UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

February 4, 2005

EA-05-001

Mr. William Levis
Senior Vice President and Chief Nuclear Officer
PSEG Nuclear LLC - N09
P. O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: HOPE CREEK NUCLEAR GENERATING STATION - NRC SPECIAL INSPECTION TEAM REPORT NO. 05000354/2004013 AND PRELIMINARY WHITE FINDING

Dear Mr. Levis:

On December 16, 2004, the US Nuclear Regulatory Commission (NRC) completed a Special Inspection at the Hope Creek Nuclear Power Plant. The enclosed report documents the inspection findings which were discussed with members of your staff during a public exit meeting on January 12, 2005.

This inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The team reviewed selected procedures and records, observed activities, and interviewed personnel. In particular, the inspection reviewed your investigation, root cause evaluations, relevant performance history, extent of condition, potential common cause failures, and corrective actions associated with the failure of an 8-inch diameter moisture separator drain tank line on October 10, 2004. The team also independently evaluated the equipment and human performance issues that complicated the event response, and evaluated the associated radiological release.

The team concluded that PSEG's overall response to the October 10, 2004, event was adequate, although the operators were challenged by equipment problems. The team concluded that none of the problems would have prevented the systems from performing their intended safety functions.

This report documents one finding that appears to have low to moderate safety significance. As described in Section 3.3 of this report, this finding involved inadequate evaluation and corrective action for a degraded level control valve for the 'A' moisture separator drain tank. The valve malfunctioned several weeks prior to the event and caused the moisture separator drain system to operate outside its design. This condition resulted in a pipe failure in a moisture separator drain line on October 10, 2004. In addition to the inadequate evaluation of the level control valve malfunction weeks before the event, engineers also did not properly consider a similar occurrence from 1988.

This finding was assessed using the reactor safety Significance Determination Process (SDP) as a potentially safety significant finding that was preliminarily determined to be White (i.e., a finding with some increased importance to safety, which may require additional NRC inspection). The finding appears to have low to moderate safety significance because the condition of the level control valve increased the potential for a plant transient that included the loss of the normal power conversion system (the main condenser).

We believe that we have sufficient information to make our final risk determination for the performance issue regarding the inadequate evaluation and corrective action for the level control valve that malfunctioned. However, before the NRC makes a final decision on this matter, we are providing you an opportunity to either submit a written response, or to request a Regulatory Conference where you would be able to provide your perspectives on the significance of the finding and the bases for your position. If you choose to request a Regulatory Conference, it should be held within 30 days of the receipt of this letter, and we encourage you to submit your evaluation and any differences with the NRC evaluation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. The NRC will also issue a press release to announce the Regulatory Conference. If you decide to submit only a written response, such submittal should be sent to the NRC within 30 days of the receipt of this letter.

Please contact Mr. Raymond Lorson at (610) 337-5282 within 10 days of the date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision and you will be advised by separate correspondence of the results of our deliberations on this matter.

Additionally, based on the results of this inspection, the team identified three findings of very low safety significance (Green). Two of these issues were determined to involve violations of NRC requirements. However, because of their very low safety significance, and because they have been entered into your corrective action program, the NRC is treating these issues as non-cited violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny the non-cited violations noted in this report, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Hope Creek facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

If you have any questions, please contact Mr. Raymond K. Lorson at (610) 337-5282.

Sincerely,

/RA/

Wayne D. Lanning, Director
Division of Reactor Safety

Docket No. 50-354
License No. NPF-57

Enclosure: Inspection Report 05000354/2004013
w/Attachments

cc w/encl:
G. Barnes, Site Vice President
M. Brothers, Vice President - Nuclear Assessment
M. Gallagher, Vice President - Engineering and Technical Support
W. F. Sperry, Director - Business Support
C. Perino, Director - Regulatory Assurance
M. Massaro, Hope Creek Plant Manager
R. Kankus, Joint Owner Affairs
J. J. Keenan, Esquire
M. Wetterhahn, Esquire
Consumer Advocate, Office of Consumer Advocate
F. Pompper, Chief of Police and Emergency Management Coordinator
J. Lipoti, Ph.D., Assistant Director of Radiation Programs, State of New Jersey
K. Tosch - Chief, Bureau of Nuclear Engineering, NJ Dept. of Environmental Protection
H. Otto, Ph.D., DNREC Division of Water Resources, State of Delaware
N. Cohen, Coordinator - Unplug Salem Campaign
W. Costanzo, Technical Advisor - Jersey Shore Nuclear Watch
E. Zobian, Coordinator - Jersey Shore Anti Nuclear Alliance

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.	50-354
License No.	NPF-57
Report No.	05000354/2004013
Licensee:	PSEG, LLC
Facility:	Hope Creek Nuclear Power Plant
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	October 14, 2004 - December 16, 2004
Inspectors:	S. Pindale, Senior Reactor Inspector (Team Leader) S. Dennis, Senior Operations Engineer T. Burns, Reactor Inspector E. Knutson, Resident Inspector J. Wiebe, Reactor Inspector R. Davis, Materials Engineer J. Furia, Senior Health Physicist N. McNamara, Emergency Preparedness Specialist W. Schmidt, Senior Reactor Analyst
Approved by:	Wayne D. Lanning, Director Division of Reactor Safety

Enclosure

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000354/2004013, 10/14/04 -10/22/04, 11/29/04 -12/03/04, 12/15/04 -12/16/04; Hope Creek Nuclear Power Plant; Special Inspection Team.

This inspection was conducted by full-time and part-time team members, including six regional inspectors, a resident inspector, a regional senior reactor analyst, and an engineer from the Office of Nuclear Reactor Regulation. One finding, assessed as a Preliminary White, and three other Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3 dated July 2000.

A. NRC Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Preliminary White. A finding of low to moderate safety significance was identified where engineering staff did not properly evaluate and correct a degraded level control valve for the ‘A’ moisture separator drain tank, as required by station procedures. In addition, engineers did not properly consider a similar occurrence from 1988. The level control valve failed 25 days prior to the event and caused the moisture separator drain system to operate in a condition outside its design. As a result, an 8-inch pipe in that system failed and caused the event on October 10, 2004.

  This issue is greater than minor because it is associated with the Equipment Performance attribute of the Initiating Events cornerstone and affected the objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions. A Significance Determination Process Phase 2 risk analysis determined that this finding had low to moderate safety significance based on the increased frequency of a transient with the loss of the power conversion system initiating event over the 25-day exposure period. (Section 3.3)

Cornerstone: Mitigating Systems

- Green. A finding was identified as a result of the October 10, 2004, event, and was a non-cited violation of 10 CFR Part 50, Appendix B, Criterion V (Instructions, Procedures, and Drawings). Technicians did not comply with a procedure to properly set a limit switch on a high pressure coolant injection (HPCI) system injection valve, which is interlocked with the HPCI full flow test valve. As a result, the full flow test valve did not open as required on initial demand when control room operators attempted to place the HPCI system in the pressure control mode of operation. Operators were subsequently successful in opening the valve about five minutes later after additional actions were taken.

  This finding is greater than minor because it is associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and affects the cornerstone's objective to maintain mitigation equipment reliable. This finding is of very low safety significance because the finding did not represent the actual loss of the safety function for the HPCI system. Also, reactor pressure remained relatively stable when the issue occurred and alternate pressure control methods were available (safety relief valves) if required. (Section 2.2.1)

- Green. A finding was identified as a result of the October 10, 2004, event, and was a non-cited violation of 10 CFR Part 50, Appendix B, Criterion V (Instructions, Procedures, and Drawings) in that procedures for operating the reactor core isolation cooling (RCIC) system at low flow conditions were inadequate. As a result, while operating the RCIC system during a plant transient, the system exhibited unexpected flow oscillations in the automatic mode when control room operators ran the system at low flow conditions.

  This finding is greater than minor because it is associated with the Procedure Quality attribute of the Mitigating Systems cornerstone and affects the cornerstone's objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences. This finding is of very low safety significance because the finding did not result in the actual loss of the safety function for the RCIC system. Also, reactor vessel level was maintained in the appropriate range in accordance with procedures and the HPCI system was available for reactor vessel level makeup if required. (Section 2.2.2)

- Green. A finding was identified as a result of the October 10, 2004, event in that PSEG did not effectively implement preventive maintenance for the HPCI system barometric condenser vacuum pump. As a result, with the HPCI system operating in the pressure control mode, the vacuum pump tripped twice due to improper lubrication of the vacuum pump shaft. Due to the vacuum pump failure, operators removed the HPCI system from service and continued a vessel cooldown with alternate safety related equipment (safety relief valves).

  The finding is greater than minor because it is associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and affects the cornerstone's objective of ensuring the reliability of systems that respond to initiating events. The finding is of very low safety significance because per design basis, with the vacuum pump not available, the HPCI system remained operable and was able to perform its mitigation function if required.
  (Section 2.2.3)

REPORT DETAILS

1.0 EVENT DESCRIPTION

1.1 Event Summary: October 10, 2004, Manual Reactor Scram[1]

On October 10, 2004, at approximately 6:00 p.m., control room operators lowered reactor power from 100% in response to a substantial increase in main condenser offgas system flow and a coincident turbine building ventilation exhaust radiation monitor alarm due to a reported steam leak in the turbine building. Initially, condenser vacuum was able to be maintained by the steam jet air ejectors (SJAE). While not immediately known to the operators at that time, a pipe failure had occurred in the drain line from the 'A' moisture separator (MS), which discharges to the main condenser. At 6:14 p.m., because offgas flow continued to increase and steam was noted in the condenser bay area of the turbine building, control room operators initiated a manual reactor shutdown (scram) and main turbine trip to reduce the potential consequences of the steam leak. Following the scram and turbine trip, main condenser vacuum began to decrease rapidly. In anticipation of the consequential loss of 1) the normal heat sink (main condenser), and 2) normal reactor vessel level control with the feedwater pumps (steam/turbine driven), the operators manually opened the turbine bypass valves (while the condenser was still available) in an attempt to lower reactor pressure to the point (less than 650 psig) where the condensate pumps would be able to provide water to the reactor.

As condenser vacuum continued to degrade, the feedwater pumps tripped (as expected) on a low condenser vacuum signal before reactor pressure could be lowered to the point where the condensate pumps could be used; and reactor vessel level began to lower due to the resulting reduction in reactor vessel level makeup. In an effort to maintain reactor vessel inventory, the operators closed the bypass valves and manually initiated the reactor core isolation cooling (RCIC) system to maintain reactor vessel level within the desired level control band. While the operators were in the process of manually placing the RCIC system in-service, the high pressure coolant injection (HPCI) system automatically initiated when reactor vessel[2] reached the point at which both RCIC and HPCI automatically start (Level 2).

Reactor vessel level began to recover from the Level 2 setpoint (the lowest vessel level reached during the transient) with RCIC, and HPCI was secured from reactor vessel injection. Condenser vacuum continued to degrade and the operators manually closed the main steam isolation valves (MSIV) in anticipation of an automatic close signal due to low vacuum. Further operations with the MSIVs closed complicated the post scram reactor vessel water level and pressure control because the main condenser is the normal source for heat removal. The operators attempted to place HPCI in service in the pressure control mode of operation, however, they were delayed for less than 10 minutes due to a valve interlock issue that was subsequently resolved. As reactor vessel level returned to the normal range, the operators reduced RCIC flow to maintain

---

[1]See Attachment C for a detailed Sequence of Events for the October 10, 2004, event.

[2]See Attachment E for a discussion on reactor water level setpoints and definitions.

the desired level band and noticed that flow oscillations were occurring with the RCIC system. As reactor pressure was lowered with HPCI (in pressure control mode), reactor vessel level control was transitioned to the condensate system, and RCIC was removed from service.

A normal reactor cooldown rate was established with HPCI until a subsequent equipment issue (vacuum pump trip) resulted in HPCI being removed from service. The cooldown was successfully re-established using the safety relief valves (SRV). Additionally, as expected during RCIC and HPCI operation, suppression pool temperature increased and the operators placed the residual heat removal (RHR) system in-service, as directed by emergency operating procedures (EOP). The RHR system remained in service in the suppression pool cooling mode of operation as the cooldown continued with the SRVs. Operators stabilized the plant in Hot Shutdown (average coolant temperature > 200F) at 10:11 p.m. on October 10. The RHR system was subsequently placed in the shutdown cooling mode of operation, and the plant was placed in Cold Shutdown (average temperature ≤ 200F) at 5:09 a.m. on October 12.

During the initial event and subsequent cooldown, reactor vessel water level cycled in response to various plant conditions and operator actions, including main turbine bypass valve operation, reset of the scram signal, initiation of RCIC and HPCI, and SRV cycling. Additionally, during the event, the operators noted equipment operational issues with the reactor water cleanup (RWCU), RCIC, and HPCI systems.

The source of the steam leak was the failure of an 8-inch pipe from the ‘A’ MS drain tank line to the main condenser. This failure was the cause for the initial steam leak and subsequent rapid decrease in condenser vacuum. Post-scram review identified that a level control valve (LV-1039A) associated with the ‘A’ MS drain tank had been open in excess of three weeks, and was the direct cause for the pipe failure. In addition, a spring can pipe hanger (H25), designed to provide support for an upstream portion of the failed pipe, was found to have been disconnected. An extension rod, associated with hanger H25, had worn a hole in the air supply line to LV-1039A due to vibration over an extended period of time (several years) which caused the LV-1039A valve to fail open.[3]

There were no injuries associated with this event. There was a minor radiation release from the plant that was well below approved regulatory limits. The majority of this release was monitored by the turbine building exhaust and south plant ventilation stack radiation monitors.

Operator performance issues and challenges are discussed in Section 2.1; and specific equipment issues are discussed in Section 2.2.

---

[3]See Attachment D for a MS/drain system and level control valve issue chronology.

2.0 PLANT RESPONSE: PERSONNEL AND EQUIPMENT

2.1 Operator Performance and Training

a. Inspection Scope

The team reviewed and assessed licensed operator performance during the transient and manual reactor scram caused by the pipe failure, including reactor vessel level and pressure control and the subsequent plant cooldown. In particular, the team focused on the plant response as reactor vessel level dropped below the Level 2 setpoint for a short period of time. The team reviewed and evaluated the operators' use and adherence to normal, abnormal, and emergency procedures during transient mitigation and subsequent plant operations. Additionally, the team assessed adherence to Technical Specifications and compliance with associated Limiting Conditions of Operations (LCO).

The team interviewed all licensed operators involved in the event to assess operator performance during the transient and during subsequent operations to cold shutdown. Items reviewed included the following:

- operator logs;
- narrow and wide range reactor vessel water level graphs;
- sequence of events computer printout;
- narrow and wide range reactor pressure graphs;
- HPCI and RCIC pump discharge flows; and
- PSEG's root cause evaluations.

The team also reviewed operator actions and communications that occurred during shift turnover, after the plant had been stabilized in a Hot Shutdown condition, and during the subsequent plant depressurization and cooldown.

