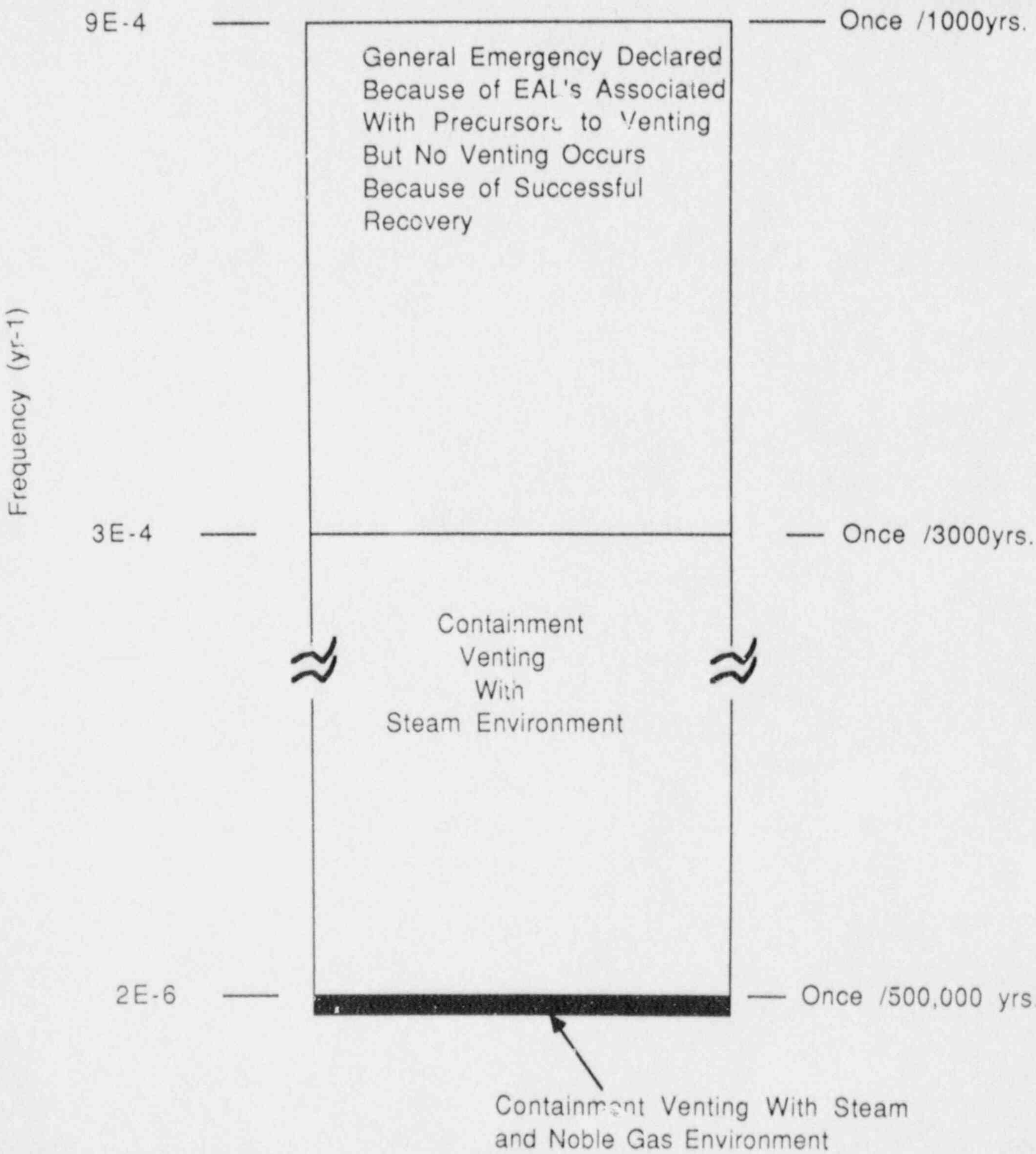
*Assumptions as to dose consequences by accident class (reference IDCOR 18.1 for Peach Bottom).

TW	3E+7R
Vent	4E+5R
ATWS	2E+7R
All others	1E+7R

b133

Preliminary

FREQUENCY of DECLARING GENERAL EMERGENCY



Preliminary

TRANSIENT TIME FRAMES for SEQUENCES LEADING to VENTING

	Containment Heat Removal (TW)	Station Blackout (SBO)	LOCA with Injection Failure (AV)
Core Uncovered		3 hr	~ 0 hr.
Vessel Failure		5.3 hr	1 hr.
Vent Pressure Pressure	32 hr.	18 hr	20 hr.
Ultimate	53 hr.	24 hr.	26 hr.

