U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Report Nos.	50-334/96-07, 50-412/96-07
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Licensee:	Duquesne Light Company (DLC) Post Office Box 4 Shippingport, PA 15077
Facility:	Beaver Valley Power Station, Units 1 and 2
Inspection Period:	August 13, 1996 through September 28, 1996
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EXECUTIVE SUMMARY

Beaver Valley Power Station, Units 1 & 2
NRC Inspection Report 50-334/96-07 & 50-412/96-07

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections by regional inspectors in the areas of engineering and radiological controls.

<u>Operations</u>

- Good command and control was exercised by the Nuclear Shift Supervisor (NSS) and the Assistant NSS during the August 30, Unit 2 shutdown. Good three-way communications were used, and distractions in the control room were minimized (Section O1.2).

- Feedwater regulating valve bypass valve leakage resulted in excessive reactor coolant system cooldown during the Unit 2 shutdown while below 1% reactor power. Operators were prompt to identify the potentially leaking bypass valve. Operators demonstrated sound safety judgement and manually tripped the reactor when primary temperature reached the minimum temperature for criticality limit, rather than continuing to investigate the cause during the time allowed by technical specifications (TS) (Section O1.2).

- Control of Unit 2 refueling activities, including loop isolation and draindown, core offload, and core reload was excellent. Operators and engineering staff worked well together in ensuring evolutions were completed safely, and unexpected conditions were evaluated and corrected in an approved and methodical manner. Close vendor oversight was maintained during refueling activities (Section O1.3).

- The inspectors determined that Unit 1 normal switch alignment for pressurizer power operated relief valve (PORV) block valves was not properly restored following piping modifications completed in 1981. The unit continued to operate with two PORV block valves shut for over fifteen years contrary to the Updated Final Safety Analysis Report specified configuration. Appropriate corrective actions were initiated this report period to restore the design system configuration and to evaluate causal factors for this event. This item is unresolved pending further inspector evaluation of causal factors, extent of condition, safety significance, and corrective action implementation (Section O1.4).

- On August 20, operators failed to provide administrative control of containment isolation valves as required by TS during the Unit 1 startup (Section O8.1).

Maintenance

- The 2-2 emergency diesel generator (EDG) experienced two unplanned overspeed trips during post speed governor replacement testing. Senior management involvement was necessary to ensure the event was evaluated and resolved in a timely manner. Work ownership, vendor oversight, and procedural weaknesses were identified (Section M1.1).

Engineering

- Significant improvement in engineering department workload management was noted. The engineering backlog was effectively reduced (Section E1.3).

- Material engineers performed an excellent assessment of the boric acid leakage and corrosion of the Unit 2 reactor vessel head. Vendor and industry information was effectively integrated into the evaluation (Section E2.1).

- Ultrasonic testing results revealed that two Vantage 5H type fuel assemblies each had one leaking fuel pin. Engineers effectively identified two leaking fuel pins and responded appropriately to a broken fuel pin during fuel assembly reconstitution (Section E2.2).

- A previously unresolved item concerned licensee determination that a small increase in the probability of equipment failure did not constitute an unreviewed safety question. The inspectors determined that the safety evaluation for river water line excavation performed in 1994 was inadequate (Section E8.1).

- An unresolved item regarding fire pump capacity was closed (Section E8.2).

- Initial engineering response to recently identified containment penetration overpressurization concerns was excellent. This issue remains unresolved for Unit 1 (Section E8.3).

Plant Support

- Overall, performance in the radiological protection (RP) area by RP staff was considered to be good. Radiological controls established during the Unit 2 refueling outage were considered well planned and appropriate. The outage RP organization was well staffed to meet the outage workload. Efforts to control and minimize radioactive waste generation appeared successful. The licensee identified an improper entry into a high radiation area (Sections R1.0 through R8.2).

- The inspectors observed isolated examples of radiological control and housekeeping discrepancies which indicated a need for increased attention to detail during routine area tours (Section R8.3).

- Inadequate enforcement of safeguards control standards and policies by Maintenance Department management led to loss of control over safeguards information. The weaknesses had existed for several years. Appropriate corrective actions have been implemented. Failure to adequately control safeguards information and failure to conduct an annual inventory was a Violation of the Beaver Valley Power Station Physical Security Plan (Section S3.1).

Safety Assessment and Quality Verification

- The recently established Nuclear Safety Review Board (NSRB) effectively reviewed safety issues this period and made appropriate recommendations to the plant manager. The NSRB's broad perspective was evident as demonstrated by the range of discussion, causal assessment, and corrective action items assigned. NSRB members were sensitive to avoid work arounds and assess various corrective action alternatives for their potential impact on station operators. The NSRB charter and a TS amendment request associated with the intended oversight role were initiated (Section O7.1).

- The Quality Service Unit discontinued audits of the Onsite Safety Committee (OSC) after March 1992. The inspectors determined that failure to audit OSC activities under the cognizance of the Offsite Review Committee was a Violation (Section O8.3).

- The post event review of unplanned 2-2 EDG overspeed trips during maintenance was thorough and developed insightful, well focused findings (Section M1.1).

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Report Details

Summary of Plant Status

Unit 1 began the inspection period in Mode 5 (cold shutdown) in a forced outage to repair a component cooling water leak into a reactor coolant pump upper bearing lube oil reservoir and to modify relief protection on some containment penetrations. DLC returned the unit to service on August 22, following completion of outage work. Unit 1 remained at full power for the remainder of the period.

Unit 2 began the inspection period at 94% power in coastdown toward the sixth refueling outage. On August 30, DLC commenced plant shutdown from 46% power to enter the outage. While inserting control rods for entry into Mode 3 (hot standby), operators initiated a manual reactor trip due to reactor coolant temperature decreasing to 541 degrees F due to excessive feedwater regulating valve bypass valve leakage. The trip is discussed further below in section O1. After the trip, the shutdown and cooldown to Mode 5 continued without incident. Unit 2 entered Mode 6 (refueling) on September 6 and remained in the outage for the remainder of the period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)[1]

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious. Specific events and noteworthy observations are detailed in the sections below.

O1.2 Unit 2 Shutdown and Manual Trip

a. Inspection Scope (71707)

Inspectors monitored the Unit 2 shutdown on August 30 to enter the refueling outage and reviewed the circumstances surrounding the operators' decision to insert a manual reactor trip during the power reduction.

b. Observations and Findings

Inspectors observed the Unit 2 plant shutdown on August 30 for the sixth refueling outage, including load reduction, removal of the main generator from service, turbine pedestal checks, and subcritical operations. Prior to the evolution, inspectors had also monitored the shutdown training given to the crew in the

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[1]Topical headings such a O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

simulator the previous day. The simulator training served to refresh the crew on the procedure and potential problems and establish communications patterns. Inspectors noted that the timely refresher training was a good DLC initiative.

Plant operations were controlled in accordance with procedures 2OM-52.4.C, "Decreasing Power from ≤40% to Turbine Shutdown and Reactor at Approximately 5% Power," and 2OM-51.4.A, "Station Shutdown-Minimum Load to Startup Mode or Hot Standby Mode." A senior operations manager was in the control room throughout the shutdown, and it was briefed beforehand as an infrequent evolution. Good command and control of the evolution was exercised by the Nuclear Shift Supervisor (NSS) and the Assistant NSS (ANSS). Inspectors noted deliberate plant control by the crew throughout the evolution. Good three-way communications were used, and distractions in the control room were minimized.

The main generator was taken off line at 7:21 PM. The governor valves closed to maintain the turbine spinning at 1800 RPM for pedestal checks, resulting in reduced flow to the high pressure turbine and reduced extraction steam flow to the high pressure feedwater heaters, causing feedwater temperature to decrease rapidly. Pedestal checks were completed and the turbine was tripped at 8:04 p.m. At 8:36 p.m., operators noted steam generator "A" level increasing above the expected level. Operators immediately investigated potential causes. Level continued to increase despite the feed station operator closing the feedwater regulating valve bypass valve (2FWS-FCV479).

At 8:49 p.m., reactor power was in the intermediate range at about 10E-7 amps and operators were inserting control rods to place the unit in Mode 3 (hot standby) when reactor coolant average temperature reached to 541 degrees F, the technical specification (TS) low limit for criticality. The TS allows 15 minutes to recover temperature, and one available option was to withdraw control rods to stop the temperature decrease However, operators considered that they were already in the process of driving rods in to zero steps and did not have conclusive evidence of the root cause of the temperature decrease. They decided to insert a manual reactor trip as a prudent action rather than keep the plant in an intermediate condition. At 8:51 p.m., operators shut the feedwater regulating valve bypass valve block valve. The steam generator level increase and reactor temperature decrease immediately stopped.

The unit responded as expected to the trip. Reactor temperature stabilized at 547 degrees F. Due to the operators prompt action in shutting the block valve, no engineered safety features actuations occurred. The event was reported to the NRC in accordance with 10 CFR 50.72.

DLC's subsequent evaluation concluded that the apparent cause of the event was a leaking feedwater regulating valve bypass valve, which, together with the reactor power reduction, caused a power mismatch and subsequent decrease in primary temperature.

DLC's corrective actions were still under development at the end of the period. They included several procedural enhancements regarding control of turbine pedestal testing, steam generator blowdown control and level monitoring, and steam dump monitoring designed to strengthen control of parameters that effect primary temperature at low reactor power. DLC's post-shutdown testing did not demonstrate that the bypass valve was leaking; however, additional testing and monitoring was planned during the startup from the outage.

c. Conclusions

Good command and control of the Unit 2 shutdown was exercised by the Nuclear Shift Supervisor (NSS) and the Assistant NSS (ANSS). Inspectors noted deliberate plant control by the crew throughout the evolution. Good three-way communications were used, and distractions in the control room were minimized.

Operators responded deliberately and promptly to rising steam generator level and lowering reactor coolant temperature during the shutdown. The apparent cause was a leaking feedwater regulating valve bypass valve, which, together with the reactor power reduction, caused a power mismatch and subsequent decrease in primary temperature. The decision was prudent to manually trip the reactor when primary temperature reached the temperature limit, rather than continue to investigate the cause during the time allowed by TS. Operators promptly identified the potentially leaking bypass valve and took appropriate actions.

O1.3 Refueling Activities (Unit 2)

a. Inspection Scope (71707)

Inspectors observed selected refueling activities associated with the Unit 2 outage. Observations included loop isolation and draindown, core offload, and core reload.

b. Observations and Findings

Loop isolations and draindowns were completed in a deliberate manner with close attention to level indications, good communications between the control room operators and assistant shift supervisor and the field, and oversight by operations management. The evolution was briefed beforehand as an infrequent evolution with a dedicated evolution manager. Inspectors walked down the reactor coolant system (RCS) temporary level indication standpipes to verify conformance to procedure 2OM-6.4I, "Draining the RCS for Refueling." Operators were alert and closely controlled draindown rate to ensure that all level indicators remained within tolerance limits. The evolutions were completed without incident.

Core offload and reload were also well-controlled by the refueling senior reactor operators. Foreign material exclusion and personnel access controls for the refueling cavity were excellent. The controlled area tools attendant maintained a strong questioning attitude regarding personnel and material entry. Operators observed that two fuel assemblies were slightly bowed. The load sequence was

effectively adjusted and the assemblies were safely reloaded. Fuel handling discrepancy reports were written to document and evaluate the two bowed assemblies. The inspectors observed that refueling personnel were not periodically reading their self alarming dosimetry to monitor their current accumulated radiation exposure. This issue was addressed with Health Physics supervision and appropriate corrective action was implemented.

The gripper up disengaged refueling bridge interlock alarm was received with about 50 assemblies remaining to be reloaded. The inspectors discussed the alarm and other refueling bridge interlocks with the operators. Operators appropriately modified the refueling mast lifting height to address the interlock. The inspectors concluded that the operators were knowledgeable of fuel handling equipment and procedures. Operators maintained close oversight and communications with vendor personnel during fuel handling. Excellent support was provided by reactor engineering staff. Core offload and reload were completed without significant incident.

c. Conclusions

Overall, inspectors noted excellent control of refueling activities. Operators and engineering staff worked well together in ensuring evolutions were completed safely, and unexpected conditions were evaluated and corrected in an approved and methodical manner. Close vendor oversight was maintained during refueling activities.