The team reviewed the dynamic response of plant systems, evaluated the transient response of critical plant parameters, and reviewed the actions taken by the operators in order to determine if any significant issues existed in the areas of simulator fidelity or operator training. In particular, the team reviewed PSEG's evaluations regarding HPCI system operation during the plant depressurization and cooldown; RCIC system operation during the transient when operators observed system flow oscillations; and conditions which led to the trip of the 'B' RWCU pump during plant depressurization.

In addition, the team reviewed two PSEG Root Cause Analysis Reports associated with operational aspects of the events. Specifically, one Root Cause Investigation Report (Notification/Condition Report 20206606/70041900) evaluated Technical Specification management; and another Root Cause Investigation Report (Notification/Condition Report 20206631/70041930) evaluated reactor vessel water level control difficulties.

b. Findings

No findings of significance were identified. Several observations and one minor violation are discussed in the following sections.

1. General - Transient Response and Procedure Adherence

The team found that the on-shift crew displayed adequate command and control during the initial transient response. Actions directed by the control room supervisor (CRS) and taken by the board operators were in accordance with procedures. The team also noted that extra personnel (from the oncoming shift) were utilized in the field to ascertain the cause of the transient and were effective in communicating pertinent plant condition information to the CRS and shift manager (SM). The team found that operators entered the appropriate abnormal and emergency procedures as the event progressed and as plant conditions changed. The team also found the operators followed procedural guidance in order to maintain reactor vessel level within the prescribed ranges, however, the operators were challenged in this area due to equipment performance issues.

2. Reactor Vessel Level and Pressure Control

The team found that operators controlled reactor vessel pressure in the required range during the transient and subsequent reactor vessel cooldown to Cold Shutdown. The team also found that the operators' ability to control reactor pressure was affected by mitigation system operational issues (HPCI, RCIC); these equipment issues are discussed in Section 2.2. Regarding reactor vessel level control, the team found that on five occasions, reactor vessel level was outside the normal transient response level band of Level 3 (+12.5 inches) to Level 8 (+54 inches) as prescribed in the EOPs. Each of the five occasions is described and assessed below. See Attachment E for detailed information regarding reactor vessel level setpoints, instruments, and definitions. As a reference, Level 2 (-38 inches), which was the lowest level reached during this transient, is about 10 feet above the top of the active fuel (which is at -161 inches).

- *October 10, 2004 at 6:19 p.m.- Level 2 Automatic Engineered Safety Feature Initiation and Isolation Signal:* Following the initial manual scram and with main condenser vacuum rapidly degrading, the CRS, anticipating the eventual loss of the turbine driven reactor feedwater pumps (RFP) on low condenser vacuum, directed the reactor operators to open the main turbine bypass valves to reduce reactor pressure to between 600 and 700 psig from approximately 920 psig. That pressure band was chosen to enable feeding the reactor vessel with the condensate system pumps (motor driven), whose shutoff head is approximately 650 psig. As vacuum continued to degrade and just prior to the loss of the RFPs on low condenser vacuum, the CRS directed closure of the bypass valves. The CRS stated that due to the imminent loss of the RFPs, the action to close the bypass valves was intended to preserve reactor vessel inventory. At that time, reactor pressure was not low enough for the condensate system to provide makeup to the reactor vessel, so the CRS directed manual initiation of the HPCI and RCIC systems to restore vessel level.

The closure of the bypass valves caused an increase in reactor vessel pressure and a corresponding shrink in vessel level. The bypass valve closure and associated level shrink combined with the loss of the RFPs caused vessel level to decrease to Level 2. As the Level 2 setpoint approached, operators manually initiated RCIC, and HPCI automatically initiated at the Level 2 setpoint. Reactor vessel level began to increase immediately upon reaching the Level 2 setpoint, and the operators began to restore reactor vessel level with RCIC to a normal band of between Level 3 and Level 8, as directed by EOPs, and secured HPCI injection flow for use in the pressure control mode. The HPCI system was needed for pressure control because the MSIVs were manually closed (due to the rapidly degrading condenser vacuum) and therefore, the turbine bypass valves were not available for pressure control.

The team found that the actions directed by the CRS and taken by the control room operators were in accordance with abnormal and emergency procedures. The operators stated the magnitude of the vessel shrink and inventory loss with bypass valve operation appeared to be larger in the plant than in the simulator.

- *October 10, 2004 at 6:46 p.m. - Level 3 Automatic Reactor Scram Signal During Plant Stabilization:* As reactor vessel level recovered to the normal band with RCIC, HPCI was placed in the pressure control mode of operation. With reactor vessel level rising to within the normal band of Level 3 to Level 8, the operators reduced RCIC system injection flow to maintain the normal band. However, as RCIC flow was reduced, the RCIC system began to experience flow oscillations. This condition was unexpected by the operators and after about two minutes of continuous oscillations, RCIC was placed in a minimum flow condition. Reactor vessel level peaked at about +30 inches before beginning a slow trend downward with HPCI in the pressure control mode. With reactor vessel level approaching +20 inches, the operators returned RCIC to service at a reduced flow rate (350 gpm) in order to maintain a controlled reactor vessel level increase. However, at this reduced flow rate, RCIC flow oscillations occurred again (See Section 2.2.2 for a detailed discussion on the RCIC flow oscillations).

  Since plant conditions were stable, including reactor vessel level (at about +30 inches), a decision was made to reset the reactor protection system (RPS) Level 3 scram signal, as directed by plant procedures. The scram signal and RPS were reset, however, the decision to reset the scram was not communicated to the operators controlling reactor vessel level (with RCIC) and pressure (with HPCI). Following the scram reset, a slow downward reactor vessel level trend commenced due to 1) the steam demand from HPCI in the pressure control mode (which was more pronounced than the operators had expected); 2) the unexpected flow oscillations with the RCIC system, and 3) the termination of control rod drive system flow to the reactor vessel (of which the operators controlling level were not aware). Consequently, in less than two minutes after the scram reset, reactor vessel level had reached the Level 3 setpoint, and an automatic RPS scram signal occurred (as designed). The operators responded promptly to the scram signal and restored level back to the normal band by increasing RCIC injection flow. Reactor vessel level reached a minimum of +10 inches before being restored to above Level 3.

The team reviewed the operators actions leading to the RPS actuation and concluded there were control room communications and assessment weaknesses. Although several operators were aware that the scram signal was being reset, the operators directly involved with reactor vessel level and pressure control were unaware of the decision. The team found that operator distractions caused by the RCIC system flow oscillations and underestimation of the steam demand associated with the HPCI system in the pressure control mode contributed to the weakness in assessment and communications.

- *October 10, 2004 at 9:38 p.m. - Level 8 Automatic Overfill Protection During Plant Cooldown:* With HPCI in the pressure control mode of operation, reactor pressure at 400 psig, and reactor vessel level at +25 inches on the narrow range scale, the HPCI barometric condenser vacuum pump circuit breaker opened (tripped). The operators placed RCIC in service in the pressure control mode of operation in anticipation of removing HPCI from service due to the vacuum pump trip. The vacuum pump breaker's thermal overload device had actuated (indicating excessive electrical current), and after no apparent cause for the trip was found, operators reset the breaker (permitted by procedure) and the pump was restarted. After approximately five minutes of successful HPCI vacuum pump operation, RCIC was removed from service. However, after about ten additional minutes of HPCI operation, the vacuum pump breaker tripped again, and the operators removed the HPCI pump from service (See Section 2.2.1 for a detailed discussion of the HPCI vacuum pump issue).

  The RCIC system was again placed in the pressure control mode, however, the RCIC system capacity was insufficient to continue to reduce reactor pressure, which began to slowly increase (RCIC capacity is about 10% of the HPCI system capacity). During this period, reactor vessel level increased to approximately +42 inches on the narrow range instruments; which equated to approximately +54 inches (Level 8) on the wide range vessel level instruments at this reduced pressure of 400 psig. Level 8 on the wide range instruments initiates a RCIC trip signal, and a Level 8 trip of RCIC occurred as designed.

  As described in Attachment E, the discrepancy between wide and narrow range level indication during the reactor coolant system cooldown is expected due to changes in the density of the reactor vessel inventory as the cooldown progressed. This was expected by the operators due to the known deviations between narrow and wide range level instruments experienced during a reactor vessel depressurization and cooldown. The team noted that once level decreased below Level 8, the operators again placed RCIC in the pressure control mode but its capacity was unable to reduce pressure. The operators then removed RCIC from service and recommenced the plant cooldown with SRVs to control pressure and the condensate system to control level. The team found these actions to be acceptable. The team found that given the equipment operational issues with HPCI and the challenges of maintaining reactor vessel level in the required band during vessel cooldown, the operators took appropriate actions in accordance with procedures.

- *October 10, 2004 at 9:57 p.m. - Level 3 Automatic Scram Signal During Reactor Cooldown:* After RCIC tripped in response to the Level 8 signal noted above, operators continued the cooldown with SRVs as directed by operating procedures. Safety relief valve F013R was manually opened with reactor pressure at 475 psig and remained open for approximately nine minutes until reactor pressure reached approximately 350 psig. Reactor vessel level had increased as expected due to level swell when the SRV was opened. Then, the reactor vessel level began to decrease (due to the inventory reduction from the open SRV), and the operators closed the SRV when reactor vessel level was at about +25 inches on the narrow range level indicator. When the SRV went fully shut, a level shrink occurred as expected and narrow range level decreased to approximately +7 inches, which is below the Level 3 RPS trip setpoint; and an RPS actuation occurred. The operators promptly recovered reactor vessel level above the trip setpoint using the condensate system.

  The team reviewed the actions of the operators regarding the use of the SRVs for pressure control and found that the actions taken were in accordance with procedures. The team found that the operators discussed the effects of SRV use on reactor level and had established a level band which they believed, based on training experience, would have precluded reaching the Level 3 RPS actuation setpoint. The operators informed the team that although training is performed requiring SRV usage, it is not typically performed at the lower reactor pressures experienced in this transient. The team also noted that while using SRVs during the remainder of cooldown, the operators maintained a higher reactor level band, and no further Level 3 RPS actuation occurred.

- *October 10, 2004 at 10:04 p.m. - Level 8 Automatic Overfill Protection During Plant Cooldown:* Due to the dynamic vessel response and the Level 3 RPS actuation that occurred while using the SRVs for pressure control, the operators placed the RCIC system in service in the pressure control mode to continue the reactor vessel cooldown. However, as previously experienced, RCIC (in pressure control mode) was not able to effectively reduce reactor pressure due to its relatively small capacity; and reactor vessel level and pressure began to slowly rise. Once reactor level reached +42 inches on the narrow range level instruments (about Level 8 on the wide range level instruments at this low pressure), the RCIC turbine tripped as expected. The operators then continued the cooldown with SRVs while maintaining the previously established level band. With this higher level band on the narrow range (to avoid reaching the Level 3 RPS setpoint), a Level 8 trip signal resulted on the wide range level instruments.

The team reviewed the operators actions regarding control of the reactor coolant system cooldown with RCIC and SRVs and found their actions to be in accordance with procedures. The team found that due to the inability of the RCIC system to effectively maintain a cooldown and the dynamic response on vessel level due to operation of the SRVs, the operators' decision to maintain a higher band on the narrow range vessel level was appropriate. The team also noted that although operating experience existed regarding SRV usage and the dynamic effects on reactor vessel, PSEG did not effectively utilize this information in classroom or simulator training for the operators. PSEG initiated Notification 20212885 to address this apparent weakness associated with the operating experience program.

3. Training and Simulator Fidelity

Based on review of the event, associated documents, and interviews of operators, the team found that simulator modeling and operator training was a factor in the following areas:

- The response of reactor pressure/level during cycling of turbine bypass valves and SRVs was more pronounced in the plant than in the simulator.

- The RCIC system exhibited flow oscillations while in automatic under low flow conditions (about 350 gpm). The simulator did not model this known system operational challenge; and operators and personnel responsible for simulator modeling/training were not aware that the system may experience flow oscillations under low flow/automatic control conditions. This was a procedure inadequacy issue related to operating experience and is discussed further in Section 2.2.2.

- The steam demand of the HPCI system (in pressure control) and the affect on reactor vessel level was more pronounced in the plant than in the simulator.

- Steam leak training scenarios did not typically carry the transient through the transition from Hot Shutdown to Cold Shutdown with the use of SRVs or HPCI for the cooldown.

- When the steam leak initially occurred, the steam jet air ejectors (SJAE) were initially able to maintain condenser vacuum as reactor power was decreased. For similar simulator scenarios, based upon operator interviews and discussions with simulator personnel, the SJAEs were not modeled to maintain condenser vacuum once a steam leak occurred.

The team found that although the operators encountered plant transient responses which differed slightly from the simulator response they experienced in operator training, they were able to operate safety systems and other plant equipment in accordance with procedures to safely mitigate the transient. The team found that PSEG's review of training and simulator issues was adequate, including corrective actions; and that the issues were entered into the corrective action system (Notification No. 20212476).

4. Technical Specification Misinterpretation

The NRC identified that operators misinterpreted Technical Specification (TS) 3.6.2.3, which is associated with the residual heat removal (RHR) system. The reactor scram occurred at 6:14 p.m. on October 10, 2004. During the transient response and as directed by procedures, the operators placed both loops of the RHR system in the suppression pool cooling mode of operation (a secondary mode of operation) at 6:31 p.m. The primary mode of operation for RHR is the standby alignment for accident response in the low pressure coolant injection mode. In accordance with the existing requirements described in procedure, SH.OP-AP.ZZ-0108(Q), “Operability Assessment and Equipment Control Program,” the affected RHR loops were declared inoperable.

The Action Statement for TS 3.6.2.3 requires operators to place the plant in at least Hot Shutdown within 12 hours and in Cold Shutdown within the next 24 hours. Operators determined that since the TS LCO had been entered on October 10 at 6:31 p.m., the requirement to place the plant in Cold Shutdown had to be satisfied within 36 hours (12 hours added to 24 hours). Operators planned a controlled plant cooldown such that Cold Shutdown would be reached prior to exceeding the 36 hours. The operators achieved Cold Shutdown on October 12 at 5:09 a.m., about 34.5 hours after the TS Limiting Condition for Operation (LCO) was initially entered.

However, recognizing that the plant was already in Hot Shutdown at 6:31 p.m. when the TS LCO was entered (as a result of the reactor scram), the NRC questioned operators why they were not in the 24-hour LCO Action Statement. Subsequently, PSEG determined that the potential existed for a missed TS Action Statement and a one hour report to the NRC, for after-the-fact discovery for this issue, was initiated on October 12 at 7:45 p.m. (NRC Event Notification 41117). The team concluded that operators misinterpreted, and therefore, did not comply with TS 3.6.2.3 to place the plant into Cold Shutdown within 24 hours of declaring the RHR system inoperable.

The RHR system had been declared inoperable to address a generic concern regarding a postulated scenario involving a simultaneous design basis loss of coolant accident and loss of power event that could result in a water hammer upon the subsequent restart of the RHR system. This issue was identified in response to concerns regarding long term operation of the RHR system in the suppression cooling mode. However, the team noted that the postulated scenario described above was not required to be considered for short term operation of the RHR system in the suppression pool cooling mode (reference: Response to Task Interface Agreement 2001-14 dated April 28, 2003). Additionally, during this event, the system remained available for all modes of RHR operation. Accordingly, the team concluded that the TS mis-interpretation problem was a violation of minor significance not subject to formal enforcement action in accordance with Section IV of the NRC's Enforcement Policy. PSEG documented the problem in their corrective action program as Notification 20206606.