Venting under the plant conditions specified in the EOPs offers the following advantages over permitting containment failure:

- Slower energy release into areas where vent paths are directed minimizing environmental effects (Direct Torus Vent avoids steam release to reactor building altogether)
- Containment pressure control limiting NPSH concerns
- Controlled release rates to the environment retaining containment atmosphere to maximum extent practical and permitting termination once repair is effectiive.
- Maximize fission product scrubbing

Competing Risks associated with containment venting:

- Earlier releases provide less time for repair activities however,

  - Time available between venting presssure and containment i s not as large as that already available to effect repairs. Increased likelyhood of recovery during this period is small.

  - Ability of plant personnel to continue repairs in vicinity of containment once containment exceeds design pressure or core damage has occured is small,.

- Earlier releases provide less time for Emergency Plan Implementation

  Declaration of General Emergency and recommendations for protective actions are expected early in events which may lead to containment venting

EFFECT of SEP MODIFICATIONS

SEP Improvements	High Rx Press. TQUX	SBO	Low Rx Press. TQUV	Hi Cont. Press TWQUV	ATWS	S.A. Cont. Response
EOP's	X		X	X	X	X
Direct Torus Vent				X		
Fire Protection Sys.		X	X	X		X
3rd Diesel Gen		X				
Backup N2 Supply		X				
Containment Spray		X		X		X
ADS Logic					X	X
RCIC Turbine setpt				X		
ATWSMods.						
Enriched Boron					X	
RPT Reliability					X	
Feedwater Trip					X	
TRACG					X	

50.59 Considerations

Venting has been approved under previous versions of the EOPs. The direct torus vent is initiated by procedure under conditions specified by the EOPs and therefore no new accident is created by the installation or use of the direct torus vent.

A rupture disk set as low as 2.5psig (Group II isolation setpoint) is sufficient to assure that the direct torus vent will have no effect on the probability of occurrence or consequence of previously analyzed design basis events. In addition, that the outboard valve is sealed closed provides additional assurance that no previously analyzed event is affected.

The outboard valve for the direct torus vent meets the definition of a sealed closed valve and therefore no changes to the Pilgrim Technical Specifications are required.

Direct Torus Vent Description

The direct torus vent is hard piped to the stack bypassing the the ductwork of the Standby Gas Treatment System. The pneumatic supply to the valves is nitrogen thro DC operated solenoid valves.

To actuate the system

Symptoms as presented in Rev 4 of the BWROG EPGs must be present:

- Containment pressure in excess of that expected for any design basis event

- Substantial hydrogen generation during a period when the containment is deinerted

Operator must take multiple deliberate actions

- Jumper isolation signal to inboard valve (AO5042B)

- Install fuses in circuitry and acute keylock switch for outboard valve (AO5025)

EPG Accident Management Philosophies

Provide guidance to the operator as to the appropriate actions for any mechanically possible sequence of events regardless of likelihood or whether or not it is a part of the design basis

Provide a graded approach to protection of the core, containment and plant equipment as log as possible maximizing time for operator action and repair activities

Provide guidance for the purpose of core damage mitigation

Emergency Procedure Guidance with respect to Containment Venting

Venting for containment pressure control requires that

- Main condenser must be out of service

- Suppression pool cooling be unavailable or insufficient

- Drywell and wetwell sprays must be unavailable or inadequate

- Primary containment pressure must be greater than that expected for any design basis event

As a result, venting occurs only when other means of containment heat removal are inadequate and the structural integrity of containment is threatened.

Venting is initiated at this point to preclude more serious failures which are expected to occur if the containment is permitted to fail. As an example, venting under the conditions specified in the Emergency Procedures prevents core damage by precluding failure of the containment into the reactor building preserving the operability of core cooling equipment located in these areas.

Potential Negative Effects of Venting

- Pump NPSH reduction

- Subsequent deinertion

- Inability to close vent paths

- Degradation of reactor building environment

- Inadvertent venting

- Premature venting

It should be noted that for the most part these negative effects are also associated with containment failure and that an important aspect of venting is minimizing these effects to the maximum extent practical.