O1.4 Unit 1 Pressurizer Power Operated Relief Valve (PORV) Block Valve Configuration

a. Inspection Scope (71707)

The inspectors conducted control board walkdowns to verify equipment was properly aligned consistent with plant design and current operating mode.

b. Observations and Findings

Incorrect Configuration Identified

The inspectors observed that two of three Unit 1 pressurizer (PZR) PORV block valves (MOV-RC-535 and 536) were shut and asked the reactor operator why they were in this position. The operator responded that shut was the normal position for these valves as specified by station procedures and system drawings. Operators were trained that this configuration reduced the likelihood and magnitude of a potential reactor coolant system (RCS) depressurization due to stuck open PZR PORVs. The inspectors noted that Unit 2 normally operated with all three PORV block valves open and further questioned the basis for the Unit 1 configuration.

The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) to determine the system design configuration position. UFSAR 4.2.2.7 states that the PORVs limit PZR pressure to a value below the high-pressure reactor trip setpoint for all design transients up to and including the design (102%) step load decrease

with steam dumps operable but without a reactor trip. The PORVs also limit the undesirable opening of the spring-loaded PZR code safety valves. The PORV block valves are provided to isolate the PORVs if excessive leakage occurs. Based on discussions with the control room staff, the inspectors determined the PORVs had not exhibited excessive leakage. Failure of all three PORVs on a design load reject is analyzed in UFSAR 14.1.7. Code safety valves operate to protect reactor coolant system (RCS) integrity. However, the licensee had not evaluated peak PZR pressure on a design load reject with two PZR PORVs blocked and could not demonstrate that PZR pressure would remain below the high-pressure reactor trip setpoint. The inspectors informed operations and licensing personnel that the current Unit 1 PZR PORV block valve configuration was inconsistent with system design and requested they evaluate the issue.

Licensee Assessment and Corrective Actions

Engineers evaluated the issue and presented their findings to the Nuclear Safety Review Board (NSRB). Engineers determined that the two block valves had been shut in 1980 to address seismic concerns for downstream PZR PORV piping which were identified during evaluation of NRC Bulletin 79-14, "Seismic Analyses for As-Built Safety-Related Piping Systems". In 1981, seismic modifications for PZR PORVs were implemented which resolved the PZR PORV piping seismic concerns. However, the two block valves were not reopened and operators continued normal operation with the valves shut through this current report period. No documentation of the decision to maintain the block valves shut was found.

Engineers presented a safety evaluation to the NSRB, which recommended that the PORV block valve configuration be changed to open MOV-RC-535 and 536. Probablistic risk assessment (PRA) evaluations determined that operation with all three PORV block valves open would result in a meaningful total core damage frequency (CDF) reduction. The safety evaluation noted that the proposed valve configuration change does not require UFSAR revision and was not an unresolved safety question (USQ). The inspectors reviewed the safety evaluation and determined that the proposed PORV block valve configuration revision was not an USQ.

NSRB members concurred with the safety evaluation recommendation and asked excellent questions regarding implementation. Issues included prerequisite procedure and training revisions which may be necessary to support revision of this longstanding configuration; and an "extent of condition" review for other GL 79-14 closeout activities. The Operations manager issued a night order to all licensed personnel to ensure they understood that, pending the valve configuration change, Unit 1 RCS pressure may peak higher than previously assumed in the UFSAR during turbine load reject transients. The inspectors concluded that NSRB issue review was comprehensive and that recommended corrective actions were appropriate.

c. Conclusions

The inspectors determined that the normal switch alignment for Unit 1 PZR PORV block valves was not properly restored following piping modifications completed in 1981. The Unit continued to operate with two PORV block valves shut for the past fifteen years contrary to the UFSAR specified configuration. Appropriate corrective actions were initiated this report period to restore the design system configuration and to evaluate causal factors for this event. This item is unresolved pending further inspector evaluation of causal factors, extent of condition, safety significance, and corrective action implementation **(URI 50-334/96007-01)**.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdowns (71707)

The inspectors walked down accessible portions of selected systems to assess equipment operability, material condition, and housekeeping. Minor discrepancies were brought to DLC staff's attention and corrected. No substantive concerns were identified. The following systems were walked down:

- Unit 1 Emergency Diesel Generator Start Air
- Unit 1 Emergency Diesel Generator Fuel Oil
- Unit 1 Emergency Switchgear Breaker Alignment

O7 Quality Assurance in Operations

O7.1 Nuclear Safety Review Board (NSRB)

a. Inspection Scope (71707, 40500)

Earlier this year NRC inspectors and senior licensee management expressed concerns regarding Onsite Safety Committee (OSC) performance (see NRC IR No. 50-334(412)/95-05) . The NSRB was established in July 1996 to address these concerns and provide a broader overview of plant operations. The inspectors observed NSRB activities to evaluate this new group's effectiveness at reviewing safety issues.

b. Observations and Findings

The NSRB was formed as an oversight committee to provide recommendations to the plant manager regarding safe plant operations. The inspectors observed several NSRB meetings during the inspection period. On September 25, 1996, the NSRB met to review four issues; two LERs prior to issuance, boric acid stains on the Unit 2 reactor vessel head, and potential discrepancies in the Unit 1 pressurizer (PZR) power operated relief valve (PORV) configuration. The NSRB was comprised of several key managers including the Operations, Maintenance, Health Physics, Chemistry, System & Performance Engineering, Nuclear Engineering, and Nuclear Safety unit managers and was chaired by the Vice President-Nuclear Services.

Issue managers, who were not members of the NSRB, made detailed presentations of their issue, causal factors, and proposed corrective actions. NSRB members asked probing questions. The benefit of their broad perspective was evident as demonstrated by the range of discussion, causal assessment, and corrective action items assigned. NSRB members were sensitive to avoid work arounds and assess potential impact on station operators for the various corrective action alternatives.

The inspectors noted that the NSRB role and responsibilities had not been defined in a formal charter and questioned how the NSRB would interface with the Onsite Safety Committee (OSC) whose role is specified in TS. Management indicated that the NSRB would review proposed TS changes, LERs before issuance, basis for continued operations, licensing submittals, emergency plans, event response reports, 10 CFR 50.59 evaluations, and temporary modifications. Over time management intends to reduce OSC activity scope, to function as a subcommittee to the NSRB. The licensing manager informed the inspectors the NSRB charter was being formalized and that a TS amendment request would be submitted as necessary to support the new oversight relationship.

c. Conclusions

The inspectors concluded that the NSRB effectively reviewed safety issues this period and made appropriate recommendations to the plant manager. The NSRB's broad perspective was evident as demonstrated by the range of discussion, causal assessment, and corrective action items assigned. NSRB members were sensitive to avoid work arounds and assess various corrective action alternatives for impact on station operators. The NSRB charter and a TS amendment request associated with the intended oversight role were initiated.

O8 Miscellaneous Operations Issues (71707, 92700)

O8.1 (Open) Licensee Event Report (LER) 50-334/96011: Failure to Provide Administrative Control of Containment Isolation Valves as Required by Technical Specifications (TSs). During Unit 1 startup on August 20, operators identified that they had failed to station an operator in continuous communication with the control room at the manual containment isolation valves for component cooling water (CCR) to the residual heat removal (RHR) system after entering Mode 4. The operator is required by TS 3.6.3.1 in Modes 1-4 whenever a normally shut containment isolation valve is open. The CCR to RHR valves were open to provide required cooling during the unit startup. Unit 1 had gone from Mode 5 to Mode 4 and was in Mode 4 for about 5.5 hours before operators realized the oversight.

As immediate corrective action, an operator was dispatched to the valves to establish and maintain communication with the control room. There were no adverse safety consequences to the event.

DLC determined that the existing plant startup procedures did not adequately emphasize the TS requirement for the administrative control of the containment isolation valves. The requirements were adequately stated in the plant shutdown

procedures. As long term corrective actions, DLC modified the applicable operating and surveillance test procedures to improve the procedural guidance. Inspectors reviewed the changes to procedures 1OM-50.4.B, 1OST-47.2, and 1OST-50.1 and noted the added precautions. DLC intends to make additional enhancements to 1OM-50.4.B by October 31. Preliminary DLC review indicated that the issue does not apply to Unit 2. NRC review of this LER remains open pending completion of DLC corrective actions.

Failure to station an operator as required by TS 3.6.3.1 as clarified by the TS Basis is a violation of NRC requirements; however, this licensee-identified and corrected violation is being treated as a Non-Cited Violation in accordance with Section VII.B.1 of the NRC Enforcement Policy **(NCV 50-334/96007-02)**.

O8.2 (Open) LER 50-412/96004: Bypass Feedwater Regulating Valve Leakage Leads to Manual Reactor Trip During Shutdown for Refueling. The event was documented in section O1.2. The LER remains open pending review of DLC's corrective actions.

O8.3 (Closed) Unresolved Item (URI) 50-334(412)/96005-01: OSC Activities - a TS Requirement.

a. Inspection Scope

During a self-assessment program review the inspectors noted that the last QA audit of OSC activities was performed in March 1992. The periodic audit was discontinued based on the assessment that this audit was not providing significant findings. The inspectors questioned whether discontinuing the audit of OSC activities was consistent with TS 6.5.2.8 requirements. The licensee stated that audits of OSC activities were not required by TS. The inspectors performed a detailed NRC requirements review to determine whether periodic audits of OSC activities were required.

b. Observations and Findings

Regulatory Requirements Related to the Review and Audit Provisions in Technical Specifications

Paragraph (b)(6)(ii) of § 50.34, "Contents of applications; technical information," requires that the facility's final safety analysis report include, concerning facility operation, the "Managerial and administrative controls to be used to assure safe operation." This paragraph also states: "Appendix B, 'Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,' sets forth the requirements for such controls for nuclear power plants and fuel reprocessing plants. The information on the controls to be used for a nuclear power plant or a fuel reprocessing plant shall include a discussion of how the applicable requirements of Appendix B will be satisfied."

Criterion I, "Organization," of Appendix B to 10 CFR Part 50, states, in part, that "The quality assurance functions are those of (a) assuring that an appropriate quality assurance program is established and effectively executed and (b) verifying, such as by checking, auditing, and inspection, that activities affecting the safety-related functions have been correctly performed."

Regulatory Guide (RG) 1.33, "Quality Assurance Program Requirements (Operation)," Revision 2 (February 1978) describes a method acceptable to the NRC staff for compliance with the provisions of Appendix B to 10 CFR 50 for the operation phase of nuclear power plants. RG 1.33 conditionally endorses the American National Standards Institute (ANSI)/American Nuclear Society (ANS) standard ANSI N18.7-1976/ANS-3.2, "American National Standard - Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." Section 4 of ANSI N18.7/ANS-3.2 provides that programs for reviews and for audits of activities affecting safety shall be established, and that such programs for reviews and audits shall, themselves, be periodically reviewed for effectiveness. Section 4.4, "Review Activities of the Onsite Operating Organization," of ANSI N18.7/ANS-3.2 states, in part, "The onsite operating organization shall provide, as part of the normal duties of plant supervisory personnel, timely and continuing monitoring of operating activities to assist the Plant Manager in keeping abreast of general plant conditions and to verify that day-to-day operating activities are conducted safely and in accordance with applicable administrative controls. These continuing monitoring activities are considered to be an integral part of the routine supervisory function and are important to the safety of plant operation." Section 4.4 also states that "The onsite operating organization should screen subjects of potential concern to independent reviewers and perform preliminary investigations (see 4.3.4)."

The quality assurance (QA) program description in the Updated Final Safety Analysis Report (UFSAR) includes a commitment to ANSI N18.7-1976/ANS-3.2, as endorsed by RG 1.33, in order to comply with the requirements of Appendix B to 10 CFR 50.

Chapter 12.4, "Review and Audit," of the Beaver Valley Power Station, Unit 1 (BVPS-1) UFSAR states "The Onsite Safety Committee (OSC) advises the General Manager Nuclear Operations on all matters related to nuclear safety. The function, composition, responsibilities, authority, quorum and meeting requirements of the OSC are given in TS. The Offsite Review Committee (ORC) provides independent review and audit of designated activities. The function, composition, responsibilities, authority, quorum and meeting requirements of the ORC are given in TS."