2.2 Equipment Performance

a. Inspection Scope

The team reviewed system and equipment performance issues as they related to the ability of the operators to effectively mitigate the transient and place the plant in a Cold Shutdown condition as required by Technical Specifications. The team reviewed operator logs, operating and emergency procedures, plant data, and interviewed personnel. The team also reviewed prior equipment performance, including maintenance and testing aspects, to determine whether there were prior opportunities to identify the problems; and reviewed PSEG's evaluation of the specific deficiencies.

b. Findings

Three self-revealing Green findings and two observations are documented in the following sections.

1. HPCI Full Flow Test Valve - Failure to Open on Demand

Introduction. A self-revealing finding of very low safety significance (Green) was identified associated with the HPCI system full flow test valve. A related HPCI injection valve limit switch was incorrectly set, resulting in the failure of the full flow test valve to open upon demand. The issue was determined to be a non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion V (Instructions, Procedures, and Drawings).

Description. While responding to the October 10, 2004, event, operators placed the HPCI system in a standby alignment after its automatic initiation and were in the process of placing the system in a full flow test (pressure control) mode to begin a reactor vessel cooldown in accordance with EOPs. When the operator attempted to open the HPCI full flow test valve F008, it failed to open. The operators made three additional attempts to open the valve without success.

The operators then checked the system lineup, which included verifying that HPCI injection valves F006 and HV-8278 were both closed. These valves are interlocked with the F008 and must both be closed to permit the opening of F008. Although F006 and HV8278 indicated closed (close light on), the operator depressed both valves' close pushbuttons in an attempt to ensure the interlocks were satisfied for the F008 valve to open. The operator again attempted to open valve F008 and was successful. The HPCI system was then successfully placed in the pressure control mode of operation (within ten minutes).

PSEG determined that F008 failed to open on demand due to an improper adjustment of the limit switch on valve HV-8278. The HV-8278 limit switch was in the open position with the valve actually in the closed position; and, therefore, the interlock with F008 was not satisfied. The closure of HV-8278 is controlled by the motor operator torque switch (i.e., valve travel stops when the torque switch is actuated). Due to the improperly set limit switch, the limit switch contacts did not actuate when valve travel stopped. This condition was not previously identified during routine HV-8278 and F008 testing because prior testing was done under static (no flow) conditions, and the limit switch had actuated before valve travel stopped. During the event, HV-8278 was closed while there was still HPCI system flow in the injection line (dynamic conditions), and the torque switch stopped valve travel slightly sooner due to the higher loading than would have been experienced under static conditions. The valve was closed, however, it was not seated enough to allow the limit switch to actuate. The limit switch and torque switch settings are such that, if set properly, the limit switch would actuate under both static and dynamic conditions.

Depressing and holding the closed pushbutton on HV-8278 overrides the torque switch, and the valve motor operator will continue to run until the limit switch actuates. Following the failed attempts to open F008, control room operators took this action to depress the close pushbutton for HV-8278, which produced enough additional stem travel to activate the limit switch.

In evaluating this issue, PSEG identified that the limit switch for the HV-8278 was last set on May 2, 2003, however, it was not set in accordance with procedural requirements as stated in SH.MD-EU.ZZ-0011(Q), "VOTES Data Acquisition for Motor Operated Valves." Additionally, PSEG determined that the engineering review of the procedure results failed to identify the discrepancy in the limit switch settings.

The team found that the technicians did not properly set the HV-8278 limit switch in accordance with the procedure. The team also found that engineers did not perform an adequate review of the completed procedure, as required. These failures led to a delay, of less than ten minutes, in placing the HPCI system in-service when it was required for transient event mitigation. The team also found that, while the periodic static testing of the valves did not identify this discrepancy, the valve's motor operator design (including the proper limit and torque switch settings and sequencing) ensures valve operation under both static and dynamic conditions. Due to system design and configuration, it is not practical to dynamically test the HPCI injection valves as it would require HPCI injection flow to the reactor. The team noted that operation of the HPCI in its safety mode (i.e. injection) was not affected by this problem.

<u>Analysis</u>. The team concluded that the performance deficiency was that plant personnel did not correctly perform procedure SH.MD-EU.ZZ-0011(Q). Specifically, the technician incorrectly set the limit switch for HPCI valve HV-8278 on May 2, 2003. The team also considered that this finding was indicative of a cross-cutting weakness in the area of human performance (personnel). Additionally, the required engineering review of the completed procedure did not identify this discrepancy, which was indicative of a cross-cutting weakness in the area of problem identification and resolution (identification). The valve failure led to a delay, of less than ten minutes, in the operators placing the HPCI system in-service when it was desired for event mitigation.

This self-revealing finding was greater than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to maintain mitigation equipment reliable. The team reviewed this finding using the Phase 1 Significance Determination Process (SDP) worksheet for mitigating systems and determined the finding was of very low safety significance (Green), because the finding did not represent the actual loss of the safety function of the HPCI system. Also, reactor pressure remained relatively stable when the issue occurred and alternate pressure control methods were available (SRVs) if required.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V (Instructions, Procedures, and Drawings) requires that, "activities affecting quality shall be prescribed by documented instructions and procedures appropriate to the circumstance and shall be accomplished in accordance with these instructions." Contrary to the above, PSEG procedure SH.MD-EU.ZZ-0011(Q) was not accomplished in accordance with the instructions delineated in the procedure. Specifically, Attachment 10 of the procedure was performed incorrectly on May 2, 2003, on valve HV-8278. This incorrectly performed procedure led to the failure of the F008 valve to open on demand during a transient on October 10, 2004. However, because the violation was of very low safety significance and PSEG entered the deficiency into their corrective action program under Notifications 20210277 and 20206665, and Order 70041898, this finding is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000354/2004013-01, Failure to Properly Set Limit Switch Settings on HPCI Injection Valve in Accordance with Procedures)**

2. RCIC System Flow Oscillations

Introduction. A self-revealing finding of very low safety significance (Green) was identified associated with the operation of the RCIC system. Industry operating experience regarding flow limitations while operating the system in the automatic mode of operation were not incorporated into operating procedures or training. The issue was determined to be an NCV of 10 CFR Part 50, Appendix B, Criterion V (Instructions, Procedures, and Drawings).

Description. During the response to the October 10, 2004, event, operators were in the process of recovering reactor vessel level with the RCIC system in the automatic mode of operation (flow control) and in accordance with EOPs. Operators noted system flow oscillations as they reduced RCIC flow to maintain reactor water level in the normal range of Level 3 to Level 8. The operators had not seen this system condition before, either in actual use or in simulator training, and the oscillating flow caused a slight delay (about 2-3 minutes) in restoring vessel level above the scram setpoint at Level 3.

PSEG's root cause evaluation identified that operating experience (OE) existed in the turbine vendor document (VTD 323601), which described the condition observed by the operators, and cautioned against operating the RCIC system in automatic under lower flow conditions. As stated in the vendor manual, the RCIC system design basis is to deliver a constant flow rate (600 gpm) in the automatic control mode to the reactor vessel over a wide range of reactor pressures. However, reducing system flow to below 75% of rated flow (about 450 gpm) in the automatic control mode promotes the likelihood of flow instability. In the event the instability occurs, it was recommended that the system be placed in the manual mode of operation (speed control).

The team found that these cautions and limitations were not incorporated into the RCIC operating procedure and therefore were unknown to the operators; and were also unknown to the operations training department.

Analysis. The team concluded that the performance deficiency was that existing vendor guidance had not been incorporated into the RCIC system procedure. Specifically, procedure cautions and limitations did not discuss the potential for system oscillations if flow was reduced in the automatic mode of operation. The team considered that this finding was indicative of a cross-cutting weakness in the area of problem identification and resolution (identification). Additionally, the failure to incorporate operating and vendor information into procedures and training was indicative of a cross-cutting weakness in the area of human performance (organization). The failure to incorporate the information led to mis-operation of the system in the automatic mode of operation and a slight delay in restoring reactor vessel level above the scram setpoint of +12.5 inches (Level 3). This self-revealing finding was more than minor because it was associated with the Procedure Quality attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences. The team reviewed this finding using the Phase 1 SDP worksheet for mitigating systems and determined the finding was of very low safety significance (Green), because the finding did not result in the actual loss of the safety function for the RCIC system. Also reactor vessel level was maintained in the appropriate range in accordance with procedures and the HPCI system was available for reactor vessel level makeup if required.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V (Instructions, Procedures, and Drawings) requires that, “activities affecting quality shall be prescribed by documented instructions and procedures appropriate to the circumstance and shall be accomplished in accordance with these instructions.” Contrary to the above, PSEG procedure HC.OP-SO.BD-0001(Q), “Reactor Core Isolation Cooling System,” did not include RCIC system operating and vendor information which specified cautions and limitations for system operation in the automatic mode. This led to the inappropriate operation of the RCIC system when it was needed for transient event mitigation. However, because the violation was of very low safety significance and PSEG entered the deficiency into their corrective action program under Notification 20206783 and Order 70041898, this finding is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000354/2004013-02, Failure to Incorporate Operating Experience for Low Flow Operations of RCIC Into Operating Procedures and Operator Training)**

3. HPCI System Barometric Condenser Vacuum Pump Trip

Introduction. A self-revealing finding of very low safety significance (Green) was identified associated with the HPCI system barometric condenser vacuum pump. Because of inadequate preventive maintenance on the vacuum pump assembly, operators removed the HPCI system from service during a plant event after it had been operating for reactor vessel depressurization and cooldown.

Description. While the HPCI system was operating during the October 10, 2004 event, the HPCI barometric condenser vacuum pump circuit breaker opened (tripped). The vacuum pump breaker's thermal overload device had actuated (indicating excessive electrical current). Upon initial investigation, there was no apparent reason for the trip and the breaker was reset and the vacuum pump restarted (permitted by procedure). The pump circuit breaker tripped again a few minutes later, at which time the operators elected to remove the HPCI system from service and continue the cooldown using the SRVs.

The team reviewed PSEG's evaluation of the issue in the root cause report (Order 70041898) which determined that preventive maintenance instructions for the pump specified the incorrect lubricant, which led to pump shaft binding and ultimately to a thermal overload trip of the pump circuit breaker while the pump was in-service. Specifically, in the lubrication information specified for the pump, a thread sealant was specified as the lubricant to be installed into the vacuum pump stuffing box instead of the correct lubricant, which was a multi-purpose lithium grease as specified by the pump manufacturer. Additionally, PSEG found that the packing gland follower on the pump was corroded, resulting in binding on the shaft sleeve.

The team also found that a previous trip of the HPCI system vacuum pump breaker had occurred on July 6, 2004 (Notification 20195868). At that time, the only corrective action taken was to visually check the pump and breaker for apparent problems. Because no problems were apparent, the operators reset the breaker, started the vacuum pump, and ran the HPCI quarterly surveillance test successfully (Procedure HC.OP-ST.BJ-0001(Q)). The corrective actions were closed to a trend status following a shift manager (licensed SRO) review. The team reviewed the corrective actions resulting from the current issue, which included an extent of condition review to include a cross-section of procedures used at Hope Creek and Salem to ensure that they were appropriately detailed and contain the correct technical information. Immediate corrective actions included re-building the HPCI vacuum pump, and re-packing and re-greasing the RCIC vacuum pump (which also contained the wrong lubricant but had not been adversely affected). The team determined that the corrective actions were adequate.

Analysis. The team concluded that the performance deficiency was ineffective implementation of preventive maintenance program for the HPCI barometric condenser vacuum pump, which led to a pump failure. In particular, the pump preventive maintenance instructions (Procedure PM031777, and the associated lubrication screen from the computer-based information tool) were inadequate in that the incorrect lubricant was specified. This led to pump shaft binding and ultimately a thermal overload trip of the pump circuit breaker while the pump was in-service. Additionally, the team concluded that corrective actions from a similar pump trip in July 2004 did not prevent recurrence of the problem. The team considered that this finding was indicative of cross-cutting weaknesses in the area of human performance (organization) and problem identification and resolution (corrective action).

The team noted that the vacuum pump is non-safety related support system equipment for the HPCI pump. Due to the pump failure, operators removed the HPCI system from service and continued a vessel cooldown with SRVs. The finding is greater than minor because it is associated with the Equipment Performance-Maintenance attribute of the Mitigating Systems cornerstone and it affects the associated cornerstone objective of ensuring the reliability of systems that respond to initiating events. The finding is of very low safety significance (Green) because per design basis, with the vacuum pump not available, the HPCI system remained operable and was able to perform its mitigation function if required. This issue has been entered into PSEG's corrective action program as Notifications 20206604, 20206634, and 20212882; and Order 70041898.

Enforcement. No violation of NRC regulatory requirements was identified. Although PSEG did not effectively implement its preventive maintenance program related to the HPCI barometric condenser vacuum pump, which is a non-safety related piece of equipment, this aspect of the preventive maintenance program is not an NRC regulatory requirement. **(FIN 05000354/2004013-03, Failure to Effectively Implement the Preventive Maintenance Program for the HPCI Barometric Condenser Vacuum Pump)**

4. Reactor Water Cleanup System Pump Trip

The team reviewed the details associated with the trip of the 'B' RWCU pump during October 10, 2004, plant depressurization. The team noted that the nuclear industry has identified a generic phenomenon associated with RWCU pump trips during reactor coolant system depressurization. This known issue had been placed on the Hope Creek operations work-around list as a problem that may degrade the operators' ability to respond to a transient.

The phenomenon involves flashing in the instrumentation line during transient depressurization conditions that may result in low pump suction flow being sensed by the transmitter, which in turn will cause a trip of the operating RWCU pump. PSEG determined during their review of operating experience and through concerns discussed at Boiling Water Reactor (BWR) Owners Group meetings, that this issue was present in several other BWRs. In response to previous RWCU pump trips at Hope Creek, and as indicated by operating experience, PSEG had implemented actions since 2001 to vent the instrument lines to the flow transmitter to remove entrapped gases. This appeared to temporarily fix the problem, and the system operated satisfactorily until a March 2003 pump trip. Based upon additional industry initiatives and correspondence, PSEG initiated several additional corrective actions following a subsequent April 2003 trip. These proposed actions included revising station procedures to better control system flow in plant startup and shutdown conditions, re-sloping the instrument tubing lines, and physically moving the pump suction venturi to a lower elevation.

The team found that during the October 10, 2004, event, the RWCU system (a non-safety related system) was not required for transient mitigation. Based upon the inclusion of the RWCU on the operator work-around list and the planned and completed corrective actions, the team concluded that PSEG efforts to date to address industry concerns associated with the RWCU pumps appeared reasonable.

