U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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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:	July 20, 1997 through August 30, 1997
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EXECUTIVE SUMMARY

Beaver Valley Power Station, Units 1 & 2
NRC Inspection Report 50-334/97-06 & 50-412/97-06

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 an announced inspection of the licensed operator requalification training program by regional inspectors.

Operations

- Operators responded appropriately to the Unit 1 reactor trip on August 7, and the plant responded as designed. Maintenance technicians conducted thorough troubleshooting and located the root cause of the trip, a ground in the feedwater flow controller module. The Event Review Team (ERT) conducted a rigorous and disciplined root cause analysis of the trip and provided reasonable recommendations for corrective actions to be completed prior to plant restart. There were good communications and teamwork between operations and maintenance staffs and the ERT in determining the root cause, and good interaction between the ERT and the Nuclear Safety Review Board during review of the event and corrective action recommendations. (Section O1.2)

- Operators and maintenance technicians responded promptly and effectively to the failure of a refueling water storage tank level transmitter that caused the initiation of a plant shutdown as required by Technical Specification (TS) 3.0.3. During the entry into TS 3.0.3, there were some plant staff discussions on the interpretation of TS 3.0.3 requirements which were resolved in a manner consistent with an existing operations and licensing approved TS interpretation. This occurrence highlighted the need for greater awareness of existing TS interpretations and their applicability.

- Inspectors noted several discrepancies during a routine review of the Bases for Continued Operation (BCOs) filed in the control rooms. These indicated weak administrative control of BCOs and a lack of rigor in maintaining control room drawings and System Status Print Sheets up-to-date. The discrepancies were brought to the attention of licensee management and operators and subsequently corrected. (Section O3.1)

- The licensed operator requalification training program was implemented acceptably. Annual licensed operator exams were administered appropriately, however, the inspector identified an area for improvement regarding documenting the results of the exams. The facility also corrected an inspector-identified concern on exam security. (Section O5)

- Weaknesses were noted in the administrative controls applied to BCOs and TS Interpretations and had previously been noted in Special Operating Orders and Standing Night Orders. Considered together, the administrative deficiencies indicated a lack of rigor in maintaining some of the documents provided in the control room as guidance or reference for operators. Additional management attention may be needed in this area. (Section O6)

Maintenance

- Inspectors noted good management oversight and good coordination between operators, maintenance technicians, and system engineers during the planning and recovery of Unit 2 main turbine governor valve #4. (Section M1.1)

Engineering

- Inspectors reviewed the engineering evaluation for an unresolved item identifying that main steam bypass valve closure time was slower than the time required by technical specifications for main steam isolation. The evaluation was technically sound and adequately resolved the issue. Engineers displayed a good questioning attitude in identifying the issue. (Section E1.1)

- Engineers identified that non-seismically qualified fire protection system switches and relays resulted in the Unit 1 Emergency Diesel Generators and Unit 1 & 2 supplemental leak collection and release systems being vulnerable to failure under seismic conditions since original plant operation. The discovery of these deficiencies demonstrated a thorough extent of condition review of the Unit 1 EDG fire protection non-seismic actuation relays, as described in NRC Inspection Report 50-334 and 412/97-05. NRC enforcement discretion was exercised, and no violations were issued, because the problems were licensee-identified as part of corrective action for a previous escalated enforcement action (EA 97-375) that had a similar root cause, did not substantially change the safety significance or character of the regulatory concern of the initial violation, and would be corrected within a reasonable time. (Section E1.2)

Plant Support

- Inspectors reviewed the fire suppression capability for the control room and concluded that it and emergency breathing systems for control room personnel were provided in accordance with design requirements. (Section F1.1)

Safety Assessment and Quality Verification

- The Event Review Team (ERT) conducted a rigorous and disciplined root cause analysis of the Unit 1 trip on August 7 and provided reasonable recommendations for corrective actions to be completed prior to plant restart. There was good interaction between the ERT and the Nuclear Safety Review Board in review of the event and corrective action recommendations. (Section O1.2)

- Inspectors noted good management oversight and good coordination between operators, maintenance technicians, and system engineers during the planning and recovery of Unit 2 turbine governor valve #4. The recovery was conducted in accordance with the requirements of Administrative Procedure 8.23, "Infrequently Performed Tests and Evolutions." (Section M1.1)