The only significant impact of the hard piped vent over other venting systems is in its ability to preclude degradation of the reactor building environment altogether. Inadvertent actuation of the the vent is is minimized by the deliberate multiple actions required for initiation and by the rupture disk.

Quantitative Evaluation of Venting

The preliminary results of the Pilgrim IPE were modified to evaluate the competing risks associated with containment venting. The general structure of the IPE event trees is shown and contains the following functional headings:

Reactivity control (reactor trip)

Reactor pressure control (safety valves)

Reactor inventory control (high and low pressure injection)

Containment control (containment temperature and pressure control)

Inventory makeup (reactor injection following containment failure)

Containment venting plays a role in the quantification of the containment pressure control heading. Other systems included in this heading are the main condenser, RHR, and containment sprays. The principal effect of venting is to reduce the frequency of sequences associated with containment pressure control failure (sequences TWQUV & TQUWQUV on the event tree diagram).

A secondary effect of containment venting is to mitigate offsite releases following core damage and coincidental failure of containment heat removal systems. The event tree diagram was modified to include a branch at the containment heat removal heading for core damage sequences TQUX and TQUV. In this way the IPE models could be used to evaluate not only the effect of containment venting on core damage, but on the potential for significant releases as well.

In this way, these negative effects are small as compared to the beneficial effects of venting in preserving adequate core cooling.

Overall effect of venting on core damage frequency

The primary purpose of venting as an accident management strategy is to protect core cooling equipment from the effects of uncontrolled failure of the containment into the reactor building. In this manner, venting can preserve core cooling during sequences in which containment pressure control systems are unavailable for an extended period.

To demonstrate this benefit graphically, a summary of the effects of venting on the Pilgrim core damage probability as estimated by the preliminary results of the IPE was presented in pie chart form. Without the capability to vent, containment heat removal failure sequences make up nearly half of the overall core damage probability. By permitting venting under the conditions specified by the Pilgrim Emergency Procedures, the frequency of core damage associated with containment heat removal failure sequences drops by an order of magnitude and the overall core damage probability is reduced by approximately 40%.

In this regard, containment venting as specified by the Emergency Procedures has a large beneficial effect on plant risk by effectively eliminating containment heat removal failure as an accident class.

Quantitative evaluation of competing risks

A more detailed quantitative breakdown of the competing risks associated with venting was presented in the form of Table 1 (Pilgrim Direct Torus Vent Sensitivity Study). Again, the preliminary results of the Pilgrim IPE were used as a basis for this analysis. The analysis presents information associated with the expected frequency of venting as well as the change in risk with and without the ability to vent. The analysis includes comparisons of competing risks not only for the purpose of preventing core damage, but evaluates the consequences of venting during post core damage conditions as well.

The following outlines several assumptions that were made which are important to to the outcome of the analysis. For the purpose of this analysis, conservative assumptions are defined as those which enhance the benefits of postponing or prohibiting containment venting, potentially nonconservative assumptions are those which favor venting. A discussion of the effects of the more important of these assumptions is presented as the results are examined.

Potentially Conservative Assumptions

- Repair and recovery activities are assumed to occur even after containment pressure rises above design or core damage occurs (in fact for personnel safety reasons, these activities may be terminated under these conditions whether or not venting is initiated)

- Credit is taken for use of core cooling systems located external to the reactor building following containment failure (this minimized the importance of the vent during containment heat removal failure sequences)

- A relatively high failure rate for the vent is assumed minimizing its effectiveness (this failure rate, .1/demand, is based on subjective evaluations which include reluctance of the operator to initiate venting because of steam and radionuclide release to the reactor building and environment or due to pressures from external sources such as the NRC and emergency response organizations)

- Consequence analyses assume complete depressurization of the containment on actuation of the vent, taking no credit for maintaining containment pressure with the vent (in accordance with Emergency Procedures) or terminating the vent once repair is effective.