5. Low Reactor Vessel Level Instrument Actuations/Logic

The team found that as reactor vessel reached Level 2 (-38 inches), two of the four wide range level instrument channels tripped (channels A and B) and then vessel level recovered above the Level 2 setpoint. Level channels C and D did not trip. All four of the level channels provide inputs to the logic for the redundant reactivity control system, the primary containment isolation system, the nuclear steam supply shutoff system, the HPCI system, and the RCIC system. The team reviewed the plant computer and instrument calibration data and found that the level differences sensed between each of the level channels were within the calibration tolerances permitted by plant procedures. Additionally, the team noted that the calibration tests for each of the level instruments had been performed within the required frequency. The team performed a detailed review of the systems mentioned above and found that isolations, actuations, and initiations had occurred as expected due to trip of level channels A and B. The isolations, actuations, and initiations which occurred included:

- HPCI pump initiation;
- Primary containment isolation valve closures;
- RWCU pump suction valve closure; and
- Filtration recirculation ventilation system fans automatically started.

The team also reviewed and verified that the operators performed system lineup verifications as provided in PSEG procedures HC.OP-AB.CONT-0002(Q), "Primary Containment," and HC.OP-SO.SM-0001, "Isolation Systems Operation," to identify that the isolations, actuations, and initiations caused by the level channel trip signals occurred as expected.

The team noted that PSEG identified that level inputs to some of the control room computer display system (CRIDS) reactor level display points were outside the tolerances recommended by the vendor. The team verified through review of instrument drawings, that the level inputs for CRIDS were unrelated to the level inputs for system isolations, actuations, and initiations, and were used for indication only.

The team also reviewed Notifications 20214768 and 20214655, which documented the engineering analysis used to evaluate the differences between the reactor vessel levels sensed by each of the four level channels. The analysis focused on thermal error, physical error, design margins, setpoints, and allowable instrument drift for each of the channels for both wide and narrow range instruments. The analysis concluded that the level discrepancies which occurred were in all cases either within the error assumptions of the setpoint calculations or within the available margins to the analytical limits.

The team determined, based on the information reviewed, that the reactor vessel level trip systems functioned as designed and that the isolations, actuations, and initiations that occurred due to the trip of level channels A and B were appropriate. The team also reviewed PSEG's recommended actions intended to achieve better accuracy in the level inputs to the CRIDS system and found them to be adequate. The corrective actions related to the above referenced notifications were also reviewed by the team, and found to be adequate.

2.3 Radiological Release Assessment

a. Inspection Scope

The team reviewed data and calculations used to quantify the amount of radioactive material released following the pipe break and subsequent steam release from the turbine building on October 10, 2004.

b. Findings

PSEG evaluated the radiological release associated with the event and concluded that the amount of radioactive material released and its impact on the maximally exposed individual were both below regulatory limits. The team reviewed PSEG's analyses and conducted independent assessment, and confirmed that the radiological release was below regulatory limits.

PSEG technicians obtained two grab samples during the transient, and generated two gaseous radioactive waste release permits. These permits were accompanied by calculations on the quantity of radioactive materials released and the impact on the maximally exposed individual at or beyond the site boundary. The maximum calculated exposure from beta and gamma radiation dose from noble gases was less than 0.01% of the limit set forth in PSEG's Offsite Dose Calculation Manual (ODCM) Section 3/4.11.2.2 for quarterly dose limit. The maximum calculated organ dose was 0.74% of the quarterly limit and 1.02% of the annual limit for the thyroid set forth in ODCM section 3/4.11.2.3 for exposure from radio-iodines and particulates.

PSEG determined that the total amount of radioactivity released (about 9.2 Curies of noble gas) consisted of both monitored and unmonitored releases (9.1 Curies was monitored via the South Plant Vent, and an estimated 0.1 Curies was unmonitored). PSEG determined this information by completing an analysis of the release data and plant parameters to assess the radiological consequences. The time frame analyzed for the total radiological release was from about 5:35 p.m. on October 10, 2004, to about 8:30 a.m., on October 11, 2004 (about 15 hours). Operators tripped the turbine about two minutes after the scram (6:15 p.m. on October 10, 2004), which is when the source of the steam was isolated. PSEG determined that for the same time analyzed (15 hours), a normal discharge of noble gas through the south plant vent (normal turbine building release point) would have been about 4.9 Curies. Therefore, PSEG determined that the event resulted in an additional 4.3 Curies of noble gas than would have been released during normal plant operations (9.2 minus 4.9).

As part of PSEG's review, they also evaluated the radiological impact and conducted a bounding assessment of a potential unmonitored release. This was done because there was anecdotal evidence that the turbine building pressure went slightly positive for several minutes shortly after the pipe failed (the turbine building pressure is normally slightly negative relative to atmospheric pressure). For example, there were reports by station personnel that there was condensation/water droplets outside the turbine building, at building penetrations (doors and material joints). Notification No. 20207055 was written to document this condensation outside the turbine building. Although no activity was detected in the water droplets, their presence tends to indicate that at some time during the steam release within the turbine building, the building pressure was not negative to atmosphere. PSEG bounded the time that the building may have been slightly positive to be less than one hour (until the steam leak was isolated). In that time, PSEG calculated the total noble gas quantity within the released steam to be 0.1 Curies.

The team reviewed PSEG's analyses, including assumptions and radiological data and surveys. The team determined that PSEG's results and assessments of the radiological consequences for this event were reasonable and appropriate. The team concluded that the radiological consequences of this event were negligible, and there were no findings identified in this area.

3.0 MOISTURE SEPARATOR/DRAIN TANK PIPING SYSTEM

3.1 Design, Operation, and Pipe Failure Details

Moisture Separators (MS 'A' and 'B') each receive main steam after it passes through the high pressure main turbine. They remove water from the steam before it reaches the low pressure turbines. The water collects in the respective MS drain tanks. Each drain tank has a control system to regulate level. As drain tank level increases, the normal drain valve opens and allows the water to flow to the feedwater heaters. If level in the drain tank increases further, the respective dump line valve (LV-1039A or LV-1039B) opens and drains the water to the condenser. If level increases still further, a turbine trip is initiated to prevent water from entering the steam line to the low pressure turbines. The operating pressure of each MS is about 160 psig, while the main condenser is maintained at a vacuum.

3.2 Historical Chronology - Design and Operational Details and Challenges

a. Inspection Scope

The team reviewed the design and operation of the MS and drain system to determine how the design and operation may have affected the pipe failure. The team also reviewed the history of design and operational challenges to determine if there were prior opportunities to identify and correct the conditions that led to the event. A chronology of some MS/drain system and level control valve issues is provided in Attachment D.

The team reviewed the fabrication code requirements (ANSI B 31.1, 1973 edition with addenda through winter 1974) to assess compliance with material, welding and nondestructive test requirements applied during the design and fabrication of the MS drain line and the attachment of an encapsulation device at the weld of the system pipe to the condenser nozzle. The team reviewed the stress analysis calculations to assess compliance with the fabrication code requirements, as originally designed and as revised subsequent to the installation of the encapsulation in October 1988.

The team also evaluated PSEG's implementation of the flow accelerated corrosion (FAC) program to determine if the material and operating parameters at the failed location were considered for inclusion in the program; and whether this specific location was in the program for periodic inspection.

The team evaluated PSEG's implementation of 10 CFR 50.65 (Maintenance Rule) as related to the MS drain system (including the level control valve) in order to assess whether ineffective system monitoring contributed to system performance deficiencies.

b. Findings

The MS drain line is non-safety related piping and is not required to be in the in-service inspection program. Consequently, the welds in this line were not periodically inspected. Also, the location of the failure was not in the FAC program because the alloy steel material (1¼% chromium, ½% molybdenum) was not considered susceptible to corrosion/erosion in single or two-phase flow.

Although PSEG determined that the construction materials and operating variables did not meet the criteria for FAC program inclusion, technicians had performed some examination of the piping between LV-1039A and the main condenser. This was done on several prior occasions when LV-1039A experienced valve seat leakage. PSEG examined the locations immediately downstream of this valve (as per FAC program recommendations) using ultrasonic techniques to measure wall thickness. These thickness measurements had been made during outages in 1997, 1999, and 2003. The results of this testing confirmed there was no unidentified or unexpected material corrosion. The wall thickness was verified to be within the acceptance criteria for the specified pipe material size and schedule. The team reviewed these inspection results and confirmed these conclusions.

A vacuum leak in October 1988 apparently resulted from line AC-8"-GAD-032 movement (same line that failed on October 10, 2004), caused by two-phase flow in the line as a result of LV-1039A being failed open (due to a disconnected air line). The vacuum leak developed at the weld where the drain line passed through the condenser penetration, and occurred after two days of operating with valve LV-1039A failed open. With this valve open, the MS drain tank water drained into the condenser, and then allowed steam to enter the line along with the water separated from the steam. The two-phase flow apparently caused excessive line movement, which flexed the line at the point where the line was welded to the main condenser penetration (anchor point). The 8-inch line passes through the 10-inch penetration. The leak occurred on the weld that seals the metal "donut" in the area between the line and the penetration. Since the line did not rupture and the crack was near the condenser, there was no steam leak during the 1988 event. Rather, the leak allowed air intrusion between the line and the penetration into the condenser resulting in a degraded condenser vacuum and elevated offgas system flow. PSEG implemented modification DCR 4-HM-0494 to correct the October 1988 vacuum leak by encapsulating the leak site with a welded encapsulation ring. The modification package documented that the change increased the rigidity of the penetration connection. The change also moved the effective flex point of the line to the point where the encapsulation ring was welded to the pipe.

The October 10, 2004, 'A' MS drain tank line failure resulted in the complete severance of the pipe, approximately 12 - 18 inches from the 'A' condenser shell penetration. The pipe failure occurred in a seamless 8-inch Schedule 40 (0.322 inch wall thickness) of ASTM A335 Grade P11 (1¼% chromium, ½% molybdenum) alloy steel material. The break occurred at the toe of the weld, which had been made during the encapsulation repair of the weld joint that failed in October 1988. The current failure, at the toe of the weld attaching the encapsulating device to the process pipe, was approximately 2½ inches upstream of the 1988 crack. There was evidence of some cavitation damage on the drain pipe inside diameter close to the recent failure but, was not significant. The inside diameter of the pipe did not exhibit a general wall thinning at any location.

The team determined there were prior opportunities to potentially prevent the October 10, 2004, pipe failure. Specifically, the 1988 encapsulation repair did not address the root cause for the pipe crack, which appeared to be related to operating the drain line outside its design. Rather, the encapsulation sealed the vacuum leak but moved the flex point slightly upstream of the repair.

Another missed opportunity was when the encapsulation was installed in 1988. The original scope of the controlling modification discussed a request to engineering to evaluate the need for additional supports on the MS drain line. The associated installation plan recommended vibration monitors on the piping. However, these recommendations were not implemented, and represent missed opportunities to determine whether vibration and line movement were acceptable for the piping configuration and operation.

Vendor Instruction GEK-37949A, "MS and Reheater Drain Systems," stated that the check valve in the normal drain path (to the feedwater heaters) should be located close to the branch point for the dump line to minimize the amount of saturated water upstream of the check valve. The GEK-37949 instruction also stated that two-phase flow anywhere in the lines upstream of the level control valves can produce pressure pulsations and uncontrollable level oscillations in the drain tank; and that it was important that only single-phase liquid exist upstream of the level control valves. The team found that the location of the check valve associated with the 'B' MS drain piping is much closer to its branch point than the 'A' MS system. Further, as can be seen in Attachment D, there were significantly more problems associated with the 'A' vs. the 'B' MS drain system. While PSEG had previously planned a detailed review of this information to determine whether system modifications were necessary, no such review was completed. While not directly related to this event, this was a missed opportunity to improve operation of the 'A' MS drain system.

There were additional historical challenges associated with the MS system. The chronology in Attachment D identifies four prior reactor scrams (2002, 1998, and two in 1990), caused by turbine trips as a result of a high level in the 'A' MS. Although not directly related to the October 10, 2004, event, these problems related to overall response of the MS drain and level control system.

The team determined that PSEG monitored the MS/drain system as required by the Maintenance Rule. The MS/drain system is properly classified as a low risk system and is monitored on the plant level; and the system and affected functions had been monitored as required by (a)(2) of the rule. PSEG evaluated the 1998 and 2002 reactor scrams to be preventable system functional failures. Neither of those scrams, nor the combination of the two scrams, required the system to be placed in goal setting, as required by (a)(1) of the rule. By the end of this inspection, however, PSEG was evaluating the pipe failure event relative to the preventable system functional failure perspective. These results will be considered with existing system performance data, as well as plant level data. The results of this review may potentially require goal setting for the MS/drain system. PSEG is tracking this evaluation and its results as Operation 4160 of Order 70041898.

3.3 Failure to Evaluate and Correct Degraded Condition

a. Inspection Scope

The team reviewed the details associated with the operation of the MS drain tank and level control system. In particular, the team focused on Notifications 20203784 and 20204256, which documented the degraded condition of LV-1039A since September 16, 2004. The team reviewed procedures, PSEG's root cause evaluation, and interviewed personnel in order to evaluate the circumstances and causes that led to the October 10, 2004, MS drain line failure.

b. Findings

Introduction. A self-revealing finding of low to moderate safety significance (Preliminary White) was identified related to PSEG's failure to adequately evaluate and correct a degraded condition since September 16, 2004, as required by station procedures. A preliminary risk analysis determined the finding to be of low to moderate safety significance based on the increased frequency of a transient with the loss of the power conversion system initiating event over the 25-day exposure period.

Description. Notification 20203784 was written on September 16, 2004, which identified that the MS low level alarm was received and the 'A' MS dump valve, LV-1039A, was noted on CRIDS (computer display) to be about 10% open while the associated valve controller was receiving an air signal to fully close the valve. The team concluded that this was the point in time where the valve had been opened for sufficient duration to completely drain the ‘A’ MS drain tank (valve open and MS low level alarm). A condenser area entry was made on September 16 to investigate fittings associated with the air supply line. Engineering and operations personnel discussed this issue, and engineering responded formally on September 20, stating that there was not an immediate safety concern.

However, an operator, not satisfied with the September 20 notification response, initiated another notification (No. 20204256) that same day, stating that the prior notification addressed only flow accelerated corrosion concerns. Specifically, it did not address potential impact to the condenser/baffle plate, and the potential impact to the condenser penetration which had cracked on an earlier occasion (1988) when this same dump valve had failed open for an extended period of time (resulting in elevated offgas flow due to increased in-leakage through the crack at the penetration to the condenser). Again, a formal engineering response, completed on September 22, did not address the entire concern. Only the first issue of potential internal condenser damage was addressed, and the response re-stated the original flow accelerated corrosion response.

The responses to both notifications stated that the affected valve and associated piping would be inspected during the upcoming refueling outage, scheduled to begin around the end of October 2004.

Neither evaluation considered that two-phase flow could be present from the MS drain tank (operating pressure - about 160 psig) to the main condenser (operating pressure - vacuum conditions). The total length of piping from the MS drain tank to the condenser is about 60 linear feet. This piping was not designed for the dynamic loading that would accompany two-phase flow. The disconnected hanger (H25), while likewise unknown at the time, was not available to mitigate the dynamic loading of the lines. The team concluded that engineering’s evaluations associated with the two notifications were inadequate because the associated MWe reduction due to the leakage, the loss of water level in MS ‘A’ and the difference in operating pressures in the MS drain tank and the main condenser, should have led to the recognition that there was two-phase flow in the line upstream of LV-1039A.