Chapter 13.4, "Review and Audit," of the Beaver Valley Power Station, Unit 2 (BVPS-2) UFSAR states "A review and audit program has been established by Duquesne Light Company (DLC) to Assure that operations of its nuclear power plants are performed in a safe manner consistent with license provisions, approved procedures, and company policy. The review program is the responsibility of the OSC and the ORC. The audit program is the responsibility of the Operations Quality

Assurance Department. The functions of the review and audit program are detailed as follows: (1) Review proposed changes, tests, experiments, and implementing procedures pursuant to the criteria established in 10 CFR 50.59; (2) Verify that unusual events are promptly investigated and corrected; (3) Detect trends of conditions that may not be apparent to a day-to-day observer."

Section 13.4.1, "Onsite Review," of BVPS-2 UFSAR states "The OSC has been established to advise the General Manager, Nuclear Operations, on all matters related to nuclear safety. In this capacity, the OSC will review plant operations, changes, experiments, tests, and procedures that have nuclear safety significance. The OSC also functions to determine what items constitute an unreviewed safety question and will request review of these items by the ORC."

Section 13.4.2, "Independent Review," of BVPS-2 UFSAR states "The ORC has been established to review and audit all matters that involve safety considerations relating to the operation of BVPS. The primary purpose of the committee is to ensure that the station is operated in a manner consistent with the terms of the operating license and in accordance with applicable regulations that are designed to safeguard the health and well-being of station personnel and the general public."

Paragraph (c)(5), "Administrative controls" of 10 CFR 50.36, "Technical specifications," states that "Administrative controls are the provisions relating to organization and management, procedures, record keeping, review and audit, and reporting necessary to assure operation of the facility in a safe manner." The following requirements related to OSC and ORC activities are specified by Beaver Valley's TS 6.5, "Review and Audit":

(a) OSC

(1) TS 6.5.1.1 - "The OSC shall function to advise the General Manager, Nuclear Operations on all matters related to nuclear safety and shall provide review capability in the areas of: a. nuclear power plant operations; b. radiological safety; c. maintenance; d. nuclear engineering; e. nuclear power plant testing; f. technical advisory engineering; g. chemistry; h. quality control; and i. instrumentation and control."

(2) TS 6.5.1.6 - "The OSC shall be responsible for: a. Review of 1) all procedures required by Specification 6.8 and changes of intent there to, 2) any other proposed procedures or changes thereto as determined by the General Manager Nuclear Operations to affect nuclear safety; b. Review of all proposed tests and experiments that affect nuclear safety; c. Review of all proposed changes to the TS; d. Review of all proposed changes or modifications to plant systems or equipment that affect nuclear safety; Investigations of all violations of the TS including the preparation and forwarding of reports covering evaluations and recommendations to prevent recurrence to the General Manager, Nuclear Operations and to the Chairman of the Offsite Review Committee; f. Review of all REPORTABLE EVENTS; g. Review of facility operations to detect potential safety hazards; and h.

Performance of special reviews, investigations or analyses and reports thereon as requested by the Chairman of the ORC."

(3) TS 6.5.1.7 - "The OSC shall: a. Recommend to the General Manager, Nuclear Operations written approval or disapproval of items considered under 6.5.1.6.a through .e above; b. Render determinations in writing with regard to whether or not each item considered under 6.5.1.6.a through .e above constitutes an unreviewed safety question; and c. Provide written notification within 24 hours to the Senior Vice President, Nuclear Power Division and the Offsite Review Committee of disagreement between the OSC and the General Manager, Nuclear Operations; however, the General Manager, Nuclear Operations shall have responsibility for resolution of such disagreements pursuant to 6.1.1 above."

(b) ORC

(1) TS 6.5.2.8 - Audits of facility activities, encompassing (in part) the following, shall be performed under the cognizance of the ORC: "[TS 6.5.2.8.]d. The performance of activities required by the Quality Assurance Program to meet the criteria of Appendix 'B', 10 CFR 50."

(2) TS 6.5.2.7 - "The ORC shall review: a. The safety evaluations for 1) changes to procedures, equipment, or systems and 2) tests or experiments completed under the provisions of Section 50.59, 10 CFR, to verify that such actions did not constitute an unreviewed safety question; b. Proposed changes to procedures, equipment or systems which involve an unreviewed safety question as defined in Section 50.59, 10 CFR; c. Proposed tests or experiments which involve an unreviewed safety question as defined in Section 50.59, 10 CFR; d. Proposed changes in Technical Specifications or licenses; e. Violations of applicable statutes, codes, regulations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having nuclear safety significance; f. Significant operating abnormalities or deviations from normal and expected performance of plant equipment that affect nuclear safety; g. ALL REPORTABLE EVENTS (sic); h. All recognized indications of an unanticipated deficiency in some aspect of design or operation of safety-related structures, systems, or components; i. Reports and meeting minutes of the OSC; and j. The results of the Radiological Environmental Monitoring Program prior to submittal of the annual report provided in accordance with Specification 6.9.1.10."

Accordingly, OSC and ORC activities are an inherent part of the administrative controls provisions necessary to assure operation of the facility in a safe manner pursuant to 10 CFR 50.34(b)(6)(ii) and, as described in the TS and UFSAR, such activities are required by the Quality Assurance Program to meet the criteria of Appendix B to 10 CFR 50 and TS 6.5.2.8.d.

Regulatory Requirements Related to Audit Provisions in the Beaver Valley Power Station Quality Assurance Program Description

10 CFR 50.34(b)(6)(ii), "Contents of applications; technical information," requires that the facility's safety analysis report include, concerning facility operation, the "Managerial and administrative controls to be used to assure safe operation. Appendix B, to 10 CFR 50, 'Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,' sets forth the requirements for such controls for nuclear power plants and fuel reprocessing plants. The information on the controls to be used for a nuclear power plants or a fuel reprocessing plant shall include a discussion of how the applicable requirements of appendix B will be satisfied."

Criterion XVIII, "Audits," of Appendix B to 10 CFR 50 states, in part, "A comprehensive system of planned and periodic audits shall be carried out to verify compliance with all aspects of the quality assurance program and to determine the effectiveness of the program."

Section 13.4.3, "Audit Program," of BVPS-2 UFSAR states "A comprehensive system of planned and documented audits will be instituted at BVPS-2 to verify compliance with the following: 1. Regulatory requirements, 2. License provisions, 3. Operating procedures, and 4. Operations quality assurance program administrative controls." Section 13.4.3.1, "Responsibility," states, in part, "Additionally, the ORC will conduct technically oriented audits within the Nuclear Division as delineated by the Operations Quality Assurance Program."

Section 13.4.3.2, "General Description," of BVPS-2 UFSAR states, in part, "The audit program will include a system of internal audits of station quality related activities, including quality control activities, to assure conformance to the Operations Quality Assurance Program."

The QA program description contained in the UFSAR includes a commitment to RG 1.144, "Auditing of Quality Assurance Programs for Nuclear Power Plants," Revision 1 (September 1980) which provides the licensee's methodology for complying with the audit provisions of Appendix B to 10 CFR 50. RG 1.144 conditionally endorses ANSI/American Society of Mechanical Engineers (ASME) standard N45.2.12-1977, "Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants." RG 1.144 provides that for internal licensee audits during the operational phase, the relevant guidance in RG 1.33 should be followed for the identification of operational activities and/or areas to be audited.

As stated above, the QA program description in its UFSAR also includes a commitment to ANSI N18.7-1976/ANS-3.2, as endorsed by RG 1.33, in order to comply with the requirements of Appendix B to 10 CFR 50 during the operational phase. Section 4.5, "Audit Program," of ANSI N18.7-1976/ANS-3.2 states, in part, "A comprehensive system of planned and documented audits shall be carried out to verify compliance with all aspects of the administrative controls and the quality assurance program. Audits of selected aspects of operational phase activities shall be performed with a frequency commensurate with their safety significance and in

such a manner as to ensure that an audit of all safety-related functions is completed within a period of two years." Section 4.5 also states that "Periodic reviews of the audit program shall be performed by the independent review body or by a management representative at least semiannually to assure that audits are being accomplished in accordance with requirements of technical specifications and of this standard."

Additionally, Section IV.B., "Quality Services Audit Program," of procedure NPDAP 8.21, "Quality Services Audit, Surveillance, Inspection, Examination and Assessments Programs," currently provides, in part, that the Quality Services Audit and Surveillance Department shall audit company groups, departments and programs, and that a twelve month audit schedule shall be developed and maintained by Quality Services Supervisors which lists all areas scheduled to be audited.

Based on the above, failure to perform an audit (under the cognizance of the ORC) of OSC activities at Beaver Valley since 1992 constitutes a violation of Criterion XVIII of Appendix B to 10 CFR 50.

Regulatory Requirements Related to Control of Changes in QA Program Descriptions Previously Approved by the NRC

10 CFR 50.54(a)(1), "Conditions of licenses," states that "Each nuclear power plant or fuel reprocessing plant licensee subject to the quality assurance criteria in Appendix B of this part shall implement, pursuant to 10 CFR 50.34(b)(6)(ii) of this part, the quality assurance program described or referenced in the Safety Analysis Report, including changes to that report." Additionally, 10 CFR 50.54(a)(3) states, in part, "After March 11, 1983, each licensee described in paragraph (a)(1) of this section may make a change to a previously accepted quality assurance program description included or referenced in the Safety Analysis Report, provided the change does not reduce the commitments in the program description previously accepted by the NRC."

The inspectors determined that based on 10 CFR 50.54(a)(3), if a QA program description commitment which defines a requirement for a specific activity (e.g., periodic audits of OSC activities) is being changed by a licensee, and if that particular requirement was being eliminated by the change, the resulting change would constitute a reduction in commitments and would require NRC approval prior to its implementation. Furthermore, if a QA program commitment being changed or modified permits new or alternative options to be used, the change would also constitute a "reduction in commitments" and NRC approval would still be required, even when such new or alternative options are deemed acceptable, or equivalent in effect to the QA commitment being changed or modified, by the licensee.

The QA program description in its UFSAR includes a commitment to ANSI N18.7-1976/ANS-3.2, as endorsed by RG 1.33, in order to comply with the requirements of Appendix B to 10 CFR 50. Based on this commitment, the Quality Services Audit and Surveillance Department is required to periodically perform audits of

selected aspects of operational phase activities with a frequency commensurate with their safety significance, i.e., within a period of two years.

Based on the above, the decision to discontinue performing audits of OSC activities since 1992 constitutes a "reduction in commitments" in the QA program description previously accepted by the NRC. Such a reduction in commitments has effected a change in implementation not currently described in Beaver Valley's QA program description. Pursuant to 10 CFR 50.54(a)(3), Duquesne Light Company was required to inform the NRC of this reduction in commitments in its QA program description and should have sought approval prior to its implementation. As such, the licensee's actions in this area constitute a violation to 10 CFR 50.54(a).

c. Conclusion

Based on the above (1) activities specified in TS 6.5.1.7, and performed by the OSC, are activities required by the Beaver Valley's QA program to meet the criteria of Appendix B to 10 CFR 50, (2) TS 6.5.2.8.d requires that such activities be audited periodically (at least once every two years) under the cognizance of the ORC, and (3) pursuant to 10 CFR 50.54(a), the decision to discontinue audits of OSC activities after 1992 constitutes a reduction in commitments in the Beaver Valley's QA program description previously accepted by the NRC. Failure to perform audits of activities performed by the OSC under the cognizance of the ORC since 1992 constitutes a violation of the Beaver Valley TS 6.5.2.8.d, Criterion XVIII of Appendix B to 10 CFR 50, and of 10 CFR 50.54(a)(3) **(VIO 50-334(412)/96007-03)**.