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Summary of Plant Status

Unit 1 began this inspection period in Mode 5 (cold shutdown) in a forced outage. Major work included installation of a median selector switch to resolve main feedwater flow transmitter seismic qualification concerns, modifications to piping supports on the normal and excess letdown lines, and modifications to three containment isolation check valves. Following completion of forced outage work, Unit 1 returned to power operation on July 31. On August 5, operators initiated a shutdown required by Technical Specification 3.0.3 due to the failure of one refueling water storage tank level transmitter while another transmitter was out of service. Load was held at 99% power and restored following the replacement of one of the transmitters (see Section O1.3). On August 7, Unit 1 tripped from full power due to high water level in the "A" steam generator (see Section O1.2). The event was caused by a ground in a feedwater flow controller. Operators stabilized the unit in Mode 3 (hot standby). Following root cause analysis and corrective action for the trip, Unit 1 returned to power operation on August 10.

Unit 2 began this inspection in Mode 5 in a forced outage. Major work included replacement of the "A" and "C" reactor coolant pump seals. Following completion of forced outage work, Unit 2 returned to power operation on July 23.

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 1 Automatic Reactor Trip on August 7

a. Inspection Scope (71707, 93702, 92901)

On August 7, Unit 1 had an automatic reactor trip from full power following a turbine trip caused by high water level in the "A" steam generator. Inspectors responded to the plant and observed the post-trip critique and subsequent licensee Event Review Team (ERT) activities.

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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.

b. Observations and Findings

Background

During the midnight shift on August 7, operators noted that the "A" steam generator level was being automatically controlled about 4% higher than the programmed level setpoint. Later in the day, the level slowly varied at slightly higher values causing occasional intermittent level deviation alarms. The level deviations began to increase in frequency and duration.

Instrumentation & Controls (I&C) technicians investigated and identified an apparent discrepancy in the readings on the current to voltage converter (LC-478 B/R I/V input module) in comparison to other modules in the flow control circuit. They initially concluded that the cause could be a loose lead or degraded internal resistors. A work order was prepared to tighten the resistor block leads, retake electrical readings, and, if necessary, replace the resistor block. Technicians and operators were properly briefed on the work. In order to prevent any adverse effect on plant operations, feedwater control for flow control valve FCV-FW-478 was placed in manual, which electrically isolated the area of work.

No loose leads were found by the I&C technicians, and they lifted leads to replace the resistor block. Coincident with lifting the leads, FCV-FW-478 failed to the full open position. Operators were unable to reduce feedwater flow with the manual benchboard controls. A turbine trip and feedwater isolation occurred at the "steam generator high-high water level" setpoint, which caused a reactor trip.

Plant Response

The plant responded as designed to the trip. A fast bus transfer on the 4kV system from the unit transformers to the system transformers occurred. As a result of the voltage reduction on the "A" and "D" 4kV buses, both emergency diesel generators (EDGs) automatically started on degraded bus voltage. The voltage reduction was not low enough to require load shedding and EDG sequencing. Bus voltages on the normal 4kV system recovered as designed without the shedding of major loads. Operators stabilized the unit in Mode 3 (hot standby). The licensee formed an Event Review Team (ERT) to validate plant response, determine root causes for the trip, and recommend required corrective actions for restart. Potentially suspect equipment was "quarantined" until as-found information could be gathered. The trip was documented in Condition Report 971364.

Root Cause

The ERT determined that the root cause of the trip was a ground in the FC-478 (Hagen Model 124 Rev. R) feedwater flow controller in the "A" steam generator feedwater control system. The ground was from an oversized solder connection which contacted the module bracket. This was confirmed by physical evidence and follow-up testing. The controller was new and had only been in service since the plant startup on July 31. The ground had apparently progressed from a weak electrical connection to a hard connection during the course of the day on August 7. The ground was not detectable during receipt inspection or routine pre- and post-installation testing. The work being done by I&C technicians was electrically isolated from the controller and was coincident to the controller failure. The controller module was replaced with a new one prior to unit restart.