After about 25 days (September 16 to October 10, 2004) of operation beyond the design loading capacity of the MS drain tank piping, the 8-inch pipe failed near the condenser penetration, resulting in a steam leak, manual reactor scram, and loss of condenser vacuum.

Analysis. The performance deficiency involved the failure to perform an adequate evaluation to correct the condition or cause of the deficiency as required by PSEG’s Corrective Action Program, NC.WM-AP.ZZ-0002(Q), “Corrective Action Process.” Specifically, PSEG did not identify that the failure of LV-1039A caused two-phase flow in the drain system which resulted in piping fatigue, and represented an increase in the likelihood of a reactor scram with the loss of the condenser heat sink. This deficiency was indicative of cross-cutting weaknesses in the area of problem identification and resolution (evaluation and corrective action).

In addition, Engineering and Technical Support Information Communication Protocol desk top guide, Section 4.4, required that when responding directly to a notification without the use of an order (e.g., a request for follow-up assessment - RFA) peer and supervisory review should be documented in the text provided. PSEG's root cause analysis determined that there was no peer review of the response and the engineer's supervisor reviewed the response, but did not recognize that the response did not address, as requested, the prior failure of this line under the same conditions. PSEG's root cause analysis noted that the engineer's supervisor and multiple engineers were not aware of the written guidelines regarding use of the RFA process.

This issue was more than minor because it is associated with the Equipment Performance attribute of the Initiating Events cornerstone and affected the objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions. In accordance with NRC IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the significance determination process (SDP) Phase 1 required a Phase 2 risk evaluation because the finding contributed to both the likelihood of a reactor trip and the likelihood that the condenser heat sink (power conversion system) would not be available due to a loss of condenser vacuum.

The Region I Senior Reactor Analyst (SRA) estimated the delta (increase) in core damage frequency (ΔCDF) and large early release frequency (ΔLERF) for this finding with a modified Phase 2 risk analysis, using the Risk Informed Inspection Notebook for Hope Creek and IMC 0609 Appendix H, "Containment Integrity Significance Determination Process." The only affected attribute within the notebook was the transient with the loss of the power conversion system (TPCS) initiating event (IE) frequency. As such, the TPCS worksheet (Table 3.2) was modified and used for the evaluation. This was an initiating event finding and therefore the impact of external events was not evaluated.

The ΔCDF estimation used Table 3.2 with the following assumptions and modifications:

- The exposure time was the 25 days that the valve was failed open.

- The frequency of the occurrence of the pipe break was unknown and the TPCS IE frequency was increased by one order of magnitude, from a 1 in 100 chance to a 1 in 10 chance, over the 25 days. (IMC 609 Appendix A, Phase 2 Usage Rule 1.2)

- No condenser recovery credit was given.

- The credit (failure probability) for the high pressure injection (HPI) safety function (HPCI and RCIC) was E-3 (1 failure in 1,000 tries) based on the most recent NRC failure probability information.

The ΔLERF estimation used the ΔCDF core damage sequences and assessed them for a BWR Mark I containment using the following assumptions:

- The early core damage accident sequences were 1TPCS, a low pressure sequence and 4TPCS, a high pressure sequence. The conditional LERF factors with a flood containment of 0.1 for a low pressure sequence and 0.6 for a high pressure sequence were used. PSEG's emergency operating procedures directed the operators to flood the containment using the fire water system prior to reactor vessel breach.

- Accident sequence 2TPCS, a long term accident sequence that involves failure of containment heat removal and ultimately progress to containment failure, was assumed not to contribute to LERF. It is assumed that effective emergency response actions can be taken within the long time frame of this accident sequence.

The risk analysis determined that, given the increased frequency of a TPCS initiating event over the 25-day exposure period, the finding had low to moderate safety significance (White) based on ΔCDF and ΔLERF. The ΔCDF, in the low E-6 per year range (an increased frequency of approximately 1 core damage accident in 600,000 years of reactor operation), was dominated by failures of containment heat removal and containment venting prior to containment failure (sequence 2TPCS). The ΔLERF, in the low E-7 per year range (an increased frequency of approximately 1 large early release in 6,000,000 years of reactor operation), was dominated by two sequences: 1) the failure of containment heat removal, successful depressurization and containment venting, followed by a failure of late injection (sequence 1TPCS); and 2) a failure of high pressure injection systems and failure to depressurize the reactor (sequence 4TPCS). In discussions with the SRA, the PSEG risk analysis staff agreed with this risk characterization based on the modified Phase 2 assessment.

<u>Enforcement</u>. There were no violations of NRC regulatory requirements because the main turbine and extraction steam systems are not safety related. PSEG entered this finding into their corrective action program as Notification 20206626 and Order 70041898. **(FIN 05000354/2004013-04, Failure to Adequately Evaluate and Correct a Failed Open Level Control Valve in the Moisture Separator Drain System)**

4.0 RISK SIGNIFICANCE OF THE OCTOBER 10, 2004 EVENT

The team concluded that the event did not present any actual consequence to the health and safety of the public because operators successfully shutdown the reactor in response to the steam leak. The team conducted an initiating event risk assessment to determine the chance of core damage during the event (conditional core damage probability). This event risk assessment estimated a conditional core damage probability in the low E-5 range (approximately 1 in 60,000) using the NRC's standardized plant analysis risk (SPAR) model for Hope Creek, revision 3.10.

The following assumptions were used:

- The operator actions to manually scram the unit and then shut the MSIVs was best modeled as a plant transient with loss of the condenser heat sink (IE-OCHS);
- Given the pipe break and lowering condenser vacuum, the condenser heat sink was not recoverable; and
- All mitigating systems other than the condenser heat sink and feedwater were available during the event.

The dominant accident sequence involved core damage due to an assumed inability to pump water to the reactor after a containment failure. The containment failure would be caused by the inability to remove decay heat from the containment and failure to lower containment pressure by venting. The sequence involves successful reactor scram and high pressure injection (HPCI or RCIC) and reactor depressurization. PSEG also performed an initiating event assessment for this event and reached a similar, though slightly lower, conclusion relative to the CCDP (approximately 1 in 200,000 similar events). The lower CCDP appeared to be due, at least in part, to an assumption in PSEG's PRA model that, after containment failure, there is a chance that core damage could be prevented by pumping water to the reactor.

5.0 EVENT ROOT CAUSES AND CAUSAL FACTORS

a. Inspection Scope

The inspection team reviewed PSEG's Root Cause Analysis Report for the MS Drain Line Failure (Order 70041898). In addition, the team independently assessed the October 10, 2004, event to determine causal factors and root causes. The team reviewed data and documentation, and conducted personnel interviews.

The team reviewed the methodology used in the laboratory investigation of the failed pipe and the detached MS drain tank pipe hanger (H25), and assessed the results of those tests used to examine the failed parts. Those tests included sectioning of the failed segments followed by visual, macroscopic and microscopic examination, chemical analysis, mechanical testing and metallurgical assessments. The laboratory also conducted an assessment of pipe hanger H25 to determine the possible causes of rod disengagement from its upper eye nut. The team also reviewed the examination activities and the assessments of the condition of the threaded rod, eye nut and corrosion evaluation of the component parts.

b. Findings

During this review, the team assessed and verified that the identified root and contributing causes were appropriate. PSEG's root cause analysis report associated with the MS drain line failure identified two primary root causes. One was inadequate decisions by engineering and management to continue operating the MS system with the drain valve failed open; PSEG did not have a rigorous process to apply effective decision-making principles to management and engineering decisions in response to plant conditions that fall below licensing thresholds and/or are not clearly defined by existing procedures. The second root cause was that operating procedures for the MS level control system were inadequate to prevent extended operation of the system in the condition of unstable two-phase flow.

PSEG also identified several contributing causes as listed below:

- The disconnected hanger (H25) was not discovered by any type of inspection, thereby allowing it to fret through the instrument tray and tubing causing LV-1039A to fail open;

- The condition of LV-1039A was not monitored to detect further degradation; and

- Appropriate rigor was not applied to the engineering evaluation of the abnormal condition. Operators raised a concern about the prior pipe failure caused by operating with LV-1039A open. Engineering did not research that failure and did not address it in the response.

PSEG sent the failed pipe section and disconnected hanger (H25) for detailed laboratory failure analysis to supplement their root cause investigation. The results of the failure analyses are as follows.

- The primary crack in the 8-inch pipe was initiated by high cycle fatigue due to system vibration. The crack propagated around the majority of the 8-inch pipe circumference at or near the toe of the fillet weld by fatigue crack growth combined with ductile tearing.

- There were no material or fabrication process deficiencies that contributed to the pipe failure.

- Evidence suggested that the 1988 failure mode was fatigue. The existence of the crack beneath the encapsulation resulted in a higher stress concentration on the encapsulation to 8-inch pipe joint at the 2004 fracture location.

Laboratory observations regarding the Hanger H25 components were as follows:

- The upper threaded rod was engaged into the eye nut approximately ½ inch.

- Although the jam nut may have been in contact with the eye nut at one time, it was found out of place at the bottom of the threads for a long period of time.

The team reviewed PSEG's root cause analysis report and concluded that the evaluation was comprehensive and appropriately considered potential causes and extent of condition for the steam pipe failure, including the problems encountered during the event. The team determined that PSEG properly identified the causal factors and root causes for the event. The team also evaluated the results of failure analysis performed on the failed components, as well as PSEG's assessment of those results, and concluded the identification of the failure mechanism as high cycle fatigue induced by system vibration (due to the two-phase flow) was reasonable.

6.0 EXTENT OF CONDITION AND CORRECTIVE ACTIONS

6.1 Extent of Condition Review

a. Inspection Scope

The team reviewed PSEG's evaluation to determine whether they appropriately considered and assessed the extent of condition. In particular, the team focused on PSEG's review and inspection/examination of similar balance-of-plant (BOP) systems and components with similar operating characteristics (including normal and off normal conditions) to ensure they were evaluated for similar degradation. The team also reviewed PSEG's extent of condition assessment related to non-safety related BOP pipe hangers and supports, which had not been subject to a formal periodic inspection and examination.

The team reviewed PSEG's criteria used to include systems and components for examination as part of the extent of condition effort. The team reviewed the examination methods (visual, magnetic particle and ultrasonic test), qualification of examiners, acceptance criteria, and test results. In addition, team members performed a walk-down of selected portions of the failed system and other BOP piping in locations where similar piping penetrates the condenser. The team reviewed examination results of all piping and nozzles inspected internal and external to the condenser.

b. Findings

PSEG's extent of condition evaluations considered both Hope Creek and Salem plants.

Piping

The selection of locations to be non-destructively examined was made to include all piping that is connected to main condenser nozzles that have a potential for nozzle and/or piping damage as a result of two-phase flow. This included piping to the condenser associated with valves that leaked in the past. PSEG reviewed notifications and work orders that included the following systems: main steam, condenser/feedwater, extraction steam, and heater drains. As a result of this review, 14 additional condenser penetrations were identified for inspection. The sample plan also included visual and magnetic particle examination on all welds on the 'A' and 'B' MS drain lines.

Because the October 10, 2004, pipe failure occurred at the location of a pipe attachment intended to contain a leak (1988 weld failure - encapsulation), PSEG performed a search to identify any other encapsulation devices that may have been used to contain leaks in BOP systems. The team noted that as a result of this examination effort, an additional encapsulation was identified on the steam seal evaporator relief valve piping.

No indications were identified in the vicinity of this encapsulation, or at any other location in the inspection sample. These lines were examined inside and outside the condenser.

During these inspections and examinations, some indications were identified, for which PSEG removed/repaired them as necessary. Defects were removed by grinding as necessary, and were verified as eliminated with the appropriate nondestructive examination technique before repair activities were completed. Repairs were made to within the original design specification requirements, and the weld repair locations were non-destructively tested to verify weld soundness.

Pipe Hangers

PSEG formulated a plan to select and evaluate pipe hangers and supports in a large sample of BOP steam and high-energy water systems at Hope Creek and Salem. The selection was based on those systems with similar design, materials, operating parameters, and were believed to potentially have been exposed to two-phase flow (but designed for single phase flow). Also, systems were selected which similarly had a known history of valve leakage, either periodically or continuously, where such operation would be outside the piping design and potentially result in the application of unanalyzed forces (static or cyclic) to system components. PSEG performed system and component corrective action document searches, reviewed industry operating experience, and conducted interviews to aid in selecting the inspection sample.

Field inspections encompassed validation of integrity of over 5000 hangers in Hope Creek and Salem. Of this sample, 206 deficiencies were identified. Deficiencies were identified in the following broad categories; bent rod or support, bottomed-out spring can, loose support components, signs of excess vibration, or loose jam nuts on pipe hangers. The majority of the deficiencies were screened as having negligible impact because the discrepancies were minor and would not affect the function of the support. These deficiencies were entered into the corrective action process. Of the 206 deficiencies identified, less than ten were considered more than minor and none were evaluated as having an immediate impact on structural integrity of the associated system.

The team found the extent of condition reviews to be acceptable both in scope and detail. The original scope of the reviews were appropriately expanded as new information became available. The team also reviewed the types of problems found during the hanger walkdowns; none of the problems appeared to adversely affect the piping or associated systems.

6.2 Corrective Actions

a. Inspection Scope

The team reviewed the immediate and longer term corrective actions that PSEG proposed to address the deficiencies identified with this event. The team evaluated the corrective actions for appropriateness and effectiveness in correcting the causes. The team also reviewed the priority and schedule associated with the corrective actions to ensure that items requiring resolution prior to plant startup were addressed. In addition, the team reviewed a sample of the corrective actions that had been completed by the end of this inspection.

b. Findings

The team determined that PSEG's proposed corrective actions were appropriate. The team verified that the proposed corrective actions were properly aligned with the identified root and contributing causes. Specifically, the team determined that the proposed corrective actions appeared appropriate to address the event causes.

The corrective actions, some of which are described below, are listed according to the various aspects of the event (engineering issues, pipe failure, disconnected pipe hanger, equipment issues, and operator and training issues). The primary PSEG corrective actions included:

Engineering Issues

- Established a formal process for Operational and Technical Decision Making (OTDM) to apply effective decision-making principles to management and technical decisions; and conduct training on the OTDM Process.

- Any open Hope Creek operability determinations that may be open at restart were evaluated. All open Salem operability determinations will be re-evaluated.

- A review of degraded equipment at Hope Creek and Salem was performed, selected items were re-assessed using the new OTDM Process.

- Improve system engineer walkdowns by developing system specific walkdown plans and providing training on degradation mechanisms.

- Developed and implemented an Adverse Condition Monitoring procedure, to be used in conjunction with the OTDM procedure.

- Director of Engineering to review the success of the actions taken to improve engineering rigor and set expectations for review and documentation of engineering replies to requests from various sources.

Pipe Failure

- Repaired the failed nozzle and minimize stress intensification factors.