II. Maintenance

M1 Conduct of Maintenance

M1.1 2-2 Emergency Diesel Generator 18 Month Overhaul

a. Inspection Scope (62707)

The inspectors observed portions of maintenance activities during the overhaul of the 2-2 Emergency Diesel Generator (EDG). The EDG experienced two unplanned overspeed trips during maintenance testing and adjustment following governor replacement. The inspectors reviewed procedures and conducted interviews with Operations, Maintenance, and Engineering personnel to assess troubleshooting and corrective maintenance activities. Overhaul activities included:

- Procedure 2MSP-36.20-M "#2 Emergency Diesel Generator Inspection," Rev. 2

- Procedure 2MSP-36.30-M "#2 Emergency Diesel Generator Filter, Strainer, Heat Exchanger,and Woodward Governor Maintenance," Rev. 4

- Procedure 2CMP-36-EDG Governor-1M "Emergency Diesel Generator Governor Replacement and Adjustment," Rev. 0

b. Observations and Findings

On September 18, 1996, upon starting the 2-2 EDG for adjustment following replacement of the mechanical governor, the engine ramped to 85 rpm for ten seconds, ramped to 300 rpm for ten seconds, then continued to increase speed until it tripped on overspeed. Governor oil level was not visible in the gauge glass when the EDG tripped. Problem report 2-96-500 was written to evaluate the cause of the overspeed event. The engine vendor and the system engineer inspected the governor, changed the oil, and mechanically stroked the governor by hand. The system engineer identified the most probable cause of the overspeed to be air in the oil lines for the governor. The EDG was then started on the mechanical governor, the low and high speed mechanical stops were set, and the overspeed trip was successfully tested.

The EDG was then started to set the electrical governor. The EDG quickly increased speed past the electrical speed setpoint and the high speed mechanical stop, and mechanically tripped on overspeed. Operations quarantined the EDG room to preserve as left conditions for follow-up evaluation. During the two overspeed trip events, the EDG engine vendor was onsite. However, governor vendor onsite assistance was not requested until after the second overspeed trip.

On September 19, the governor vendor arrived and began troubleshooting. During inspection of the overspeed trip device it was identified that the pawl in the overspeed trip was not in the correct position. The overspeed trip was disassembled for inspection and the lower assembly was replaced.

On September 20, the EDG was started, the high and low speed stops were set, and the overspeed trip was tested satisfactorily. The electric governor was adjusted and the EDG was tested satisfactorily by Operation Surveillance Test. Maintenance personnel determined the cause of the second overspeed trip was setting the governor to the high speed stop instead of the low speed stop and not properly adjusting the electric governor to mechanical governor interface. Minor vendor manual discrepancies for the overspeed trip device were identified and corrected.

The inspectors discussed the causes of the overspeed events and the corrective actions to prevent recurrence with the system engineer and maintenance personnel. The inspectors attended a meeting between station management and system engineers in which discussions identified a possible generic concern related to control of vendors. System engineers determined that the root cause of the two overspeed events was due to relying too heavily on vendor personnel knowledge in lieu of station procedures during previous EDG outages. For example, during post-trip discussions, the vendor stated that he often mechanically turns the governor by hand to remove trapped air. This information is not captured in the procedures. The governor needle valve is factory set at 1/4 turn and is accepted as correct

unless otherwise instructed. The governor vendor normally checks the position of the needle valve and adjusts it to approximately 5/8 turn. This setting would allow the governor to be slightly over-responsive and therefore would provide some margin.

Maintenance, engineering, and management personnel performed an in-depth EDG trip review and developed insightful improvements to the EDG maintenance practices. EDG maintenance procedure revisions were initiated to capture the lessons learned from the overspeed events and discussions with the vendor.

c. Conclusions

Maintenance activities on the 2-2 EDG were properly performed, with the exception of speed governor replacement post maintenance testing. The 2-2 emergency diesel generator (EDG) experienced two unplanned overspeed trips. Senior management involvement was necessary to ensure the event was properly evaluated in a timely manner. Vendor knowledge specific to the EDG governor maintenance had not been completely incorporated into station procedures. Work ownership, vendor oversight, and procedural weaknesses were identified. The post event review of unplanned 2-2 EDG overspeed trips during maintenance was thorough and developed insightful, well focused findings.

M1.2 Routine Surveillance Observations (61726)

The inspectors observed selected surveillance tests. Operational surveillance tests (OSTs) observed by the inspectors are listed below.

- 2OST 26.4 Turbine Pedestal and Emergency Trip System Test Panel Checks
- 1OST 24.2 Motor Driven Auxiliary Feed Pump Test (1FW-P-3A)

The surveillance testing was performed safely and in accordance with proper procedures. Additional observations regarding surveillance testing are discussed in the following sections. The inspectors noted that an appropriate level of supervisory attention was given to the testing, depending on its sensitivity.

M2 Maintenance and Material Condition of Facilities and Equipment (92902)

M2.1 (Closed) LER 50-334/96001: Unit 1 Main Steam Safety Valve Setpoints Found High. During pre-outage testing, the licensee identified that eight main steam safety valves were outside their setpoint by greater than the +1% allowable tolerance. Greatest offset was relief valve SV-MS-103A which was found 9.4 psi above its allowable setpoint range of 1095 psig +1%, -3%. An engineering evaluation has attributed the cause to setpoint drift and temperature effects from performing as-left and as-found testing at different temperatures/Modes. Procedural changes have been made to prevent recurrence. This LER is closed.

M2.2 (Closed) URI 50-334(412)/94007-02: Heat exchanger performance issues. Portions of this item were inspected and closed in inspections 94-14, 94-17, and 95-18. The remaining issue concerned performance of the screen wash system for the intake screens. To improve performance, the licensee has replaced a screen wash pump which enabled them to increase screen wash pressure to improve the cleaning action of the spray nozzles. Operating procedures were also improved to prevent carryover. These actions resolve the remaining issue and this item is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 Engineering Workload Management

a. Inspection Scope (37550)

The inspectors conducted interviews with plant personnel, reviewed the old engineering workload prioritization method in document NPDAP 2.17, Revision 1, "Workload Priority System" and the new method in documents "System Engineering Handbook" and "Performance Engineering Handbook."

b. Observations and Findings

The inspectors previously determined that deficiencies in the engineering workload management computer program could result in assigning a low priority to an issue of importance (see NRC IR No. 50-334[412]95021) . The reason is that descriptive information of the program, in terms of factors of importance which can be selected by the user and receive certain priority values automatically, may not appropriately characterize an issue.

The new prioritization system, which applied to engineering memorandums (EMs) only, requires the originator to enter the priority according to guidelines in Attachment 2 of NPDAP 2.4, "Engineering Memoranda," revision 4. NPDAP 2.4 was implemented in May 1996. DLC intends to expand the system to include design change packages (DCPs), technical evaluation reports (TERs), and other documents. Since the priority was assigned by the EM originator, the computer problem of unintentionally assigning a low priority number to a job of a high priority nature has been addressed.

The prioritization system is a part of the Workload Management System, which also has the function of scheduling, tracking, and managing workload. Currently, the Nuclear Engineering Department uses the Workload Management System as a pilot user. It is too early to make a conclusion on the effectiveness of the Workload Management System.

c. Conclusions

The new priority system no longer has the problem of assigning a low priority number to a high priority job. It is too early to judge prioritization effectiveness in the new Work Management System. However, some indications showed that it may be useful in reducing engineering work backlog.

E1.2 Safety Evaluations under 10 CFR 50.59

a. Inspection Scope (37550)

The inspectors conducted interviews with plant personnel, observed a 4-hour training class entitled, "Conduct of Safety Evaluations - 1996 Retraining," examined the function of the Onsite Safety Committee (OSC), and reviewed two recent OSC meeting minutes describing the disposition of all DCPs, TERs, and EMs.

b. Observations and Findings

The inspectors reviewed the OSC meeting minutes dated April 3 and 17, 1996. The minutes each contain about ten 10 CFR 50.59 safety evaluations. The inspectors found that DLC followed the procedure in NPDAP 8.18, "10 CFR 50.59 Evaluations," revision 3, in conducting all 50.59 evaluations, and all these evaluations used the evaluation worksheet from the manual to facilitate the evaluation process. The worksheet contained a well-thought-out standard procedure for performing a 50.59 safety evaluation.

DLC relies on two mechanisms for identifying issues that require 10 CFR 50.59 safety evaluations. The first is a training program designed to maintain workers' ability to identify and conduct 50.59 evaluations and the required review and approval by OSC of most issues including the 50.59 safety evaluation. DLC's training program to qualify individuals to conduct 50.59 evaluations consists of (a) initial training: an 8-hour classroom presentation followed by an 8-hour practical training session and (b) yearly refresher/update training: a 4-hour classroom presentation plus the experience of having written a 50.59 evaluation approved by OSC within that year.

The OSC serves as a second check for 50.59 evaluations. OSC members are experienced personnel from various departments who routinely reviewed technical or nontechnical issues for disposition. There was one instance this year that OSC reclassified an issue as requiring a 50.59 evaluation after the preparer and reviewer had determined otherwise. This is an example of the committee providing effective oversight of 50.59 evaluations.

c. Conclusions

Based on interviews with plant personnel and the review of pertinent plant documents, the inspectors found that the training program and the function of OSC, which formed the foundation for adequate 50.59 evaluations, are sound.

E1.3 Engineering Backlog Reduction

a. Inspection Scope (37550)

The inspectors discussed the backlog reduction team effort with Nuclear Engineering Department (NED) managers, reviewed the backlog reduction team final report, and the July 1996 NED performance indicators report.

b. Observations and findings

The number of open work items, or work backlog, has been an issue for the past several years. With a large backlog of open work items, safety significant issues could be overlooked or receive a low priority, due to sheer numbers.

In early 1996, NED managers placed a higher priority on closing out old work items which had been in the backlog for some time. In May 1996, NED initiated a Backlog Reduction Project, assigning a team of six engineers to identify those work items in the backlog which were of highest importance to the station, and reduce them to more manageable levels. The primary emphasis was on items which were listed as past their target due dates as of the end of March 1996. The program was to run until mid-August 1996, and had target dates for the accomplishment of goals related to specific types of work items in the backlog. To the extent possible, the team had the engineer originally responsible for the work item bring it to closure. Due to familiarity with the issues involved, this was deemed more suitable than having the team members perform all the closeout work. The effort achieved a reduction in total workload from 1482 items at the end of November 1995 to 1030 items at the end of July 1996. The number of engineering work items open beyond their target due dates had been reduced to 276 as of the end of July 1996, down from 512 at the end of November 1995.

During discussions with the inspectors, NED managers indicated that it was their intention to provide continuing efforts, focused on specific performance areas, to achieve further reductions in the number of open work items and improve the timeliness of responses.

c. Conclusions

The backlog reduction team effort was effective in reducing the number of old in-process engineering work items. In addition, improvement in the overall timeliness of responses was achieved.

E2 Engineering Support of Facilities and Equipment

E2.1 Unit 2 Reactor Vessel (RV) Head Boric Acid Buildup

a. Inspection Scope (37551)

Maintenance personnel identified discolored insulation, a boric acid buildup, and surface corrosion on the exterior of the RV head during planned refueling outage inspections. The inspectors interviewed engineering personnel, viewed photographs, reviewed documentation, and observed meetings to assess licensee disposition of this issue.

b. Observations and Findings

On September 5, 1996, maintenance personnel performed a boric acid inspection of the Unit 2 RV head following removal of mirror insulation. Boric acid buildup and corrosion were identified where the ventilation shroud contacts the RV head. Engineering memorandum (EM) 112802 was written to (1) Evaluate the boric acid corrosion buildup on the carbon steel RV head and (2) Determine the most likely source of the leak.

With vendor assistance, materials engineers determined that the corrosion was limited to approximately a 1 mil layer and there were no discernable pits or corrosion related gouges in the area of interest. Engineers concluded that there was no structural integrity concern for the RV head or the ventilation shroud support members.

A cobalt-58 dating process indicated that the boric acid residue was over twelve months old. The residue age combined with the limited boric acid buildup area, indicated that an active leak on the RV head was unlikely. Engineers conducted a detailed leakage assessment including ten possible leakage sources. The evaluation identified three potential sources from past activities. Their findings were presented to the NSRB. NSRB thoroughly reviewed the issue and generated good follow-up recommendations. The two most noteworthy were: (1) Consider developing a diverse method to identify RV head leakage during power operation in addition to existing seal leak detection devices and (2) Develop a process to historically document and trend observed RV head stains and indications of leakage. The inspectors observed that the RV head did not have an active leak and that NSRB discussion included a good review of industry events.

c. Conclusions

The inspectors concluded that material engineers performed an excellent assessment of the boric acid leakage and corrosion of the RV head. Vendor and industry information was effectively integrated into the evaluation.