Potentially nonconservative assumptions

- Little credit for repair of the main condenser is taken for sequences in which the main condenser fails randomly or is the initiating event (these sequences amount to 1/3 to 2/3 of containment heat removal failure sequences)

The upper half of Table 1 presents the expected frequency of containment venting for preventive (precluding core damage) and mitigative (post core damage) reasons. The results of the analysis indicate that venting for either reason is a rare event (on the order of 1/3000yr) and that venting under conditions in which significant radionuclides would be in the containment is extremely rare (less than 1/500,000yr). Mitigative venting is presented for the two purposes outlined in the Emergency Procedures, containment pressure control and combustible gas control. The frequency of venting for pressure control purposes is assumed to require failure of containment heat removal systems in addition to those system failures which lead to inadequate core cooling. For this reason, these frequencies are less than the frequency of core damage. Venting for hydrogen control purposes would be initiated only if core damage occurred coincidentally with the containment being deinerted. These frequencies therefore reflect the relatively small amount of time that the plant operates with the containment deinerted (approximately 1%). While the actual frequency of venting might be a factor of three or more less than suggested by this analysis (due to assumptions regarding recovery of the main condenser), these frequencies indicate that principal purpose of venting is for preventative reasons under conditions in which little or no core damage had occurred.

The bottom half of Table 1 presents a comparison of competing risks with and without containment venting as an accident management strategy. These risks include comparisons of core damage probability, the potential for significant releases from the containment and dose consequences.

The core damage probabilities are the same as those presented in the pie charts. Containment heat removal sequences (those labeled TWQUV) are the only sequences in which core damage probability is affected by containment venting. This is because other accident classes consider core damage for reasons other than containment heat removal failure and generally occur prior to containment overpressure due to decay heat generation. The likelihood of inadequate core cooling for these sequences is therefore unaffected by the presence or absence of containment pressure control systems. The core damage probability for containment heat removal failure sequences is substantially less than the frequency of venting for several reasons. First, containment failure is assumed to occur at the ultimate strength of the containment which is approximately twice the containment design pressure. As it takes longer to raise containment pressure to its ultimate capacity, there is more time for repair activities and hence a higher likelihood of recovering failed heat removal systems. The additional time for repair accounts for approximately a factor of two reduction in the core damage frequency as compared to the venting frequency. Second, it is assumed that even though the containment may fail due to loss of heat removal, there is a possibility that systems outside the reactor building will continue to be available to provide core cooling. These systems include the feedwater and fire systems and account for the majority of the difference between the venting frequency and the probability of core damage due to containment overpressure failure. If venting is successful, the assumption is made that containment failure and core damage can be avoided altogether. Therefore, the frequency of containment heat removal failure sequences shown in the column in which venting is permitted is not the core damage probability associated with venting but represents those sequences in which venting failed or was not initiated. The it is a factor of 10 less than the frequency of core damage in the no venting column reflects the assumption that the operator will be able to initiate venting successfully with a 90% likelihood of success. As noted in the discussion associated with the pie charts, the implementation of a venting strategy has a relatively significant effect on the reduction in core damage probability (approximately 40%) by effectively removing containment heat removal failure sequences as a risk contributor.

The center column in the bottom half of Table 1 represents the effects of venting on the potential for significant releases following an accident. For the purposes of this evaluation, the term significant release is defined as the release of fission products from the containment in the form of particles, volatiles or noble gases generated as a result of a core damage event. Given this definition, a significant release is assumed under any of three conditions; containment failure resulting in core damage (such as containment heat removal failure events, TWQUV), containment failure occurs following core damage or venting is initiated following core damage (the latter two represented by the TQUX, SBO, TQUV and AV accident classes). With this definition, the risks associated with venting earlier than if the containment were permitted to fail can be weighed against taking advantage of additional time to effect repair and recovery. A simple model was applied to these accident sequences to evaluate the potential for repair. The model is exponential, assumes a mean time to recovery of 19 hours and is similar to models derived in WASH-1400 for recovery of mechanical equipment. As expected, the effect of taking advantage of additional time for repair is a reduction in the potential for releases during some sequences. (It should be noted that one of the assumptions made in this analysis is that repair activities can continue even following events in which core damage has occurred. A more realistic assumption would be that much of this repair activity would have to be terminated for personnel safety reasons which would limit the difference between the vent and no-vent frequency for the potential of significant releases.) However, the accident class which reflects an improvement from implementation of venting is once again that which represents the containment heat removal failure scenarios which benefit by effectively eliminating the potential for core damage if venting is successfully initiated. As a result, while the frequency of release for some accident classes may improve by postponement of venting, the overall net effect of allowing venting to occur is a reduction in the potential for significant releases by preventing core damage during scenarios in which containment heat removal equipment failures might lead to containment failure.