Licensee Investigation

Inspectors observed the post-trip critique, portions of the ERT investigation, and the ERT presentation to the Nuclear Safety Review Board (NSRB). The ERT was conducted in accordance with Nuclear Power Division Administrative Procedure (NPDAP) 5.6, Rev.0, "Processing of Condition Reports," and NPDAP 5.8, Rev.0, "Root Cause Analysis." The ERT conducted a rigorous and disciplined root cause analysis of the trip and provided reasonable recommendations for corrective actions to be completed prior to plant restart. Inspectors noted good communications and teamwork between operations and maintenance staffs and the ERT in determining the root cause, and good interaction between the ERT and the NSRB in review of the event and corrective action recommendations. Inspectors noted that the ERT maintained a clear focus on their responsibilities. There was little of the confusion over ERT roles and interface with the NSRB that was seen following some previous events (for example, see NRC Inspection Report 50-334 and 412/97-02, Section O1.2). Inspectors assessed that the improvement was due to a strong focus by the ERT manager and leader and the relatively uncomplicated nature of the event, since no program changes had been implemented. Inspectors reviewed the ERT report (NPDMQS:1302) and ISEG analysis (NDISEG:1134) and assessed them to be thorough dispositions of issues from the event. The "anomaly matrix" in the ERT report was a useful method of tracking issues requiring additional investigation, follow-up, or corrective action.

c. <u>Conclusions</u>

Operators responded appropriately to the event, and the plant responded as designed. Maintenance technicians conducted thorough troubleshooting and located the root cause of the trip, a ground in the feedwater flow controller module. The ERT conducted a rigorous and disciplined root cause analysis of the trip and provided reasonable recommendations for corrective actions to be completed prior to plant restart. Inspectors noted good communications and teamwork between operations and maintenance staffs and the ERT in determining the root cause, and good interaction between the ERT and the NSRB during review of the event and corrective action recommendations.

O1.3 Unit 1 TS 3.0.3 Entry on August 5

a. Inspection Scope (71707, 93702, 92901)

On August 5, Unit 1 entered TS 3.0.3 and began a plant shutdown due to the failure of one refueling water storage tank (RWST) level transmitter while a second transmitter was out of service for scheduled replacement. Inspectors observed the operators' response to the event and subsequent licensee recovery actions.

b. Observations and Findings

Sequence of Events

Maintenance technicians were replacing RWST level transmitter LT-QS-100C in accordance with MWR 63665 (TER 10485, replacement of obsolete transmitters). Operators had confirmed that the work was permissible from a probabalistic risk perspective and entered the appropriate TS for having one of the four RWST level channels out of service (TS 3.3.2.1.b, Table 3.3-3, Actions 16 and 18). At 1:30 p.m., about three hours into the work, control room operators noted during a review of computer alarms that LT-QS-100B had failed high at 1:14 p.m. Operators applied TS 3.0.3 and initiated a plant shutdown at 2:12 p.m. The load reduction was halted at 99% power, since there was a high degree of confidence that the work on LT-QS-100C could be completed expeditiously.

LT-QS-100C was replaced, tested satisfactorily, and returned to service at 3:41 p.m. TS 3.0.3 was exited at that time. Unit 1 remained in TS 3.3.2.1 action 16 since LT-QS-100B was still out of service. Operators returned Unit 1 to full power; LT-QS-100B was subsequently replaced and returned to service. The NRC was notified of the initiation of a plant shutdown required by TS in accordance with 10CFR50.72.

TS 3.0.3 Interpretation

During the entry into TS 3.0.3, there were some plant staff discussions on the interpretation of TS 3.0.3 requirements which were resolved in a manner consistent with an existing Operations and Licensing approved interpretation. This occurrence highlighted the need for greater awareness of existing TS interpretations and their applicability. The issue was documented on Condition Report 971392. Inspectors discussed the issue with management and operators. The Director, Safety & Licensing, stated that the licensee intended to review all of the existing TS interpretations by the end of the year to verify their applicability.

c. Conclusions

Operators and maintenance technicians responded promptly and effectively to the failure of an RWST level transmitter that caused the initiation of a plant shutdown as required by TS 3.0.3. Plant staff initial uncertainties about the appropriate interpretation of TS 3.0.3 highlighted the need for greater awareness of existing TS interpretations and their applicability.