E2.2 Unit 2 Fuel Failures

a. Inspection Scope (37551)

Unit 2 primary chemistry results indicated elevated activity levels indicative of fuel failures during the last operating cycle. The inspectors observed follow-up activities to ensure the leaking fuel pins were identified and corrected.

b. Observations and Findings

Ultrasonic testing (UT) results revealed that two fuel assemblies (H65 and H04) each had one leaking fuel pin. Each assembly was Vantage 5H type fuel and had been in the core one fuel cycle. Assembly relative power was 1.4 to 1.5. With vendor assistance the licensee reconstituted assembly H04 for reuse this fuel cycle. While removing the damage fuel pin from assembly H65, the top 30 inch section of the fuel pin broke off. Appropriate radiological area and airborne surveys were performed and indicated no abnormal radiological conditions.

Fueling engineers quarantined assembly H65 and selected an alternate assembly for core reload. Core analysis was re-performed for the alternate assembly and reload was successfully completed. Engineers continued to work closely with the fuel vendor to determine the cause of the failed fuel pins and to develop a plan to reconstitute assembly H65.

c. Conclusions

The inspectors determined that engineers effectively identified two leaking fuel pins and responded appropriately to a broken fuel pin during fuel assembly reconstitution.

E3 Engineering Procedures and Documentation

E3.1 System Engineer Handbook

a. Inspection Scope (37550)

The inspectors reviewed the newly created System Engineer Handbook to evaluate the guidance it provides to Systems and Performance Engineering Department (SPED) personnel.

b. Observations and Findings

The System Engineer Handbook was created to provide management expectations to system engineers regarding conduct of their assigned activities. The handbook contains, as attachments, the System Engineer Responsibilities (Manifesto), the Nuclear Power Division Business Plan, Beaver Valley 1995 Top Ten List Status, Beaver Valley Power Station Site Standards, and other documents which describe the expectations.

The manual was intended as a supplement to, not a replacement for, the procedural guidance located in the Maintenance Program Unit Administrative Procedures (MPUAP). For example, in several instances (such as the timing of system walkdowns) the handbook uses "should" indicating a preference, where the procedures use "shall" or "will" to describe the same activity, denoting a specific requirement. The handbook gives broad, general guidance for conducting activities. The MPUAPs provide detailed, step by step instructions.

c. Conclusions

The System Engineer Handbook is an excellent initiative in that it assembles, in one place, broad general guidance on the conduct of system engineer activities and management expectations related to personnel performance. Detailed step by step instructions are provided in the MPUAPs.

E3.2 Performance Engineer Handbook

a. Inspection Scope (37550)

The inspectors reviewed the newly created Performance Engineer Handbook to evaluate the guidance it provides to Maintenance Support Engineering personnel.

b. Observations and Findings

The Performance Engineer Handbook is a companion document to the System Engineer Handbook. It was written to address those activities conducted by performance engineers and program engineers assigned to Maintenance Support Engineering. It serves as a supplement to the procedural guidance in the MPUAPs as well. The handbook's attachments provide explicit statements of management expectations for personnel performance.

c. Conclusions

The Performance Engineer Handbook is an excellent initiative in that it incorporates both management's expectations and general guidance for personnel performance. Detailed instructions for performing specific work activities are again located in the MPUAPs.

E3.3 Procedural Guidance for System and Performance Engineers

a. Inspection Scope (37550)

The inspectors reviewed Section 8.0 of the Maintenance Programs Unit Administrative Manual (MPUAM) to determine the procedural requirements for the activities conducted by system engineers and performance engineers. In addition, the inspectors discussed the procedures with SPED managers to determine how the recent reorganization will affect the procedures. While all of the procedures received a cursory review, the inspectors reviewed the following procedures in detail:

- MPUAP 8.1.1, "MEAD Personnel Training and Certification," Rev. 0
- MPUAP 8.1.2, "BVT Procedure Preparation and Revision," Rev. 0
- MPUAP 8.1.3, "Administrative Guidelines for Performing Tests, Test Result Reports, and Test Records," Rev. 0

b. Observations and Findings

Section 8.0 of the MPUAM contains the procedures which governed MEAD activities. These procedures now govern SPED and maintenance support engineering activities. Requirements are established for the training and qualification of engineering support personnel (ESP), generation of procedures, conduct of testing, performance of plant and system monitoring activities, and special programs. Examples of special programs include welding, MOVs, equipment qualification, lubricant monitoring and control, ASME repair/replacement, and control of halogenated hydrocarbons.

The procedures established clear requirements to be met, objective and measurable criteria for verification, and assigned responsibilities for ensuring compliance with the requirements. In addition, duties and responsibilities of the positions within the organization were delineated, along with the authorities related to the positions. The procedures provided clear step by step instructions for completing the activities performed by the system, program, and performance engineers.

During discussions with SPED personnel, the inspectors determined that the future of the MEAD MPUAPs is not clearly defined. While it is recognized that MEAD no longer exists as an entity, no definite plans existed relating to the MEAD MPUAPs. The procedures remain in use in their current form.

c. Conclusions

The MPUAPs provided a good structural base for the system engineering program and functions. Requirements were clearly defined, as were the means of verifying compliance. The inspectors concluded that the lack of clear preplanning for converting the MEAD MPUAPs was not a significant issue since it has no effect on the quality of the procedural guidance provided.

E6 Engineering Organization and Administration

E6.1 Reorganization of System Engineering Function

a. Inspection Scope (37550)

The inspectors conducted interviews with plant personnel, and reviewed organization charts and written guidance on the functions of the system and component engineers.

b. Observations and Findings

The system engineering function was formerly assigned to the Maintenance Engineering and Assessment Department (MEAD) in the Maintenance Programs Unit (MPU). It now resides in the newly created Systems and Performance Engineering Department (SPED), under the Vice President of Nuclear Services. The modification testing, component engineering and program engineering functions, formerly part of MEAD, now reside in Maintenance Support Engineering, under the Maintenance Group in the MPU. The reorganization was announced by memorandum dated May 8, 1996. System assignments under the new organization were promulgated by memorandum dated July 2, 1996.

Prior to the reorganization taking effect, meetings were held with plant personnel in engineering, operations, and maintenance to describe the new organization, and the performance improvements it was intended to achieve. In addition, the memorandum assigning system responsibilities was widely distributed to plant staff. The training included guidance on the process on obtaining information and assistance from the new organization. Discussions with maintenance personnel indicated that this was helpful in determining the responsible engineer when assistance is needed.

With the reorganization, additional personnel were assigned as system engineers, and the system assignments were redistributed to even out the workload between work groups. To the extent possible, each system has been assigned a primary engineer and a backup engineer. The primary system engineer is responsible for tracking and trending system performance, resolving system problems which do not involve design or licensing basis issues, performing routine surveillances conducted under Beaver Valley test procedures (BVTs), and remaining generally aware of system status. When system engineers receive design or licensing basis issues from the plant, they generate engineering memoranda (EMs) to request resolution from design engineers. Backup engineers perform the duties of the primary engineer in his or her absence. At the time of the inspection, some of the "new" system engineers were still filling their former positions. They will transition to their new positions as soon as their replacements are identified and trained.

c. Conclusions

The reorganization of the system engineering function out of MPU and into SPED was intended to provide more emphasis on improving system performance and to develop "technical experts" for the plant systems. Given that at the time of the inspection the new organization was not yet complete, evaluation of the results of the reorganization at this time would be premature.

E8 Miscellaneous Engineering Issues (90712, 92700)

E8.1 (Closed) URI 50-334/94020-01: Engineers prepared a safety evaluation in 1994 to determine if excavating buried Unit 1 river water lines involved an unreviewed safety question. These lines were replaced and then reburied. The inspectors reviewed the methodology used in the safety evaluation, particularly with respect to the use of probability to demonstrate protection from tornado generated missiles while the lines were exposed.

NRC Standard Review Plan (SRP) 3.5.1.4 states that all plants should "be designed to protect safety-related equipment against damage from missiles which might be generated by the design basis tornado for that plant". While the SRP provides guidance for assessing the need for protection of structures, system, and components from missiles generated by other natural phenomena (i.e., other than tornado) based on probability of damage, this criteria is not applicable to tornado missiles.

UFSAR 2.7.5 states that the river water lines that run between the intake structure and the auxiliary building are buried a minimum of six feet below grade to provide protection from tornado missile hazards. Therefore, absent a change to the BVPS-1 licensing basis, physical design features and/or protective barriers must be used to protect the river water lines from tornado generated missiles. 10 CFR 50.59 states in part that a proposed change involved an USQ "if the probability of occurrence ... of an accident or malfunction of equipment important to safety previously evaluated in the safety analysis report may be increased ...," and the licensee's safety evaluation had identified that this activity did result in an increase in the probability of equipment failure.

The licensee's safety evaluation did not provide an acceptable bases for a determination that the change does not involve an unreviewed safety question and is a violation of 10 CFR Part 50.59. As discussed in NRC IR No. 50-334/94-20, NRC did not have a safety concern with the excavation of the river water lines. The licensee has committed not to use probability arguments to demonstrate protection from tornado generated missiles without requesting exemption from the applicable General Design Criteria from NRC. This violation was of minor consequence and is being treated as a Non-Cited Violation consistent with Section IV of the NRC Enforcement Policy **(NCV 50-334/96007-04)**.

E8.2 (Closed) URI 50-412/96006-02: Fire Pump Capacity Issue

a. Inspection Scope

DLC audit personnel identified that the fire pumps may not be individually capable of supplying the largest load on the system, the Unit 2 Turbine Building sprinkler system.

The inspectors reviewed design calculations performed by the original installer, and current calculations performed by DLC to evaluate the capacities of the sprinklers, pumps, and fire mains. Specific documents reviewed included:

- ANI Letter 88-149-17, dated June 9, 1988
- ASCOA Calculation HO11.A02, "Beaver Valley Power #2 Turbine Bldg. El. 774-6, Remote 10,000 sq. ft. @.20 gpm/sq.ft.," dated May 19, 1988
- DLC Calculation 8700-DMC-3079, "Fire Pump Minimum Operating Curve," Rev. 0
- DLC Calculation 10080-B-436, "Sprinkler Supply Requirement for BVPS-2 Turbine Building Under Operating Floor Most Remote 10,000 sq. ft. Area 0.2 gpm/sq. ft. Coverage," Rev. 0
- DLC Calculation 10080-B-438, "Turbine Building Under Operating Floor Sprinkler System Conformance with NFPA-850," Rev. 0
- Quality Services Deficiency Report QSAS-95-0104
- Quality Services Deficiency Report QSAS-96-0081
- BVPS EM 110728, "FP Pump System Operating Requirements"
- NFPA 13, "Installation of Sprinkler Systems," 1976 Edition
- NFPA 850, "Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations," 1996 Edition

b. Observations and Findings

The original design of the system conformed to American Nuclear Insurers (ANI) specifications for sprinkler systems since neither the National Fire Protection Association (NFPA) nor any other governing body had specifications for sprinkler systems in power plants. At the time, the ANI specification had dual criteria: 0.3 gallons per minute (gpm) per square foot (ft^2) for the most remote 3000 ft^2, and 0.2 gpm/ft^2 for the most remote 10,000 ft^2. These were the original design inputs for the sprinkler system, and were used in the 1983 sprinkler system design calculations.

During walkdowns of the field installation of the sprinkler systems, circa 1987-88, a representative of ANI requested that more sprinkler heads be installed in the under operating floor sprinkler network due to perceived inadequacies in coverage. In May 1988, after the requested sprinkler heads were added, the installer, Automatic Sprinkler Company of America (ASCOA), recalculated the flows and pressures in the network. The new calculation showed a flow value of just over 0.36 gpm/ft^2 for the most remote 10,000 ft^2, or a total flow just over 3600 gpm. This flow exceeded the rated capacity of a single fire pump, but was within the 150% rating of the pumps. It does not appear that this higher flow was carried back to evaluate the capability of the yard fire main loop to supply the necessary pressure at that flow. DLC received agreement from ANI that operation of two fire pumps to meet the sprinkler demand plus two hydrants was acceptable.