- Revised plant operating procedures (and train operators) for the MS drain piping to prohibit extended operation with the LV-1039A or LV-1039B valve open coincident with loss of level in the MS drain tank. This action prevents operating the drain lines with two-phase flow (outside their design).

- Remove the encapsulation found on the steam seal evaporator relief valve and repair the existing defect.

- An evaluation will be performed to consider relocating the check valve in the 'A' MS drain piping (in the normal MS drain path - to the feedwater heaters) closer to the MS drain tank, as per vendor guidance. Since the pipe failure was not caused by the check valve configuration, this action does not have a direct impact on the event causes. The team noted, however, that this effort may improve the response of the 'A' MS drain tank level during transient conditions.

- Dynamic modeling of the system will be performed to evaluate the loads during normal system operation. Since the failure was not caused by normal operation of the system, this action does not have a direct impact on the event causes. However, the team noted that improved understanding of the response of the 'A' MS drain tank level during transients may provide useful operating insights.

- The feedwater heater operating procedures were revised to limit extended operation with leaking dump valves or inadequate feedwater heater level control.

<u>Disconnected Pipe Hanger</u>

- Reinstalled H25 (replacing damaged components) in accordance with the manufacturer installation recommendations; and repaired the instrument tubing that was damaged by the disconnected H25 hanger.

- Addressed the pipe hanger discrepancies identified during the extent of condition inspections. Also, about 30 Hope Creek pipe hangers were identified with jam nut discrepancies. As found hanger rod thread engagement were checked when the hangers were repaired.

- Establish a formal inspection program for pipe hangers in non-safety related systems at Hope Creek and Salem. Formal inspection programs already existed for safety related hangers.

<u>Equipment Issues</u>

- Replaced HPCI vacuum pump/motor and grease the pump using the proper lubricant. Determined extent of condition associated with RCIC system.

- Changed the site computer lubrication screens for HPCI/RCIC vacuum pumps; and evaluated the extent of condition of lubrication screen errors.

- Adjusted the limit switches for valve HV-8278. Evaluated additional completed motor-operated valve diagnostic testing to confirm proper limit switch setting. Enhanced procedures to provide clear acceptance criteria regarding limit switch setting; and revised engineering procedures related to reviewing limit switch settings to ensure data is effectively and properly reviewed.

Operator and Training Issues

- Revised HPCI/RCIC procedures to warn operators of potential flow instability. Trained operators on this phenomenon and the revised procedures. Revised the simulator to model the flow instability phenomenon for HPCI/RCIC.

- Provided operator training regarding TS usage with focus on the performance deficiencies where operators misinterpreted TSs.

- Revised procedures to address operator challenges regarding reactor vessel level control (e.g., provide guidance to allow changing level bands when controlling pressure with SRVs)

- Implemented simulator upgrade (which was being developed prior to the October 10, 2004, event), which provides improved modeling of balance of plant systems.

The team reviewed PSEG's proposed corrective actions; and reviewed a sample of the completed corrective actions, including the OTDM procedure, selected procedure revisions, and training corrective actions. The team determined that PSEG's corrective actions were appropriate to address the identified problems, and confirmed that corrective actions necessary for plant restart were scheduled to be completed prior to restart.

7.0 GENERIC ISSUES

During this inspection, no significant issues were identified requiring the issuance of generic communications to the nuclear industry.

8.0 CROSS-CUTTING ASPECTS OF FINDINGS

Section 2.2.1 describes a finding that involved inadequate human performance (personnel) as a primary cause. The finding also had a problem identification and resolution (identification) cross-cutting aspect where engineering review of data did not identify this performance deficiency.

Section 2.2.2 describes a finding where procedures for operating the RCIC system were inadequate, and involved problem identification and resolution (identification) as an underlying cause. The finding also involved a human performance (organization) cross-cutting aspect where operating and vendor experience were not incorporated into procedures and training.

Section 2.2.3 describes a finding regarding maintenance that involved human performance (organization) as an underlying causal factor. The finding also involved a problem identification and resolution (corrective action) cross-cutting aspect since there was a prior opportunity to correct degraded performance.

Section 3.3 describes a finding where engineering staff did not properly evaluate and correct a degraded level control valve for the ‘A’ MS drain tank, and was indicative of a cross-cutting weakness in the area of problem identification and resolution (evaluation and corrective action).

9.0 EXIT MEETING SUMMARY

The NRC presented the results of this special inspection to Mr. A. Christopher Bakken, III, and other members of PSEG management on January 12, 2005. Hope Creek management acknowledged the findings presented. No proprietary information was identified.

ATTACHMENT A

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel:

C. Bauer, Operations Superintendent
M. Bergman, System Engineer
R. Braddick, Operations Superintendent
W. Brammeier, ISI/IST Inspector
J. Clancy, Manager, Technical Support, Radiation Protection and Chemistry
M. Conroy, Senior Engineer, Engineering Programs
A. Garcia, Senior Engineer, Engineering Programs
J. Hutton, Hope Creek Plant Manager
A. Johnson, Supervisor, Civil Design Engineering
L. Koberlein, Nuclear Shift Supervisor
P. Lindsay, Engineering Supervisor, Design Engineering
T. Macewen, Nuclear Shift Supervisor
R. Montgomery, Senior Engineer (FAC Program)
J. Morrison, Engineering Supervisor
L. Rajkowski, Manager, Hope Creek System Engineering
T. Roberts, Supervisor, Engineering Programs
B. Sebastian, Technical Superintendent, Hope Creek Radiation Protection
G. Sosson, Hope Creek Operations Manager
H. Swartz, Simulator Support Group Supervisor
B. Thomas, Senior Licensing Engineer
W. Treston, ISI/IST Supervisor
R. Villar, Senior Licensing Engineer
J. Williams, Manager, Hope Creek System Engineering

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000354/2004013-04	FIN	Failure to Adequately Evaluate and Correct a Failed Open Level Control Valve in the Moisture Separator Drain System (Section 3.3)

Opened and Closed

05000354/2004013-01	NCV	Failure to Properly Set Limit and Torque Switches on HPCI Valve in Accordance with Procedures (Section 2.2.1)

05000354/2004013-02	NCV	Failure to Incorporate Operating Experience for Low Flow Operations of RCIC Into Operating Procedures and Operator Training (Section 2.2.2)
05000354/2004013-03	FIN	Failure to Effectively Implement Preventive Maintenance for the HPCI Barometric Condenser Vacuum Pump (Section 2.2.3)

LIST OF DOCUMENTS REVIEWED

Procedures

HC.OP-AB.CONT-0002(Q)	Primary Containment, Rev. 2
HC.OP-AP.ZZ-0000(Q)	Reactor Scram, Rev. 3
HC.OP-AR.ZZ-0014(Q)	Overhead Annunciator Window Box D3, Rev. 17
HC.OP-DG.ZZ-0101	Hope Creek Post-Trip Data Collection Guidelines, Rev. 6
HC.OP-EO.ZZ-0101(Q)	Reactor Pressure Vessel Control, Rev. 10
HC.OP-EO.ZZ-0102(Q)	Containment Control, Rev. 11
HC.OP-FT.AC-0005(Q)	Turbine Overspeed Protection System Operability Test, Rev. 4
HC.OP-SO.AF-0001(Z)	Extraction Steam, Heater Vents and Drains System Operation, Rev. 23
HC.OP-SO.BD-0001(Q)	RCIC System Operation, Rev. 27
HC.OP-SO.BJ-0001(Q)	HPCI System Operation, Rev. 26
HC.OP-SO.SM-0001(Q)	Isolation Systems Operation, Rev. 13
NC.CA-DG.ZZ-0102	Operational and Technical Decision Making Process Desk Guide, Rev. 0
NC.ER-DG.ZZ-0011(Z)	System Walkdown Guideline, Rev. 1
NC.WM-AP.ZZ-0002(Q)	Corrective Action Process, Rev. 8
SE.MR.HC.01	Maintenance Rule System Function and Risk Significance Guide, Rev. 10
SH.OP-AP.ZZ-0108(Q)	Operability Assessment and Equipment Control Program, Rev. 15
SH-MD-EU-ZZ-0011(Q)	VOTES Data Acquisition for Motor Operated Valves, Rev. 8

Drawings

—01-1	Main Steam, Rev. 0
—02-1	Extraction Steam, Rev. 24
—03-1	Vents and Drains Heaters 1 and 2, Rev. 19
—04-1	Vents and Drains Heaters 3, 4, 5 and 6, Rev. 19
1-P-AC-02	System Isometric/Turbine Bldg. MS ‘A’ Drain to Feedwater Heater 5A, 5B & 5C and Condenser A, Rev. 17
1-P-AF-05	System Isometric/Turbine Bldg. Feedwater Heater Drains, Heaters 3A, 3B, 3C, 4A, 4B, 4C & 5A, 5B, 5C, Rev. 14
1-P-AF-06	System Isometric/Turbine Bldg. Feedwater Heater Dumps Heaters 3A, B & C, Rev. 18
1-P-CA-05	System Isometric/Steam Seal Evaporator Relief Valve Piping, Rev. 14

10855-P-0500 Piping Class Sheet - Class GAD, Rev. 5
PM4-0037(01) Turbine Condenser Connection Listings (General Arrangement), Rev. 6
PM4-0037(02) Turbine Condenser Connection Listings, Rev. 20
PM4-0037(03) Turbine Condenser Connection Listings (Encapsulation Detail), Rev. 5
PSEG Control Valve Data Sheet (1ACLV-1039A and 1ACLV-1039B), Rev. 0

Calculations

4M-Z-02503	Change to Stress Calc C-1063 Steam Seal Evaporator Relief Valve Line
C-1045	Turbine Building MS ‘A’ Drain to Feedwater Heater 5A, 5B and 5C - Pipe Stress Calculation, Rev. 12
H-1-ZZ-MDC-1932	Moisture Separator Drain Downstream of 1039A, RFO 11, FAC Exam
H-1-ZZ-MDC-1792	Moisture Separator Drain Downstream of 1039A, RFO 8, FAC Exam
H-1-ZZ-MDC-1754	Moisture Separator Drain Downstream of 1039A, RFO 7, FAC Exam
SC-0263 R0	Moisture Separator Drain (Pipe) of 1039A, RFO 11, FAC Exam

Modifications (Design Change Packages - DCP)

4HM-0494	Encapsulate Vacuum Leak at Condenser “A,” Penetration #56, Rev. 0
4M-Z-02503	Addition of Encapsulation on Condenser Nozzle #29
80051144	Install Quick Exhaust Valves on MS Dump Valves, Rev. 0 and Rev. 1
80075423	Restore HC Main Condenser Nozzle 56 to Original Design, Rev. 0

Work Orders

30087552	60025008	60048663
30087588	60029413	60048697
30087640	60048662	70020654

Notifications

20080033	20206631	20206821	20206946
20081426	20206632	20206848	20206978
20084783	20206633	20206849	20207019
20103635	20206634	20206851	20207038
20140081	20206635	20206880	20207049
20180818	20206665	20206885	20207055
20186175	20206668	20206888	20207067
20203784	20206669	20206889	20207288
20204256	20206766	20206908	20207691
20206604	20206772	20206921	20211633
20206606	20206783	20206926	20212885
20206626	20206801	20206931	20214655
20206627	20206806	20206943	20214768

Examination Test Reports

20206851	RFO12	UT Thickness Examination Record, 1039B downstream area
20206851	RFO12	MT Exam of Encapsulation and two upstream welds to valve 1039B
50045145	RFO11	UT Thickness Examination Record, 1-AC-032-S12-V1
60048662	RFO12	MT Exam of FW 56P, 65
60048697	RFO12	Surface Examination Record of HC-1-AF-135-FW9-R1
60048698	RFO12	MT Exam of nozzle weld downstream of 1505C
60048699	RFO12	MT Exam of nozzle weld downstream of 1531B
60048700	RFO12	MT Exam of nozzle weld downstream of 1531C
60048725	RFO12	MT Exam of nozzle weld downstream of 1521C
60048726	RFO12	MT Exam of nozzle weld downstream of 1521A
60048727	RFO12	MT Exam of nozzle weld downstream of 1521B
60048728	RFO12	MT Exam of nozzle weld downstream of 1513A
60048729	RFO12	MT Exam of nozzle weld downstream of 1513B
60048730	RFO12	MT Exam of nozzle weld downstream of 1513C
60048731	RFO12	MT Exam of nozzle weld downstream of 1505A
60048732	RFO12	MT Exam of nozzle weld downstream of 1505B
60048744	RFO12	MT Exam of nozzle weld downstream of 1994E
980501020	RFO7	UT Thickness Examination Record, 1-AC-032-S12-V1
991109003	RFO8	UT Thickness Examination Record, 1-AC-032-S12-V1

Miscellaneous

Root Cause Analysis Report, Hope Creek Moisture Separator Drain Line Failure (70041898)
Root Cause Investigation Report, Technical Specification and LCO Management (70041900)
Root Cause Investigation Report, Reactor Vessel Water Level Control Difficulties (70041930)

GEK 37949A	MS/Reheater Drain Systems, GE Industrial/Power Systems, Rev. A, June 1977
OE17818	Operating Experience (Steam Leak on Drain to Condenser)

Gaseous Radioactive Waste Release Permits: 200788.017.063.G and 200784.017.060.G
Radiation Protection Shift Log, October 10 & 11, 2004

Station Operation Review Minutes, Meeting No. H2004-023, October 15, 2004

System Health Report, HPCI Sytem, 3rd Quarter, 2004
System Health Report, RCIC Sytem, 3rd Quarter, 2004
System Health Report, Main Turbine and Auxiliary Systems, 3rd Quarter, 2004

Licensee Event Report 50-354/90-001-00
Licensee Event Report 50-354/90-028-01
Licensee Event Report 50-354/98-008-00
Licensee Event Report 50-354/02-004-00

NOH0100ELERS-00 Nuclear Training Center Lesson Plan, Operating Experience, 7/1/02
NOH051004TSJ-00 Nuclear Training Center Lesson Plan, Just-in-Time Training, 11/24/04
SG-600, Simulator Scenario Guide, 10/10/04 Steam Leak Demonstration, 12/8/04

LIST OF ACRONYMS

ANSI	American National Standards Institute
ASTM	American Society for Testing and Materials
BOP	Balance of Plant
BWR	Boiling Water Reactor
CCDP	Conditional Core Damage Probability
CDF	Core Damage Frequency
CIV	Combined Intermediate Valve
CRD	Control Rod Drive
CRIDS	Control Room Indication Display System
CRS	Control Room Supervisor
CST	Condensate Storage Tank
ΔCDF	Delta Core Damage Frequency
ΔLERF	Delta Large Early Release Frequency
ECG	Emergency Classification Guide
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
FAC	Flow Accelerated Corrosion
FIN	Finding
GPM	Gallons per Minute
HPCI	High Pressure Coolant Injection
IE	Initiating Event
ISI/IST	In-service Testing/In-service Inspection
IMC	Inspection Manual Chapter
LCO	Limiting Condition of Operation
LER	Licensee Event Report
LERF	Large Early Release Frequency
LPCI	Low Pressure Injection System
MR	Maintenance Rule
MS	Moisture Separator
MSIV	Main Steam Isolation Valve
MT	Magnetic Particle Test
MWe	MegaWatt - Electric
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
OE	Operating Experience
OTDM	Operational and Technical Decision Making
PRA	Probabilistic Risk Assessment
PSEG	Public Service Enterprise Group
RCIC	Reactor Core Isolation Cooling