The last column in Table 1 compares the risks associated with venting in terms of offsite consequences. For the purpose of this analysis, offsite dose was chosen as a measure of these consequences. A simple frequency times consequences analysis was performed to derive the values presented in this section of the table. The frequency of occurrence used was that derived in the potential for significant release section of the table. The dose consequences for each accident class are shown in the footnote in the lower left corner of the table. It should be noted that site specific dose consequences for the various accident classes have not been derived for Pilgrim. As a result, the values shown in Table 1 were borrowed from work performed as a part of IDCOR activities associated with resolving the Severe Accident Policy. While not derived for the Pilgrim Plant specifically, the relative difference in the dose for each of the accident classes should still provide a reasonable measure of the competing risks associated with venting. For this analysis, venting is assumed to occur through the suppression pool. For sequences in which the containment is challenged but not vented, containment failure is assumed to occur in the drywell. Sequences in which containment failure leads to core damage (TWQUV events) have a higher dose consequence than other sequences because core damage occurs within a containment which is already assumed to be failed. Comparing the consequences of permitting containment to fail as opposed to releasing through a vent path, most accident classes show a reduction in offsite consequences if venting is initiated to preclude containment failure. This is a result of the scrubbing which occurs through the containment vent path (which reduces releases to noble gases if it occurs through the suppression pool as preferentially directed by Emergency Procedures). The beneficial effects of scrubbing more than offset the perceived benefits of postponing releases in favor of repair activities for post core damage venting sequences. More importantly, once again, is the effect of venting on containment heat removal failure sequences. Venting effectively eliminates theses sequences as an accident class providing a significant reduction in the potential for offsite consequences.

Several assumptions were made in the analysis which may have an effect on the conclusions drawn as a result of the study. Among these assumptions were repair and recovery model characteristics, and postulated locations for containment failure and the vent path. Sensitivity studies were performed to determine the significance of these assumptions on the results. With respect to recovery models, it was determined that a mean time to recovery as short as several hours was required to balance the risks associated with venting early during post core damage events with the benefits derived by scrubbing. This unrealisticly short time for repair of major mechanical systems suggests that the results are relatively insensitive to assumptions made with respect to recovery models. A sensitivity analysis was also performed on the magnitude of reduction in offsite dose derived by venting. It was determined that dose reductions as small as a factor of two still resulted in a reduction in offsite consequences during post core damage events over letting the containment fail. Combined with the elimination of core damage sequences associated with containment heat removal failure, this suggests that even if the location of the containment failure happens to occur from an area such as the suppression pool airspace or if venting is initiated by paths such as from the drywell, it is still appropriate to vent as opposed to permitting containment failure.

Effect of Venting on Emergency Response

Declaration of a General Emergency is expected early in an event in which venting might be initiated. This is a result of the Emergency Action Levels associated with the Pilgrim Emergency Plan implementing procedures. Symptoms associated with these EALs include a loss of the ultimate heat sink and anticipation of containment pressure rising to above design pressure. Either of these symptoms would lead to a General Emergency whether or not offsite dose projections were in excess of protective action guidelines.

From the Pilgrim venting sensitivity analysis, the frequency of implementing the Emergency Plan was estimated for sequences in which venting might be initiated. These estimates indicated that a General Emergency would be declared on the order of 1/1000yr, that during a large fraction of these sequences recovery of containment heat removal equipment would preclude the need to vent (venting would occur on the order of only 1/3000yr) and that only the smallest fraction of those sequences would involve venting with fission products in the containment atmosphere as a result of a core damage situation (approximately 1/500,000yr).

Conclusions

The concept of venting is an accident management strategy available to a plant operating staff to protect the core and the containment under circumstances in which the structural integrity of the containment is threatened due to overpressure or the presence of combustible gases. Venting is a rare event requiring the occurrence of multiple failures coincident with an accident or transient and, as a result, is not expected to occur over the lifetime of any given plant. Implemented in accordance with the guidance provided in the BWR Owners Group EPGs, venting will occur only after other means of controlling conditions within the containment have been unsuccessful and and failure of the containment effectively appears to be inevitable. Venting in these circumstances offers the following advantages over permitting the containment to fail.

- Venting permits a slower energy release into areas in which vent paths are directed. This permits milder environments in areas such as the reactor building providing more assurance that equipment located in these areas will continue to operate than if the containment were permitted to fail in an uncontrolled manner. Venting with the direct torus vent precludes releases to the reactor building altogether.