NFPA issued NFPA 850, "Recommended Practice for Fire Protection for Fossil Fueled Steam Electric Generating Plants," in 1986. This was the first sprinkler

specification written specifically for power plants. The scope of the specification was subsequently expanded to include combustion turbine generating stations, alternative fuel generating stations, and high voltage DC convertor stations. The most recent edition, with an effective February 2, 1996, includes in Section 5-7.4.1, the requirements for turbine generator areas. This requirement states, in part, "All areas beneath the turbine operating floor that are subject to oil flow, oil spray, or oil accumulation should be protected by an automatic sprinkler or foam-water sprinkler system. ... The sprinkler system beneath the turbine generator ... should be designed to a density of 0.30 gpm/ft^2 over a minimum application of 5,000 ft^2."

DLC Calculation 10080-B-438 used the 1988 ASCOA calculation as a starting point and the Unit 2 turbine building under operating floor sprinkler network was modeled to match the 1988 calculated flows. Several different 5,000 ft^2 areas were selected and modeled by designating the sprinkler heads which are assumed to be flowing. The most remote 5,000 ft^2 was then selected by comparing flows and pressures at the hydraulically most remote sprinkler head. The calculation verified that adequate pressure and flow are available to the most remote head with an additional 1,000 gpm flow from hydrants and only one fire pump in operation.

c. Conclusions

With the addition of sprinkler heads to the Unit 2 turbine building under operating floor sprinkler network in the 1987-88 time frame, at the behest of the casualty insurance provider, the system design was modified. Inadequate controls were applied to the design change in that the additional flow was not accounted for in the calculation of turbine building riser supply pressure. This eight year old failure to control design changes was licensee-identified and corrected, and is being treated as a Non-Cited Violation consistent with Section VII.B.1 of the NRC Enforcement Policy (**NCV 50-412/96007-05**).

E8.3 (Update) URI 50-334/96006-01 and (Closed) URI 50-412/96006-01: Containment Penetration Overpressure Protection

a. Inspection Scope

The inspectors observed activities relating to the evaluation of containment penetration thermal expansion issues, discussed the activities with DLC personnel, and reviewed design documents issued to rectify identified problems. Specific documents reviewed included:

- Problem Report 1-96-506
- Problem Report 1-96-584
- Problem Report 1-96-585
- Basis for Continued Operation (BCO) 1-96-003
- BCO 1-96-005
- Memorandum ND1NSM:7436, Unit 1 Containment Penetration Overpressure Protection, dated July 3, 1996

- Memorandum from T. Dometrovich to D. Weakland, Piping Over-Pressurization, dated June 28, 1996
- Temporary Modification 1-96-020, dated August 1, 1996
- Equipment Clearance Permit #659505
- Design Change Package (DCP) 2204
- DCP 2205
- Technical Evaluation Report (TER) 10572, Rev. 0
- BVPS1 UFSAR, Section 5.3.3
- BVPS2 UFSAR, Section 6.2.4
- Night Orders for August 13, 1996
- IE Bulletin 79-14, dated July 2, 1979
- IE Bulletin 79-14, Rev. 1, dated July 18, 1979
- Letter from ASME Technical Inquiry Committee to Toledo Edison Company, dated October 24, 1995

b. Observations and Findings

During troubleshooting of a reactor plant component cooling water system (CCR) motor operated valve (MOV) which failed its routine testing, DLC personnel identified that the containment penetration for which the valve provided isolation was pressurized above normal operating pressure. Subsequent evaluation by NED determined that this penetration was subject to pressure excursions due to the thermal expansion of water trapped between the normally closed containment isolation valves. NED determined that, in the event of a design basis Loss of Coolant Accident (LOCA), the water trapped between the closed isolation valves could raise pressure to levels above the piping design pressure, and that overpressure protection was not provided in the original design of the penetration or piping. DLC put together a multi-disciplinary team, composed of personnel from NED, Operations, SPED, Nuclear Safety, Chemistry, and Operations Procedures, to evaluate and recommend corrective actions.

NED performed an evaluation of penetration pressurization for all containment penetrations in Unit 1 and Unit 2. NED confirmed that the problem of thermal expansion causing penetration overpressurization was an issue only for Unit 1. Many of the penetrations on Unit 2 had relief valves installed during original design and construction. The Unit 1 penetrations were further evaluated for design pressure, code allowable stresses, isolation valve pressure capability, pressure relief modes of isolation valves (such as check valves and air-operated trip valves), and as-built piping configuration.

Sixteen penetrations were identified for actions to mitigate pressure buildup. These actions included opening inboard isolation valves to allow system relief valves to provide protection, isolating and draining the penetration (along with plans to ensure the penetration does not refill over time), or opening the inboard isolation valve and a system vent or drain valve. A further review was performed by DLC's multi-disciplinary team to determine if any of these valves were identified for operation in the EOPs, alarm response procedures (ARPs), or off-normal operating procedures. The positions of the valves are being administratively controlled through use of the

facility tagging system (equipment clearance permits). A number of penetrations with air-operated trip valves were considered by NED to be acceptable for the near term, due to pressure under the valve disc opening it against spring force to relieve pressure at levels below code allowable stresses. NED did not consider relief paths through outboard containment isolation valves acceptable as this could lead to containment bypass paths.

Nine penetrations were identified as needing to have relief valves installed in the near term (prior to plant startup). Other penetrations with relief paths through isolation valves, which have been isolated and drained, or are otherwise being administratively controlled, will be evaluated for the addition of relief valves during a future outage to limit piping pressure to below design pressure.

For a number of the sampling lines which penetrate containment, NED determined that the pressures needed to lift the trip valve disc off its seat exceeded the code allowable stress levels for the penetration. For these lines, the caps were removed from the leakage monitoring system connection points inside the containment, and the outboard isolation valves were "failed" shut with air removed and tagged from the trip valve actuators. This action adversely restricts the ability to sample the safety injection accumulators, RHR system, and the pressurizer vapor space, but will maintain containment integrity.

As part of the evaluation of the containment penetrations in Unit 1, DLC performed walkdowns of the piping and penetrations and verifications of the as-built piping drawings. During the walkdowns, DLC identified that piping for several penetrations was not as shown on the drawings. These penetrations were all small-bore piping (2 in. and under), for which supports were built to generic standards during original construction. Originally, small-bore piping supports were neither individually analyzed, nor were the small-bore isometrics reviewed and revised for as-built configurations. NED evaluated the as-built configuration and determined that three penetrations needed upgrading to meet seismic criteria at the increased pressures. IE Bulletin 79-14, "Seismic Analyses for As-Built Safety-Related Piping Systems," issued July 2, 1979, required that seismic analyses for safety-related piping systems be conducted based upon as-built configurations. Revision 1 to IE Bulletin 79-14, issued July 18, 1979, limited the scope of as-built analyses to piping 2-1/2 inches in diameter and larger.

At the time of the inspection, NED was generating containment penetration overpressurization design basis documents. There will be separate documents for Unit 1 and Unit 2. The emphasis was on completing the Unit 1 document with that for Unit 2 to follow. These documents will be controlled, and updated if any changes are made during the evaluation of the long-term acceptability of pressure relief means for containment penetrations.

c. Conclusions

When the excessive pressure in the CCR penetration was identified during MOV troubleshooting, the response of DLC was excellent. As a result of the NED determination that in-containment temperatures from a LOCA could result in the penetration exceeding its design pressure, a multi-disciplinary team was assembled to review the occurrence, determine the scope of the problem, and develop corrective actions. NED personnel researched the original designs and code requirements for both units, evaluated all Unit 1 penetrations which did not have relief valves installed, and developed action plans to limit pressures for those penetrations which could be overpressurized by thermal expansion of trapped water.

Due to the problem not pertaining to Unit 2, this item is closed for Unit 2. This item remains unresolved for Unit 1.

E8.4 (Closed) LER 50-334/93004 and (Closed) LER 50-412/93005)

The inspectors reviewed the long-term corrective actions for Unit 1 LER 93-04 involving a potential post small break loss of coolant accident release path and Unit 2 LER 93-05 involving the potential for a failure of a motor operated valve to result in inadequate recirculation flow after transferring from cold leg to hot leg injection.

The issue reported in Unit 1 LER 93-04 was previously inspected as documented in NRC IR No. 50-334/93-01. The inspectors verified that the licensee completed Unit 1 Design Change Package (DCP) 1985, Unit 2 DCP 2001, and included the reactor coolant pump seal water heat exchanger relief valves in the inservice test program. These changes raised the design pressure of the seal water heat exchangers and piping and the set point of the seal water heat exchangers relief valves above the shutoff head of the low head safety injection pumps thus isolating the release path. These actions completed the long-term corrective actions for this LER. This LER is closed.

The issue reported in Unit 2 LER 93-05 was previously inspected as documented in NRC IR Nos. 50-412/93-22 and 93-23. The inspectors verified that the licensee completed the long-term corrective actions of revising the Emergency Operating Procedures to verify recirculation flow and restore it if necessary. This completes the long-term corrective actions for this LER. This LER is closed.

E8.5 UFSAR Review

a. Inspection Scope

The inspectors reviewed BVPS1 UFSAR Section 5.3.3 and BVPS2 UFSAR Section 6.2.4 regarding containment penetration overpressure protection. In addition, the inspectors reviewed an ASME Technical Inquiry Committee letter to Toledo Edison company dated October 24, 1995.

b. Observations and Findings

The UFSAR for each unit lists the containment penetrations which have overpressure protection. Those penetrations listed as having overpressure protection in the UFSARs do indeed have relief valves installed. The UFSARs state that the penetrations have been evaluated for potential overpressure conditions, and those "few" penetrations which need protection have it. The ASME Code does not require overpressure protection for those portions of a piping system (consisting of piping and isolation valves) which are out of service and perform no required function.

c. Conclusions

The configurations of the containment penetrations for Units 1 and 2 are as described in the UFSAR. The penetrations meet the requirements of the ASME code.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Refueling Outage Radiation Protection (RP) at Unit 2

a. Inspection Scope (83750)

The inspectors reviewed radiological controls implemented in the Unit 2 refueling outage (6R) and problem reports relating to radiation protection (RP). The inspectors reviewed steam generator work, refueling floor work, RP-related activities concerning a fuel pin that failed during fuel bundle reconstitution, and other minor work activities. The inspectors made frequent tours of the radiologically-controlled areas (RCAs) and interviewed RP supervision and several RP technicians. This inspection included tours conducted during backshift hours.

b. Observations and Findings

At the time of the inspection, steam generator (S/G) work was progressing well from the standpoint that workers exposures were being kept as low as is reasonably achievable (ALARA). Work was being conducted in accordance with established ALARA plans. The licensee was effectively managing this work through preplanning, briefings, shielding, extensive RP technician and supervision oversight, robotics, remote manual tooling, remote observation, and remote radiation monitoring equipment. RP control points were established just outside the steam generator cubicles. External exposure controls for S/G work were excellent.

No RP concerns from the fuel pin failure were noted by the inspectors. At the time of the inspection, fuel pool radiation surveys and air samples had not identified transuranics or other hard-to-detect radionuclides, such as pure beta emitters.

The inspectors made the following general observations during the course of the inspection.

- No contamination control inadequacies were noted (other than isolated poor radiation worker practices).
- There were no hot particle contamination events of regulatory concern.
- Tracking of "clean area" personnel contamination events (PCEs) improved.
- Postings and labels were generally established in accordance with the established program.
- Individuals were wearing the required dosimeters.
- When challenged by the inspectors, workers were aware of the dose rates in their work locations.
- Unit 2 ALARA performance to date was good.
- ALARA personnel were satisfied with the performance and cooperation given by in-service inspection, operations, and engineering personnel.
- ALARA briefings attended by the inspectors were well-focused.
- No ALARA review implementation discrepancies were noted by the inspectors.
- The inspectors noted that RP technicians were very attentive and effectively challenged individuals entering HRAs.

c. Conclusions

Implementation of radiological controls in the Unit 2 refueling outage was characterized by good application of planning and controls for work in radiologically-controlled areas (RCAs).