RFA	Request for Follow-up Assessment
RFO	Refueling Outage
RFP	Reactor Feed Pump
RG	Regulatory Guide
RHR	Residual Heat Removal
RPS	Reactor Protection System
RWCU	Reactor Water Cleanup
SDP	Significance Determination Process
SJAE	Steam Jet Air Ejector
SM	Shift Manager
SPAR	Standardized Plant Analysis Risk
SPDS	Safety Parameter Display System
SRA	Senior Reactor Analyst
SRO	Senior Reactor Operator
SRV	Safety Relief Valve
TPCS	Transient - Power Conversion System
TS	Technical Specification
TSAS	Technical Specification Action Statement
UT	Ultrasonic Test
VOTES	Valve Operation Test and Evaluation System
UE	Unusual Event
UFSAR	Updated Final Safety Analysis Report

ATTACHMENT B

SPECIAL INSPECTION TEAM CHARTER

October 13, 2004

MEMORANDUM TO:	Raymond K. Lorson, Manager Special Team Inspection Stephen M. Pindale, Leader Special Team Inspection
FROM:	Wayne D. Lanning, Director **/RA/** Division of Reactor Safety
SUBJECT:	SPECIAL TEAM INSPECTION CHARTER - HOPE CREEK NUCLEAR GENERATING STATION

A special inspection has been established to inspect and assess an event that occurred on October 10, 2004, at the Hope Creek Nuclear Generating Station. At 6:14 p.m., the plant was manually scrammed due to the failure of an 8-inch moisture separator drain line. Following the shutdown, there were a number of equipment and operator performance issues. The special inspection will commence on October 14, 2004, and will include:

Manager:	Raymond K. Lorson, Chief, Performance Evaluation Branch
Leader:	Stephen M. Pindale, Senior Reactor Inspector
Full Time Members:	Steven Dennis, Senior Reactor Engineer Thomas F. Burns, Reactor Inspector Joel S. Wiebe, Reactor Inspector Edward C. Knutson, Resident Inspector
Part Time Members:	Nancy T. McNamara, EP Specialist Wayne L. Schmidt, Senior Reactor Analyst Robert Davis, Materials Engineer, NRR

This special team inspection was initiated in accordance with NRC Management Directive 8.3, “NRC Incident Investigation Program.” The decision to perform this special team inspection was based on deterministic criteria in Management Directive 8.3 and the initial risk assessment. Specifically, the condition involved possible adverse generic implications, and involved questions or concerns pertaining to licensee operational performance. The initial risk assessment characterized the conditional core damage probability to be approximately 1 in 200,000, which is in the range for a special inspection.

The inspection will be performed in accordance with the guidance of NRC Inspection Procedure 93812, “Special Inspection,” and the inspection report will be issued within 45 days following the exit meeting for the inspection. If you have any questions regarding the objectives of the attached charter, please contact Ray K. Lorson at 610-337-5282.

Attachment: Special Inspection Charter

Distribution:
E. Cobey, DRP
M. Gray, DRP
S. Barber, DRP
W. Schmidt, DRS
W. Lanning, DRS
R. Crlenjak, DRS
R. Blough, DRP
B. Holian, DRP
D. Collins, PM, NRR
D. Screnci, ORA

Special Inspection Charter

Hope Creek Nuclear Generating Station

Steam Leak Due to a Rupture of the Hope Creek “A” Moisture Separator (MS) Drain Line

Preliminary information regarding the event: On October 10, 2004, at approximately 6:00 p.m., operators lowered reactor power in response to an offgas flow increase and a turbine building ventilation exhaust radiation monitor alarm due to a reported steam leak in the turbine building. At 6:14 p.m., because offgas flow continued to increase and steam was noted in other areas of the turbine building, operators initiated a manual reactor scram to isolate the steam leak, and began a cool down and depressurization to stabilize plant conditions. At 6:22 p.m., in anticipation of a loss of normal heat sink due to slowly degrading main condenser vacuum, operators placed the reactor core isolation cooling (RCIC) and high pressure coolant injection (HPCI) systems in operation for reactor level and pressure control. At 6:28 p.m., operators closed all of the main steam isolation valves (MSIVs) prior to their automatic closure on low condenser vacuum. During the cooldown, reactor water level cycled high and low repeatedly in response to various plant conditions including operator’s initiation of RCIC and HPCI, closure of MSIVs, and opening safety relief valves for pressure control. The cooldown and depressurization continued and operators stabilized the plant in Hot Shutdown at 10:11 p.m. on October 10. The plant was placed in cold shutdown at 5:09 a.m., on October 12.

The source of the steam leak was a rupture of the 8-inch “A” MS drain line to the main condenser. This rupture also caused a decrease in condenser vacuum which complicated post trip reactor water level and pressure control. There were no injuries associated with this event. There was a minor radiation release from the plant that was below federally approved operating limits. The release was monitored by the turbine building exhaust and south plant ventilation stack radiation monitors.

Objectives of the Special Inspection: The objectives of the special inspection are to evaluate the circumstances associated with the event described above. Specifically the inspection should accomplish the following.

a. Develop a detailed event chronology, including key transition (e.g., MSIV closure, RCIC & HPCI initiation, Mode changes, etc.) and operator decision points.

b. Independently evaluate the equipment and human performance issues that complicated the response to this event to assess the adequacy of Hope Creek’s investigation and root cause evaluation with respect to the identification of performance deficiencies, extent of condition review, assessment of potential common mode failures, root cause(s), and corrective actions.

   - Assess operator control of the plant during the event including abnormal and emergency operating procedure usage, the bases for decisions made, and actions taken. Evaluate the causes for, and the significance of, various level changes that occurred during the event.

- Assess whether Hope Creek's investigation appropriately considered operator training issues and effectiveness.
- Assess the adequacy of Hope Creek's plans for corrective actions for the equipment and human performance issues.

c. Evaluate the adequacy of Hope Creek's analysis of the cause(s) for the steam system piping failure, extent of condition and actions to prevent recurrence.

d. Verify that radiological releases were monitored and did not exceed regulatory requirements.

e. Determine whether prior opportunities were available to identify and correct the conditions that led to the steam pipe failure.

f. Review operator compliance with Technical Specifications, Emergency Action Levels, and the Emergency Plan.

g. Independently determine the risk significance of the event.

h. Document the inspection findings and conclusions in a special inspection report in accordance with Inspection Procedure 93812 within 45 days of the exit meeting for the inspection.

ATTACHMENT C

SEQUENCE OF EVENTS

Entries that appear in *italics* are notes or observations made by the NRC inspection team. All other entries were obtained from various licensee sources, and the specific sources are noted in parentheses, ( ). Refer to the end of this attachment for the source codes.

Initial Plant Conditions (Pre-Event) - 100% Reactor Power

Time	Event
[October 10, 2004]	
17:39	Received annunciator "Offgas Recombiner Panel 00C327" in the control room. *This was the operator's first indication of the developing steam leak from the A moisture separator (MS) drain line.* (1)
17:41	Turbine Building Exhaust Radiation Monitor in alarm at "Alert" level and rising. *This was due to steam in the turbine building.* (1)
17:50	Operator in the plant reports that steam is evident on the 137' turbine building elevation (turbine deck) in the vicinity of the front standard of the main turbine. (1)
17:51	Radwaste operator investigating the offgas recombiner panel alarm at 17:39 reports that the alarm is due to elevated offgas flow at 63 cfm *(normal offgas flow is about 25 cfm)* and rising. 'B' steam jet air ejector backpressure is 5 psig and rising. (1)
17:53	Received annunciator "Fire Protection Panel 10C671" associated with room 1704/1705 (elevation 171' turbine building). *This was also due to steam in the turbine building.* (1)
17:59	Operators commenced power reduction with recirc flow. (1)
	Offgas flow greater than 115 cfm, 'B' steam jet air ejector backpressure is pegged high. (1)
	Main condenser vacuum has yet to be significantly affected and remains steady at 3.2" Hg. (1), (2)
18:04	Power has been reduced to just under 80 percent with recirc flow, main condenser vacuum has improved to 2.6" Hg due to the power reduction. (1)

18:05 Operator in the plant observes that steam leakage from a previously existing leak on the '6A' feedwater heater extraction steam line appears to have gotten worse. *Operators initially believed this was the source of the current steam leak in the turbine building.* (1)

18:06 Operators closed the '6A' feedwater heater extraction steam isolation valve in an attempt to isolate the steam leak. (1)

18:10 Operator in the plant reports that steam leakage in the turbine building is continuing to worsen. (1)

Operators resumed power reduction with recirc flow. (1)

18:12:35 Based on the inability to isolate the steam leak and worsening conditions in the turbine building, the control room supervisor directs a manual reactor scram. Operators insert the scram *(from about 69% power)* by placing the reactor mode switch in "Shutdown."

18:12:40 Received reactor low water level scram due to level shrink following the scram (*expected condition*). (4)

18:12:45 Operators secured the 'B' reactor feedwater pump (*expected operator action to secure one of the operating reactor feedwater pumps following a scram to prevent overfeeding the reactor vessel. 'A' and 'C' feedwater pumps remain in service*). (4)

18:12:57 Received scram discharge volume level high scram alarm (*expected condition*). (4)

18:13:15 Reactor vessel water level reaches a post-scram transient low point of -14 inches. (6)

18:13:30 Operators trip the main turbine (*expected operator action following a scram*), received turbine stop and control valve scrams (*expected condition*). (4)

Using the rod worth minimizer and SPDS, operators verified that all control rods are fully inserted. (1), (3)

18:15 Condenser backpressure beginning to rise, indicates 6" Hg. Operators initiate reactor pressure reduction to less than 700 psig using the bypass valves, to be within the capability of the secondary condensate pumps, and to reduce the driving force on the steam leak. (1), (3)

18:16 The operating RWCU system pump ('B') trips. Operators attribute this to the rapid reactor pressure reduction *(an expected possibility based on plant operating experience, but not due to a system design function).* (1), (3) *Note that, as a result, the RWCU system is no longer available for vessel inventory reduction. Although this capability is desirable, its loss did not result in any significant operational consequences during the remainder of the event.*

18:17:12 ‘A’ and ‘C’ reactor feedwater pumps trip automatically due to low condenser vacuum (turbine driven pumps), reactor pressure is 705 psig (still beyond the capability of the secondary condensate pumps). (1), (4)

Note that CRD (a relatively low volume source) is the only input to reactor vessel water inventory.

18:17:43 Bypass valves peak open at about 47 percent. (6)

18:17:55 Reactor vessel water level has risen *(due to swell caused by the bypass valves opening)* to a high point of 30 inches. (6)

18:18 Based on rates of pressure and level change, the shift technical advisor determined that there will not be enough vessel water inventory to depressurize to within the capability of the secondary condensate pumps before reaching Level 2 (-38 inches). The control room supervisor directed closing the bypass valves to maintain inventory (four bypass valves are currently open), and directed startup of HPCI and RCIC. (1), (3)

Note that bypass valve closure is not instantaneous, but rather occurs sequentially.

Reactor vessel water level begins to drop rapidly due to shrink from closing the bypass valves and inventory depletion. (6)

18:19:14 Operators initiate RCIC using the manual initiation switch. This initiates the system startup sequence (*the pump is not yet injecting*). (4)

18:19:27 Reactor vessel water level reaches a transient low point of -38 inches (Level 2). (6)

The level 2 condition was caused by low initial vessel water inventory, loss of the reactor feedwater pumps, continuing inventory use while the bypass valves were closing, and level shrink due to closure of the bypass valves. (1)

18:19:39 RCIC injection peaks at about 650 gpm, then stabilizes at about 600 gpm. (6)

HPCI injection peaks at about 6000 gpm. Operators take action to secure HPCI flow to the reactor, to prevent vessel overfill (since the Level 2 condition was, in part, due to shrink, level would recover to some extent on its own following the transient; and, RCIC was already providing adequate makeup). (6), (10)

18:19:43 All bypass valves are closed *(they were sequentially closing since 18:18).* (4)

18:19:50 Water level has risen to -20 inches and then begins to recover more slowly. (6)

18:20:12 HPCI injection flow to reactor vessel secured *(system in idle mode - minimum recirculation flow)*. (6)

18:20 - 18:30 Operators are switching HPCI to pressure control mode. *In this mode of operation, the HPCI pump recirculates water to the condensate storage tank (no injection to the reactor vessel) and the amount of flow determines the amount of steam that is drawn from the reactor to power the pump. This provides greater control of steam demand than use of the SRVs, and reduces the energy content of the steam being discharged to the torus*. (1), (3)

When operators attempted to reposition the HPCI full flow test line control valve (F008), the valve did not open. *The valve is interlocked with two other system valves in the injection flow path, to prevent inadvertent diversion of flow from the reactor*. After the two other valves were given an additional closed signal (they were already closed), operators were able to open F008.

18:22:34 Recognizing that MSIV closure due to degrading main condenser vacuum was imminent, operators start to reopen the bypass valves (*to reject as much energy to the main condenser as possible*). (4), (10)

18:24:35 Bypass valves peak at about 14 percent, then begin to close. (6)

18:25:10 Main condenser vacuum has dropped to 20" Hg, operators closed the inboard and outboard MSIVs. (1), (4)

18:27 Operators placed the RHR system in torus cooling mode using ‘A’ and ‘B’ RHR pumps. (1), (4)

18:30:23 Operators commence operation of HPCI in pressure control mode, recirculation flow to the CST is increasing slowly. (6)

18:32:07 Reactor vessel water level is now 12.5 inches (Level 3) by wide range indication and increasing. (6)

18:33:41 Operators decrease RCIC flow to stabilize reactor vessel water level. (6)

18:35:06 At about 350 gpm, RCIC flow begins to oscillate (dropping to nearly zero and then recovering). This was due to system instability when using the automatic flow controller at low flow. *This condition is known to the vendor, who recommends use of the manual flow controller at low flow conditions, but was not known to the operators, nor was it discussed in the system operating procedure*. As a result, operators continued to operate the system in automatic, and believed that there may be a problem with the RCIC system. (6)

18:36:45 Operators secured RCIC injection. (6)

18:38 Reactor vessel water level stable at about 30 inches. (6)

18:41 Water level begins to lower slowly. (6)

18:43 HPCI recirculation flow to the CST has slowly been increased to 5500 gpm and is now stable. (6)

18:45 Operators commence RCIC injection, with flow oscillations occurring at low flow (five oscillations over the next three minutes). (6)

18:45:29 Operators consider that plant conditions have adequately stabilized and reset the scram. (4)

Note that resetting the scram is desirable because it stops CRD system flow to the reactor vessel and reduces thermal fatigue to the CRD vessel nozzles; resetting the scram prior to achieving stable plant conditions is not desirable because transient conditions could produce another automatic scram.