- Venting allows the operator to control containment pressure. When performed in accordance with the instructions of the EPGs, use of the containment vent allows the operator to maintain pressure below the primary containment pressure limit. This is as opposed to the potential for uncontrolled depressurization of the containment if containment failure were to be permitted. By controlling containment pressure, the operator can minimize NPSH problems to the maximum degree that is practical providing more assurance that core cooling systems which are taking suction from the suppression pool can continue to operate.

- Venting permits controlled releases to the environment. Because the operator is able to maintain containment pressure through the use of venting equipment, release rates to the environment will be slower and over a longer duration than might occur if uncontrolled containment failure were permitted. This allows the retention of as much of the containment atmosphere as possible for as long as possible prior to its release. Controlling releases through venting equipment also has the advantage of being able to terminate releases altogether once repair activities are effective in returning failed containment control equipment to service.

- Venting maximizes the amount of fission product scrubbing that occurs along release paths. Venting hardware includes equipment associated systems such as containment purge and vent and the atmospheric control systems. These paths are fairly restrictive and provide additional surfaces on which filtering and plateout of volatile and nonvolatile fission products can occur. This effectively reduces the size of the radionuclide release which might occur if the containment were permitted to fail uncontrolled from an undefined location. When performed in accordance with Emergency Procedure Guidelines, venting is preferentially performed through the suppression pool. Controlling the release path in this manner provides a substantial degree of scrubbing, effectively limiting releases to noble gases.

While venting as opposed to permitting the containment to fail appears to have a number of advantages, it is recognized that there are competing risks associated with venting as an accident mitigation tool. One element of containment venting criteria as it is directed in the Emergency Procedures is that it be initiated prior to reaching the ultimate strength of the containment. Because there is margin between the criteria at which procedures suggest that venting be initiated and the ultimate capacity of the containment, there exists a limited number of scenarios in which repair activities may have resulted in recovery of failed systems and equipment after venting was initiated, but prior to the time that containment failure would have occurred. In this regard, there is a small likelihood that had venting not been initiated, releases would have been avoided and any fission products that were released to the containment during the course of the accident would have been retained. To some extent then, it would appear advantageous to postpone venting utilizing the additional time for repair of containment heat removal equipment or emergency planning.

- o Postponing containment venting to take advantage of additional time for repair activities may not enhance the likelihood of successfully recovering necessary equipment. This is particularly true if the systems under repair are located in areas in the vicinity of containment such as the reactor building. Conditions in these areas associated with the accident or as the containment exceeded design conditions would not necessarily permit the operating staff to occupy these areas for personnel safety reasons, limiting time for repair and recovery whether or not venting was initiated.

  In addition, analysis of these scenarios indicates that the amount of time which is gained by postponing venting is less than that which is already available to perform repair activities prior to reaching the venting criteria. The increase in the likelihood that equipment repair will be successful in the time frame subsequent to reaching venting criteria is considered to be small given that repairs were unsuccessful up to this point. This suggests that the benefits of postponing venting are limited when compared to the advantages outlined above.

- o With respect to Emergency Plan activation it is likely that conditions leading to the need to vent the containment will result in declaration of a General Emergency early in the event. This is a result of Emergency Plan implementing procedures which have been developed in accordance with NUREG-0654. These procedures require declaration of an emergency based on certain symptoms and combinations of equipment failures which would occur during a transient in which venting might ultimately be required. Such events include LOCAs with ECCS failure, LOCAs with unsuccessful containment performance which could threaten

ECCS functions and loss of heat removal capabilities following shutdown. Because of the structure of Emergency Plan procedures in this regard, notification of the public and recommendations for protective action are expected early in an event in which venting might be initiated.

In summary, containment venting is an accident management strategy intended to prevent or minimize the consequences of transient and accident events in which containment conditions are approaching limits at which failure is anticipated. Under these rare circumstances, venting provides an additional opportunity for the operating staff to intervene in the course of the accident, control the location and rate at which any releases might occur, and terminate those releases once repair activities are effected. The advantages associated with venting in this manner outweigh the potential disadvantages of releasing the containment atmosphere in a time frame slightly earlier than if the containment were permitted to fail. While not expected to be required over the lifetime of of the plant, venting is the appropriate course of action under conditions specified by the Emergency Operating Procedures to reduce the potential for core damage and to minimize offsite consequences. Venting can be initiated by several means at the Pilgrim Plant. Venting from the suppression pool with the direct torus vent maximizes scrubbing and limits any offsite releases to the maximum extent practical. Use of the hard piped vent also limits uncertainties associated with releases of steam to areas outside containment associated with other vent paths.