R1.2 Station ALARA Performance for 1996

a. Inspection Scope (83750)

The inspectors followed-up on the Unit 1 refueling outage ALARA performance, which was previously reviewed and documented in NRC Inspection Report 50-334/96-04. The inspectors reviewed documentation and discussed the Unit 1 refueling outage performance with RP supervision and ALARA specialists.

b. Observations and Findings

The station ALARA goal for 1996 was set at 417 person-rem for both units. The Unit 1 and Unit 2 refueling outage ALARA goals were set at 235 and 140 person-rem, respectively. Unit 1 refueling outage performance was good with about 260 person-rem expended. The primary factors that caused the goal to be exceeded were that: (1) about 26 person-rem were expended for tasks of expanded work scope or emergent work, and (2) about nine person-rem was expended unexpectedly on steam generator (S/G) bowl cleanup because the vendor's equipment poorly captured the S/G tube plugging material during S/G tube recovery activities. Other observations regarding the ALARA program are contained in Sections R1.1 and R7 of this report.

c. Conclusions

Overall, the ALARA program was well implemented.

R1.3 Radioactive Waste Management

a. Inspection Scope (86750)

The inspectors reviewed licensee efforts in managing radioactive waste. The inspectors made frequent tours of the RCAs, interviewed the responsible supervisor for radioactive waste management oversight, and reviewed documentation.

b. Observations and Findings

It was noted, to the inspectors, that current waste generation levels were on-target with the established goal. At day 20 of the refueling outage (roughly midway of schedule), only about 2,000 ft^3 of waste had been generated. This is 30% of the established radioactive waste volume goal. Of the 2,000 ft^3, 1,550 ft^3 was dry active waste (DAW, 38% of goal), 300 ft^3 was "green is clean" waste (14% of goal), and 180 ft^3 was spent resin (50% of goal).

One key change noted to the inspectors was that the Health Physics (HP) Department effected better oversight and decision-making over resin replacement by trending demineralizer decontamination factors. Through better trending, the HP Department had improved their radioactive waste generation program by ensuring that a resin bed is essentially depleted prior to replacement, thereby minimizing radioactive waste generation.

c. Conclusions

Efforts to control and minimize radioactive waste generation appeared to be successful. The trending analysis of resins used for water conditioning and processing was an effective initiative to control waste generation.

R2 Status of RP&C Facilities and Equipment

a. Inspection Scope (83750)

The inspectors interviewed RP personnel, observed operation of the RCA access control system during the course of the inspection, and observed the flow of personnel through the Unit 2 RCA RP control point.

The inspectors toured the Unit 2 Reactor Containment Building (RCB) and reviewed high radiation area (HRA) access controls. The inspectors conducted tours and surveys, and discussed controls with RP supervision.

b. Observations and Findings

The inspectors noted that the Unit 2 RCA control point was not congested as it had been in previous outages and as a result it was much easier for RP staff to monitor and assist workers as they entered or left the Unit 2 RCA. Access to the Unit 2 RCA was controlled through separately-established ingress and egress points. A portal monitor was stationed at the Unit 2 RCA control point and helped to minimize congestion in this area.

All individuals entering the RCA were provided with an electronic dosimeter and signed onto a computer-based radiation work permit (RWP). Workers were able to monitor their accumulated exposure and area dose rate. Workers could change to a different radiation work permit or task in the field without returning to the RCA RP control point. No breakdown in RCA access controls was noted during periods of high personnel flow through the RCA RP control point, such as the initial morning entries and lunch break. RP Assistants were stationed at the RWP sign in/out desk to ensure that workers made proper entries and that the electronic dosimeters had been properly reset.

The Unit 2 RCB egress/ingress point was spacious with separate ingress and egress points. Several PCM-1s and friskers were stationed at the egress points. The licensee also stationed junior RP technicians to frisk items as workers left the Unit 2 RCB.

The inspectors were informed by the radiation protection manager (RPM) that the HRA access control fencing on the 692' elevation of the RCB was permanent. The inspectors considered this to be a good initiative on the part of the licensee and indicative of engineering support to ALARA and HRA control initiatives.

No inadequacies in the establishment of HRAs were noted. The licensee had initiated generic changes to HRA access controls to assist workers in complying with HRA controls For example:

- The RPM noted to the inspectors that the use of rope would no longer be considered to be an acceptable means of barricading the entrance to an HRA, as long as another method such as an air curtain or swing gate was practical for the area in question.

- The RPM noted that the RADDOS access control system was being used to lock out individuals from electronically signing onto a specific RWPs if they had not attended the ALARA briefing for that RWP. Control of the RADDOS electronic access control system resided with RP personnel. It was also noted to the inspectors that RWPs were more specific if they required HRA entries to conduct the associated work.

c. Conclusions

RP-related facilities and equipment were well maintained and established to support outage activities. No degradation of the RP program was noted as a result of any facilities or equipment changes.

R5 Staff Training and Qualification in RP&C

The inspectors reviewed contractor RP technician resumes and observed on-going work to determine the breadth and appropriateness of contractor RP technician qualifications for the tasks for which they had been assigned. The inspectors noted that the contractor RP staff were well-qualified; experienced; well-supervised; and, in many cases, assigned to provide coverage to tasks that they had covered during other refueling outages. The inspectors concluded that the outage RP organization was augmented with appropriately-qualified staff.

R6 RP&C Organization and Administration

a. Inspection Scope (83750)

The inspectors reviewed the RP outage organization to determine whether staffing was sufficient to maintain occupational radiation protection safety in a period of stress on the RP organization. The inspectors interviewed station personnel and observed work activities.

b. Observations and Findings

The RPM noted to the inspectors that the RP organization was augmented by 78 senior and 13 junior contractor technicians for outage support. The inspectors observed that RP supervision spent considerable time in the field. RP functions such as dosimeter issuance and whole body counting were generally staffed for continuous outage support. RP field operations technicians were assigned to areas of Unit 2 to provide more dedicated coverage. The inspectors assessed that there were no areas of the Unit 2 RCAs where RP technicians were overly burdened.

c. Conclusions

The outage RP organization was well staffed to meet the outage workload.

R7 Quality Assurance in RP&C Activities

a. Inspection Scope (83750)

The inspectors reviewed ongoing licensee oversight of the radiation protection program. An audit was being conducted at the time of the inspection. The inspectors discussed how the audit was progressing with the audit team leader. The inspectors also reviewed surveillances and deficiency reports from 1996 that pertained to the radiation protection program.

b. Observations and Findings

The audit team leader was being assisted by an individual with experience in radiation protection from another nuclear power station. This was considered to be an audit program strength. The licensee audit team leader had noted: (1) an improvement in radiation worker practices as compared to the Unit 1 refueling outage, and (2) no significant discrepancies at the time of the inspection.

The inspectors reviewed deficiency reports, which had been issued during the on-going audit. Of the reports reviewed, none noted any problems of regulatory significance. One deficiency report noted that other site departments (System and Performance Engineering, Operations, and Training) had provided inadequate support of the Nuclear ALARA Review Committee (NARC) in that representatives of these departments had not attended NARC meetings as expected.

The inspectors noted that surveillances were well targeted to problem areas or matters of high challenge to the RP organization.

c. Conclusions

Quality assurance in RP activities was assessed as being very good.

R8 Miscellaneous RP&C Issues

R8.1 UFSAR Review

a. Inspection Scope (83750)

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedure and/or parameter to the UFSAR descriptions.

b. Observations and Findings

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that observed plant practices, procedures, and parameters were consistent with the UFSAR descriptions.

c. Conclusions

UFSAR related aspects of RP&C activities inspected were consistent with UFSAR discrepancies.

R8.2 Problem Report 196-676 Improper High Radiation Area Entry

a. Inspection Scope (83750)

The inspectors reviewed licensee actions regarding an improper HRA entry to determine the effectiveness of licensee corrective actions.

b. Observations and Findings

On August 6, 1996, an individual assigned to support the Unit 1 unplanned outage made an entry to Reactor Containment Building (RCB) 738' "C" reactor coolant pump motor cubicle, an area controlled as an HRA, without fulfilling all HRA entry requirements.

This matter was licensee identified. Though not considered as willful, significant disciplinary actions were imposed on the individual responsible for making the improper HRA entry. The licensee described this event in meetings and station memoranda to help prevent other individuals from making the same mistake. Corrective actions also included the addition of flashing red lights to further assist workers in properly implementing requirements to enter an HRA. The inspectors did not consider this matter to be a programmatic breakdown of HRA controls. HRA controls were properly established, but not adhered to in this case.

c. Conclusions

This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy **(NCV 50-334/96007-06)**.

R8.3 General Area Tours (71750, 92904)

The inspectors conducted plant tours to determine whether appropriate radiological controls and personnel safety measures were in place. In general, radiological postings were complete and in good condition. However the inspectors observed isolated examples of radiological control and housekeeping discrepancies which indicated a need for increased attention to detail during routine area tours. Specific

observations included significant water accumulation in a radiological catch containment at the Unit 1 quench spray pump 1B, incomplete deposting of a radiological area in the Unit 1 safeguards area, and missing confined space postings for the service water bays in the intake structure. The inspectors discussed these observations with the shift supervisor and the responsible discipline managers. Appropriate corrective actions were implemented.

S3 Security and Safeguards Procedures and Documentation

S3.1 Loss of Accountability of Safeguards Material

a. Inspection Scope (71750, 92904)

Inspectors reviewed DLC's investigation and subsequent corrective actions resulting from the discovery during an audit that several safeguards documents were missing from the Maintenance Department storage location.

b. Observations and Findings

On August 28, while performing an annual audit of the Instrumentation and Controls (I&C) Section safeguards files, the safeguards custodian identified three drawings unaccounted for. The custodian informed the I&C supervisor, who informed the Nuclear Security Department. One of the three documents was subsequently located. Following initial evaluation of the issue by DLC, the NRC was notified in accordance with 10 CFR 73.71. The Nuclear Security Department initiated an investigation including an audit and inventory of all I&C safeguards files, personnel interviews, and searches of shops and work stations.

During the audit and investigation, six additional drawings were unaccounted for, one of which was subsequently located in an authorized storage location. Additionally, auditors discovered several safeguards drawings that were not protected in accordance with the site procedures. These documents included wiring lists and construction drawings. DLC also identified that the combination to a storage cabinet for I&C safeguards documents had not been adequately controlled. In total, seven documents were determined to be missing. Auditors resolved eighty other administrative discrepancies, such as safeguards documents that had been downgraded but were still controlled as safeguards information, and documents that were logged as received by I&C that had never been transmitted from the originator. All discrepancies were confined to the I&C Section safeguards files. No discrepancies were noted in the other safeguards storage locations on site. Inspectors also noted that an annual inventory of safeguards information had not been done in 1995, as required by DLC administrative procedure.

Inspectors reviewed the personnel interviews, examined the safeguards storage locations, and discussed the issue with Security and I&C staff. DLC concluded that the root cause of the event was inadequate enforcement of safeguards control standards and policies by Maintenance Department management. Based on

interviews and review of material conditions, it was evident that lax control of safeguards information had existed for several years in the I&C Section.

10 CFR 73.21 requires that, "Each Licensee...shall ensure that Safeguards Information is protected against unauthorized disclosure." The Beaver Valley Power Station Physical Security Plan, section 13.7, requires that, "a system shall be established and maintained for the protection of Safeguards Information." These requirements were implemented by Nuclear Power Division Administrative Procedure (NPDAP) 2.8, "Protection of Safeguards Information." The requirements of NPDAP 2.8 include the following:

(1) Safeguards Information Custodians are responsible for the protection of Safeguards Information within their department.
(2) Personnel who handle or use Safeguards Information are responsible for protecting the information as required by 10 CFR 73.21 and this procedure.
(3) Personnel who possess Safeguards Information shall control the information while it is in use so that only persons who have a need-to-know are permitted access to the information.
(4) Department Managers shall develop a method to inventory their Section's Safeguards Information at a minimum of annually.

Nuclear Security Department reviewed copies of the missing drawings and performed inspections to verify that there were no compromises to security areas, systems, or components. They also evaluated the potentially compromised information and determined that the documents could not have allowed unauthorized or undetected access to protected or vital areas. Additional corrective actions included the following:

(1) Lock combinations were changed at all safeguards information (SI) storage locations.
(2) A comprehensive inventory of all site SI files was completed.
(3) The number of SI storage locations on site was reduced to two in order to centralize control. All SI material was removed from the control of I&C Section.
(4) The number of SI custodians was reduced and custodians were provided with management expectations and training on this event.
(5) Additional employee training is planned by October 31 on the event and enhancements to the site procedures regarding control of SI material are planned to be completed by December 31.
(6) Appropriate personnel action was taken.
(7) Maintenance Department management and supervisory personnel were counseled and performance expectations regarding control of SI were reinforced by Corporate Management.