18:46:53 Received reactor low water level scram. *The low level condition was due to RCIC injection not commencing at the onset of the HPCI control mode transition due to concern for the unexpected RCIC flow oscillations, greater than anticipated vessel water inventory use in transitioning HPCI to pressure control mode, and loss of the vessel water inventory contribution from the CRD system due to resetting the scram.* (1), (3), (4)

18:48 RCIC flow oscillations stop, operators gradually increase flow to 600 gpm. (6)

18:53:05 Reactor low water level scram signal clear. (4)

18:57 Commenced torus level reduction to radwaste. (1)

This is noted here because the ongoing discharge of HPCI/RCIC turbine exhaust steam (and later, steam from the SRVs) to the torus introduces short-lived (half-life on the order of hours) radionuclides (in the form of dissolved gases) into the torus water. After discharge to the radwaste system, these gases are released to the atmosphere and result in a slight (but measurable) increase in the activity being released from the plant through the plant ventilation system. This is an expected and previously analyzed condition.

18:58:14 Operators secured injecting with RCIC and secured the system. Reactor vessel level control is maintained with the secondary condensate pumps. (7), (10)

19:00 *For the next two hours, the plant is in a relatively stable slow cooldown, maintaining vessel level at about 30 inches with the secondary condensate pumps, and with HPCI operating in pressure control mode at 4000-5000 gpm flow. Pressure decreases from about 650 psig to about 550 psig.* (7)

19:06 Operators reset the reactor scram. (1)

19:10 An RP technician noted water condensing and falling outside of the Administration Building and Turbine Building. The apparent source was steam that had escaped from the turbine building. This was due to pressure in the turbine building exceeding outside atmospheric pressure for a short period, as a result of the steam leak, which caused steam to leak through building penetrations (doors, construction material joints, etc.). (5)

Note that this constitutes an unmonitored radioactive release to the environment, the magnitude of which cannot be precisely quantified. However, based on actual radiation monitoring system measurements and the decrease in plant water inventory over the course of the event, the release is conservatively estimated to have been less than one percent of the regulatory limit. Note also that the design basis steam line failure in the turbine building (far more severe than this event) has been previously analyzed and shown to result in an environmental release that would be within the limits of 10 CFR 100.

20:15 Secured torus level reduction to radwaste. (10)

21:05 HPCI alarm received in the control room, “Overload/Power Fail.” (1)

Operators placed RCIC in service in pressure control mode in anticipation of HPCI being secured. (1), (7), (10)

21:12 Cause of the HPCI alarm determined to be that the thermal overloads for the HPCI barometric condenser vacuum pump had tripped. Operators reset the thermal overloads and restarted the vacuum pump. (1), (10)

21:17 Operators removed RCIC from service. (1), (8)

21:27 HPCI barometric condenser vacuum pump thermal overloads tripped again. (1)

Operators again placed RCIC in service in pressure control mode. (1), (8)

21:31 Operators removed HPCI from service. (1), (8)

HPCI remains operable and available for use, if necessary; operators elect to secure it because continued operation without the barometric condenser vacuum pump would result in steam leakage from the turbine which, in turn, would result in radioactive contamination of the HPCI pump room.

21:31 - 21:38 *Decay heat is beyond the capacity of RCIC in pressure control mode. As a result, reactor vessel water level is increasing due to inventory heatup.* (10)

21:38 Wide range reactor water level reached 54" (level 8) and continuing to rise, RCIC automatically tripped. (1), (3), (8)

21:48	Commenced use of SRVs (one at a time) to augment RCIC pressure control. *Opening an SRV initially produces a rapid increase in vessel water level due to swell, then a rapid decrease due to inventory reduction, and finally, a further decrease due to shrink upon closure*. (1), (8)
	Note that, due to the change in water density as temperature is lowered, the reactor vessel wide and narrow range water level instruments diverge at less than normal operating pressure. For example, at the current reactor pressure of 450-500 psig, a narrow range level of 48 inches corresponds to a wide range level of about 60 inches. The narrow range level instrument provides the low water level scram signal at 12.5 inches (Level 3), and the wide range level instrument provides the high level HPCI/RCIC automatic shutdown signal at 54 inches (Level 8). As a result, controlling water level between these two trip setpoints presents an operational challenge.
21:54	Wide range reactor water level is at 54 inches and decreasing. (8)
21:57	Operators closed the first SRV at about 25 inches (narrow range); subsequent shrink caused reactor water level to decrease below 12.5" (Level 3), received reactor low water level scram. (1), (3), (8)
	Operators returned RCIC to service in pressure control mode. (1), (8), (10)
22:04	RCIC automatically tripped due to reactor water level again reaching level 8. (1)
	Note that RCIC is not operated again for the remainder of the plant cooldown. As a result, vessel level exceeding 54 inches (wide range) no longer presents an operational limitation. Pressure control is by the SRVs.

October 11, 2004

00:31	Completed the last of 10 SRV manual cyclings that had commenced at 21:48. (9)
02:33	Manually opened one SRV; it will remain open for about 24 hours. (9)
14:52	Operators placed RWCU in service. (1)

October 12, 2004

01:13	Commenced operation of RHR in shutdown cooling mode. (1)
02:11	Closed the SRV that had been opened about 24 hours earlier. (9)
05:09	The reactor is in Cold Shutdown. (1)

19:45 "After-the-Fact" report made to the NRC for not meeting TS 3.6.2.3 Action b. to have plant in Cold Shutdown within 24 hours of reaching Hot Shutdown.

Source Codes

1. Control Room Narrative Log. Note: The time of the scram in the log is 18:14, and by the sequence of events printout is 18:12:35. Subsequent events recorded in both do not indicate a consistent offset. Therefore, the team used sequence of events printout times beginning with the scram, and control room narrative log times may have been changed to be consistent with the sequence of events.

2. Simulator Instructor interviews

3. Operator interviews

4. Sequence of Events printout or plant computer printout

5. Notification 20207055

6. 45 minute plant computer graphs (6:05 - 6:50 p.m.) of the following:
   a. Reactor water level
   b. HPCI/RCIC pump discharge flow
   c. Main turbine bypass valve position
   d. Indication for reactor scram, MSIV not full open scram, and RFP Turbine low control oil pressure

7. Five hour plant computer graphs (6:00 - 11:00 p.m.) of the following:
   a. Reactor pressure
   b. Reactor water level
   c. HPCI/RCIC pump discharge flow

8. 1.5 hour plant computer graphs (9:10 - 10:40 p.m.) of the following:
   a. Reactor narrow range level channel A
   b. Reactor wide range level channel B
   c. HPCI/RCIC pump discharge flow
   d. Indication for the first five SRV openings

9. PSEG's Post Reactor Scram Review

10. Root Cause Evaluation, "Reactor Vessel Water Level Control Difficulties," and interview with a senior reactor operator.

ATTACHMENT D

MOISTURE SEPARATOR / DRAIN SYSTEM CHRONOLOGY

Information notes and relevant NRC team assessments notes are shown in *italics*.

Date	Event
10/13/1988	Sometime prior to October 13, 1988: LV-1039A failed open. Within two days, a vacuum leak due to a pipe crack developed on the downstream piping (line AC-8"-GAD-032) near penetration 56 into the condenser. The in-leakage was sufficient to cause concerns about continued operation of the plant. Design modification (DCR) 4-HM-0494 was initiated to correct the vacuum leakage by installing (welding) a mechanical encapsulation at the circumferential crack. LV-1039A was repaired. {Source: DCR 4-HM-0494} *This was a missed opportunity to identify consequences of operating with valve LV-1039A in the failed open position.*
01/06/1990	MS High Level, Turbine Trip, Reactor Scram: During main turbine combined intermediate valve (CIV) testing, the 'A' MS experienced a high level condition. Dump Valve LV-1039A opened, but not in time to prevent a turbine trip on high level. The reported cause was a combination of equipment failure and personnel errors (failure to wait the required time for the turbine control system and MS levels to stabilize). The 'A' and 'B' MS instrumentation loops were tuned at 25% power during restart. {Source: LER 90-001-00}
11/17/1990	MS High Level, Turbine Trip, Reactor Scram: During main turbine CIV testing, the 'A' MS experienced a high level condition. Dump valve LV-1039A began to open, but level continued to rise until it reached the turbine trip setpoint. The cause of the high level was reported as a broken bushing on the hinge pin of the check valve in the normal drain line. This is postulated to have allowed backflow from the #5 feedwater heater, which put additional water in the MS and decreased the effectiveness of LV-1039A to reduce level. A contributing cause was reported to be sluggish operation of LV-1039A since it did not begin to stroke open until 22 seconds after the high level alarm was received in the control room. The check valve was repaired and LV-1039A was disassembled and inspected, and the valve operator stroke time was adjusted. {Source: LER 90-028-01}
11/15/1998	MS High Level, Turbine Trip, Reactor Scram. Operators were in the process of isolating instrument air to a steam seal evaporator level control valve in preparation for a system outage. The instrument air to the normal level control valves for the 'A' and 'B' MSs were inadvertently isolated as a result of an error in the piping and instrumentation diagram. Dump valve LV-1039A failed to open to maintain level. The cause was reported to be sticking from an iron oxide buildup in the plug/seat area. Corrective action was a modification to install appropriate

valve trim/plug material to prevent iron oxide buildup. {Source: LER 98-008-01}

10/26/2001 LV-1039A positioner not responding. Replaced positioner. {Source: Notification 20081426/ Work Order 70020654}

11/29/2001 LV-1039A Seat Leakage (Identified by thermal performance assessment - reduced efficiency): Valve rebuilt in May 2003 during refueling outage. {Work Order 60025008}

06/22/2002 MS High Level, Turbine Trip, Reactor Scram: Cause was 'B' secondary condensate pump trip and resulted in recirculation pump runback. During the runback, MS level increased and LV-1039A failed to stop the level increase. {Source: Notification 20103635/ Work Order 60029413/ LER 2002-004-00}

06/23/2002 LV-1039A Troubleshooting: The probable cause of the failure of LV-1039A to stop the level increase during the June 22, 2002, transient was the transient occurred in such a short period of time that the pneumatic controls did not react fast enough for the dump valves to respond. LV-1039A stroked fully open in 55 seconds compared to 35 seconds for the LV-1039B valve. The LV-1039A valve proportional band was adjusted to be the same as the 'B' side. {Source: Notification 20103635/ Work Order 60029413}

05/07/2003 Installed modification DCP 80051144, intended to reduce the opening time of MS dump valves LV-1039A and 1039B to less than 10 seconds by installing quick exhaust valves for the valve operators. {Source: Notification 20143359/ DCP 80051144}

04/16/2004 LV-1039A Appears to be Leaking: Work Order 60040509 canceled after Thermal Performance Group confirmed on June 9, 2004, that LV-1039A was not leaking. {Source: Notification 20145639/Order 60040509}

09/16/2004 'A' MS Dump Valve Failed Open: {Source: Notification 20203784} Thermal performance/efficiency graph provided by system engineering showed that LV-1039A was dumping significant heat (equivalent to 9 MWe) to the main condenser. The MS 'A' low level alarm came in at same time. A review of computer point data shows that computer point D2602 (LV-1039A Not Closed Limit Switch) changed state. *Post event investigation shows that hanger H25 connection rod was disconnected and was rubbing on the LV-1039A positioner air line. At this point, it appeared that a large enough hole in the airline had been made so that the valve came off its open seat (it requires air pressure to maintain the valve shut). This was a missed opportunity to identify the cause of the open valve and the consequences of operating with it open.*

09/20/2004 Operability assessment for operating with LV-1039A failed 10% open. Operability considered OE regarding damage to condenser while operating on MS dump valves to condenser. The operability assessment reasonably concluded that the condenser will not be damaged and that the condenser is operable. {Source: 20203784} *However, no consideration of two-phase flow in the line from the MS to LV-1039A was documented. Two-phase flow was apparent from the low-level in the MS and from the significant loss of MWe. This was a missed opportunity to recognize the effects of operating with LV-1039A open.*

An operator, not satisfied with the September 20, initiated another notification (No. 20204256) that same day, stating that the prior notification did not appear address the potential impact to the condenser penetration which had cracked on an earlier occasion, when this same dump valve had failed open for an extended period of time (resulting in elevated offgas flow due to increased inleakage through the crack at the penetration to the condenser). {Source: Notification 20204256} *Again, a formal engineering response, completed on September 22, did not address the part of the concern related to the prior experience with the dump valve open. This was another missed opportunity to recognize the effects of operating with LV-1039A open.*

10/4/2004 A review of computer point data shows that computer point D2603 (LV-1039A Open Limit Switch) changed state several times in 20 minutes. *A likely scenario is that as the hole in the air line became larger because of the hanger rubbing, the valve opened toward its full open position such that the open limit switch actuated. Since the air pressure was low and two-phase flow was causing pipe and valve movement, the limit switch was bumped several times before air pressure bled off enough to keep the limit switch actuated. This was a missed opportunity to recognize failure was degrading, investigating cause of degradation, and identifying cause of failure.*

10/10/2004 MS Dump Line Piping Failed at Condenser Penetration {Source: Notification 20206626}

ATTACHMENT E

REACTOR VESSEL LEVEL INSTRUMENT DEFINITIONS / RANGES

Reactor vessel level is measured through different ranges with diverse and independent instrumentation. The level ranges and definitions are listed below:

Level Setpoint Definitions

Level 8	+54 inches:	High Level Trip Setpoint for HPCI and RCIC
Level 7	+39 inches:	High Level Alarm Setpoint
Level 4:	+30 inches:	Low Level Alarm Setpoint
Level 3:	+12.5 inches:	Low Level Scram Setpoint Signal to the RPS
Level 2:	-38 inches:	HPCI, RCIC Initiation Setpoint, Some Containment Valve Isolations, Reactor Recirculation Pump Trip Setpoint
Level 1:	-129 inches:	ECCS Initiation Setpoint (Core Spray, RHR, EDG start signals), Additional Containment Isolations

Reference Values

- Normal Reactor Vessel Level (routine, full power operation): +35 inches
- Top of Active Fuel: -161 inches (which is about 10 feet below Level 2)

Level Instrument Ranges

Narrow Range Instrumentation:	0 inches to +60 inches: Provides Input to RPS Scram and Main and Reactor Feed Pump Turbine High Level Trip
Wide Range Instrumentation:	-150 inches to +60 inches: Provides Trip and Initiation Inputs to HPCI and RCIC, Auto Start to EDGs, and Signal for Containment Isolations.

Note: During a plant cooldown, the density of the water is affected; it becomes more dense (heavier). This change in density affects the water level transmitters, which measure the weight of water in the reactor vessel. During a cooldown, the water that becomes more dense would cause a higher than actual level indication. Both the narrow and wide range transmitters are affected by this phenomenon; and, in fact, because the wide range instruments have a much larger span than the narrow range (210 inches vs. 60 inches), the effect is roughly tripled on the wide range instruments. This becomes a factor during a plant cooldown, as operators control reactor vessel level between Level 3 and Level 8. Each range of the instruments causes different actuations, so operators control reactor vessel level to the equivalent of a more narrow control band (as the indicated wide range instruments approach the Level 8 setpoint).