Inspectors reviewed the missing SI documents and discussed the safety significance and compensatory measures with Security staff. Although classified as safeguards information, the drawings did not provide sufficient information to assist an individual in gaining undetected or unauthorized access due to the physical protection and electronic detection systems currently in place. Inspectors

concluded that the safety consequences of the missing drawings were minimal, and that DLC had taken adequate corrective actions.

c. Conclusions

The root cause of the event was inadequate enforcement of safeguards control standards and policies by Maintenance Department management. Based on interviews and review of material conditions, it was evident that lax control of safeguards information had existed for several years in the I&C Section. DLC took appropriate corrective actions.

The failure to adequately control safeguards information and the failure to conduct an annual inventory constitute a violation of the Beaver Valley Power Station Physical Security Plan, section 13.7 (**VIO 50-334(412)96007-07**).

S8 Miscellaneous Security and Safeguards Issues (92700)

S8.1 (Closed) LER 50-334(412)/96S03: Unaccounted for Safeguards Information. The event was reviewed in section S3.1.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on October 9, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X2 Pre-Decisional Enforcement Conference Summary

A predecisional enforcement conference was held with Duquesne Light Company management on August 28 at the Region I office. The meeting was to discuss the inability of the Unit 1 Anticipated Transient Without Scram (ATWS) Mitigating System Actuation Circuitry (AMSAC) to function if it had been required during the May 31 reactor trip. The issue was documented in NRC Inspection Report 50-334 and 412/96-05. The meeting was closed to the public. Copies of the slides used by DLC at the meeting are included as an attachment to this report.

X3 Management Meetings and Other NRC Activities

On September 19, 1996, Mr. Richard Crlenjak, NRC Region I Deputy Director (Acting), Division of Reactor Projects (DRP), met with the resident inspector staff, toured the station, and met with licensee management to discuss current licensee performance.

On October 1-2, 1996, Mr. John Stolz, NRC NRR Director, Project Directorate I-2, and Mr. Don Brinkman, NRC NRR Project Manager for Beaver Valley Power Station, met with the resident inspector staff, toured the station, and met with licensee management to discuss current licensee performance.

ATTACHMENT

PARTIAL LIST OF PERSONS CONTACTED

DLC

J. Cross, Senior Vice President, Nuclear Power Division
T. Noonan, Vice President, Nuclear Operations and Plant Manager
S. Jain, Vice President, Nuclear Services
L. Freeland, Manager, Nuclear Engineering
B. Tuite, General Manager, Nuclear Operations
C. Hawley, General Manager, Maintenance Programs Unit
K. Beatty, General Manager, Nuclear Support Unit
R. Brosi, Manager, Nuclear Safety
J. Arias, Manager, Licensing
K. Ostrowski, Manager, Quality Services
R. Vento, Manager, Health Physics
M. Johnston, Manager, Security
F. Schuster, Manager, System and Performance Engineering
A. Dulick, Manager, Operations Experience
F. Lipchick, Senior Licensing Supervisor
B. Sepelak, Senior Licensing Engineer

NRC

E. King, Senior Security Inspector, DRS
G. Smith, Senior Security Inspector, DRS
D. Brinkman, Project Manager, NRR

INSPECTION PROCEDURES USED

IP 37550:	Engineering
IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Operations
IP 83750:	Plant Support
IP 86750:	Plant Support
IP 90712:	In-Office Review of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92700:	Onsite Follow up of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92902:	Follow-up - Engineering
IP 92904:	Follow-up - Maintenance

ITEMS OPENED, CLOSED AND DISCUSSED

Opened

50-334/96007-01	URI	PZR PORV Block Valve Configuration Contrary to FSAR (Section O1.4).
50-334(412)/96007-03	VIO	Failure to Perform Audit of OSC Activities (Section O8.3)
50-334(412)/96007-07	VIO	Failure to Control Safeguards Information (Section S3.1)

Closed

50-334/93004	LER	Potential Post Small Break LOCO Release Path (Section E8.2)
50-412/93005	LER	Potential for Failure of a Motor Operated Valve (Section E8.2)
50-334(412)/94007-02	URI	Heat Exchanger Performance Issues (Section M2.2)
50-334/94020-01	URI	Safety Evaluation Prepared to Determine Excavated Buried River Water Lines Involved an Unreviewed Safety Question (Section E8.1)
50-334/96001	LER	Unit 1 Main Steam Safety Valve Setpoints Found High (Section M8.2)
50-334(412)/96005-01	URI	OSC Activities- a TS Requirement (Section O8.3)
50-334(412)/96S03	LER	Unaccounted for Safeguards Information (Section S8.1)
50-412/96006-01	URI	Containment Penetration Overpressure Protection (Section E8.3)
50-412/96006-02	URI	Fire Pump Capacity Issue (Section E8.2)
50-334/96007-02	NCV	Failure to Administratively Control Containment Isolation Valves (Section O8.1)
50-334/96007-04	NCV	Improper Use of Accident Probability Increase in USQ Determination (Section E8.1)
50-412/96007-05	NCV	Failure to Properly Evaluate Fire Protection System Design Change, TB Sprinkler Modification (Section E8.2)
50-334/96007-06	NCV	Improper High Radiation Area Entry (Section R8.2)

Discussed

50-412/96004	LER	Bypass Feedwater Regulating Valve Leakage Leads to Manual Reactor Trip During Shutdown for Refueling (Section O8.1)
50-334/96011	LER	Failure to Administratively Control Containment Isolation Valves as Required by TS (Section O8.2)
50-334/96006-01	URI	Containment Penetration Overpressure Protection (Section E8.3)

LIST OF ACRONYMS USED

ALARA	As Low as Reasonably Achievable
AMSAC	ATWS Mitigating System Actuation Circuitry
ANI	American Nuclear Insurers
ANS	American Nuclear Society
ANSI	American National Standards Institute
ANSI B31.1	American National Standards Institute Power Piping Code
ANSS	Assistant Nuclear Shift Supervisor
ARP	Alarm Response Procedure
ASCOA	Automatic Sprinkler Company of America
ASME	American Society of Mechanical Engineers
ASME III	American Society of Mechanical Engineers Boiler and Pressure Vessel Code,
ATWS	Anticipated Transient Without Scram
BCO	Basis for Continued Operation
BVPS	Beaver Valley Power Station
BVPS1	Beaver Valley Power Station, Unit 1
BVPS2	Beaver Valley Power Station, Unit 2
BVT	Beaver Valley Test procedure
CCR	Component Cooling Water
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
DAW	Dry Active Waste
DCP	Design Change Package
DLC	Duquesne Light Company
DRP	Division of Reactor Projects
EDG	Emergency Diesel Generator
EM	Engineering Memorandum
EOP	Emergency Operating Procedure
ESP	Engineering Support Personnel
ft^2	Square Feet
HP	Health Physics
HRA	High Radiation Area
I&C	Instrument and Control
IE	NRC Office of Inspection and Enforcement
IST	In-Service testing
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MEAD	Maintenance Engineering and Assessment Department
MOV	Motor Operated Valve
MPU	Maintenance Programs Unit
MPUAP	Maintenance Programs Unit Administrative Procedure
MSP	Maintenance Surveillance Procedure
NARC	Nuclear ALARA Review Committee
NCV	Non-cited Violation
NED	Nuclear Engineering Department
NFPA	National Fire Protection Association, Incorporated
NPDAP	Nuclear Power Division Administrative Procedure
NRC	Nuclear Regulatory Commission
NSRB	Nuclear Safety Review Board

NSS	Nuclear Shift Supervisor
ORC	Offsite Review Committee
OSC	Onsite Safety Committee
OST	Operational Surveillance Test
PCEs	Personnel Contamination Events
PDR	Public Document Room
PORV	Power Operated Relief Valves
PRA	Probablistic Risk Assessment
PZR	Pressurizer
QA	Quality Assurance
RCAs	radiologically-controlled areas
RCB	Reactor Containment Building
RCS	Reactor Coolant System
RG	Regulatory Guide
RHR	Residual Heat Removal
RP	Radiation Protection
RP&C	Radiological Protection and Chemistry
RPM	Radiation Protection Manager
RV	Reactor Vessel
RWP	Radiation Work Permit
S/G	Steam Generator
SER	Safety Evaluation Report
SI	Safeguards Information
SPED	Systems and Performance Engineering Department
sq. ft.	Square Feet
SRP	Standard Review Plan
TER	Technical Evaluation Report
TRR	Test Results Report
TS	Technical Specification
TSAP	Technical Services Administrative Procedure
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
USQ	Unresolved Safety Question
UT	Ultrasonic Testing

Predecisional Enforcement Conference

Beaver Valley Power Station

August 28, 1996

King of Prussia, PA

Duquesne Light

Duquesne Light Participants

◆ J. E. Cross	Sr. V.P. and Chief Nuclear Officer
◆ R. K. Brosi	Manager, Nuclear Safety
◆ J. Arias	Director, Licensing
◆ K. E. Halliday	Director, Electrical Engineering
◆ R. W. Fedin	Supervisor, ISEG

Agenda

- Opening Remarks
- AMSAC Background
- Problem Identification & Immediate Corrective Actions
- Preliminary Reviews & Industry Notifications
- Root Cause Analysis
- Additional Corrective Actions
- Comprehensive Actions to Prevent Recurrence
- Focused Design Reviews
- Safety Significance and Closing Remarks

AMSAC Background

- Designed in response to 10 CFR 50.62
- Provide protection against a total loss of feedwater (FW) with ATWS
- Unit 1 1988 (1R7) Unit 2 1989 (2R4)
- Foxboro design using Westinghouse Owners Group generic approved design
- Initiates on 2/3 Low FW flow signal

Problem Identification

- Unit 1 Turbine/Reactor trip May 31, 1996 (LER 1-96-008)
- Post trip follow-up ISEG Overview
- Initial assessment: expected response to a unit trip

Problem Identification (Cont'd)

- Multiple timer resets prevented actuation
- AMSAC timer fluctuations correlates with FW flow alarms
- Notified NSS, AMSAC declared inoperable
- "A" FW flow instrument signal suspected, FW system interaction with AMSAC
- Also applicable to Unit 2

Immediate Corrective Actions

- Basis for Continued Operation (BCO)
- Time limit applied (Admin. LCO) to restore in 7 days or reduce power to < 40%
- FW flow instrument calibration identified "C" instrument

Preliminary Reviews and Industry Notification

- Reviewed Industry Information available on AMSAC
- Reviewed BVPS availability information
- Reviewed past BVPS post trip data
- Initiated Nuclear Network entry to notify the industry

Root Cause Analysis

- Prior trips with data, AMSAC initiated when expected
- Root cause determined to be design incompatible with FW pressure pulsations
- Previous identified design deficiencies would not have prevented actuations

Additional Corrective Actions

- Modification to lower setpoint for a flow instrument failure
- Incorporated AMSAC modifications at both units within the seven day limits

Comprehensive Actions to Prevent Recurrence

- Conducted a focused design review of both unit's AMSAC systems
- Focused design reviews of 3 other systems
- Basis for the selection of the 3 systems:
  - Installed after initial licensing
  - Customized generic designs
  - Include T/S and non-T/S systems

AMSAC Focused Design Review

- Current design
- Additional enhancements to improve reliability:
  - Computer power supply annunciator
  - Test matrix development
  - Jumper configuration

Focused Design Review of Other Systems

- Inadequate Core Cooling Monitor
- Post Accident Sampling System
- High Energy Line Break Isolation System
- Results will be reviewed for generic conclusions with additional corrective actions as appropriate
- Schedule for completion

Safety Significance

- Required by 10 CFR 50.62
- Low Core Damage Frequency Impact of 1 E -11 without AMSAC
- If AMSAC was required and did not actuate, procedures and training are in place to ensure manual actions are taken

Closing Remarks

- Insightful identification of a subtle initial design deficiency not likely to be found through routine efforts or past reviews
- Appropriate immediate corrective actions
- Comprehensive long term corrective actions to prevent recurrence
- Expanded actions to identify similar generic issues