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 2 Charging Pumps
- Unit 2 Service Water System
- Unit 2 Auxiliary Feedwater System
- Unit 1 River Water System

O3 Operations Procedures and Documentation

O3.1 Bases for Continued Operation (BCOs)

a. Inspection Scope (71707)

Inspectors reviewed the BCO files and logs maintained in the Unit 1 and 2 control rooms. The review included Nuclear Power Division Administrative Procedure (NPDAP) 5.7, Rev.0, "Basis for Continued Operation Determination," operating procedure 1/2OM-48.3.D, Rev.17, "Administrative Control of Valves and Equipment," and a sample of the contingency and compensatory measures in place taken for BCOs.

b. Observations and Findings

Inspectors reviewed the BCO logs and files for both units and noted the following discrepancies:

(1) The log comments for BCO 1-96-007, Rev.1, stated that a type-C test would be required if leakage exceeded 3 gph. This was the requirement of the original BCO; however, Rev.1 had changed the requirement to 5 gph.

(2) Several of the control room valve operating number diagram (VOND) drawings did not match the System Status Print Sheet deviation numbers. The print sheet deviation number reflects the clearance (tagout) number on a valve or component which is out of its normal system alignment. For example, the print sheet for OM Figures 34-1 and 2 (Station Air and Instrument Air) showed deviations F, W, J-1, Q-1, and R-1, but these deviations were not reflected on the drawing. Valve 1SA-14 was labeled as deviation R, but deviation R was closed on the print sheet (the correct label was R-1).

(3) The Unit 2 log status summary indicated that there were 5 active BCOs as of July 31, but there were 6 BCOs listed as open in the log. BCO 1-94-005 (which applied to both units) was not in the file. It had been closed prior to the last Unit 2 startup, but the log had not been updated. The log was later changed to reflect that the BCO was closed by Safety & Licensing Department letter ND3NSM:7804 dated July 29, 1997, but the letter only closed the BCO for Unit 1. The closeout letter for Unit 2 was subsequently generated on August 25 (ND3NSM:7834), though the actual work had been completed in July before Unit 2 restart.

(4) BCO 2-97-003 was closed but was still in the file.

(5) Two document copies, each labeled BCO 2-97-004, were in the Unit 2 file. Each referenced a different Condition Report, one from January (CR 970077) and one from July (CR 971140). Neither document copy had all of the approval signatures required by NPDAP 5.7. Upon further review, the inspectors found that the July document had never completed the BCO approval process, because it had been rejected by the OSC. The January BCO 2-97-004 had been approved by the OSC, but the control room copy did not have the OSC approval on it.

Inspectors assessed that these discrepancies indicated weak administrative control of BCOs and a lack of rigor in maintaining the control room VOND drawings and System Status Print Sheets up-to-date. The discrepancies were discussed with operations management. Operators subsequently audited and updated the control room VOND drawings and System Status Print Sheets and updated the BCO logs and files.

Inspectors made the following observations:

(1) NPDAP 5.7 did not clearly specify the organization responsible or the process to be used for closing a BCO.

(2) NPDAP 5.7 requires that periodic reviews of open BCOs be performed by System & Performance Engineering (SPED) and Nuclear Licensing Departments. These reviews were not documented. NPDAP 8.13, Rev.0, "Nuclear Safety Review Board (NSRB)," required the NSRB to review BCOs. The NSRB reviews of BCOs were documented in the NSRB meeting minutes, but were not noted on the BCO approval form. The Plant Manager was not required by NPDAP 5.7 to approve BCOs.

(3) Inspectors noted that several valves were caution tagged as compensatory measures for BCOs. However, in some cases the clearances did not refer to the BCO, for example, Clearance 661902 for 1SA-14 and Clearance 661900 for 1BR-16 and 17. The potential existed for a clearance to be removed without recognizing that it was fulfilling a BCO compensatory action.

Inspectors discussed the observations with operations, SPED, and licensing staff. The Director, Safety & Licensing, stated that NPDAP 5.7 was being evaluated and that a revision was expected by mid-October to strengthen the program. The revision was being tracked under Condition Reports 970941 and 971222.

c. Conclusions

Inspectors noted several discrepancies during a routine review of BCOs and other files in the control rooms. These indicated weak administrative control of BCOs and a lack of rigor in maintaining control room VOND drawings and System Status Print Sheets up-to-date. The discrepancies were brought to the attention of licensee management and operators and subsequently corrected.

O5 Operator Training and Qualifications

O5.1 General Scope (71001)

A scheduled inspection of the Beaver Valley Power Station (BVPS) Unit 1 & 2 licensed operator requalification program was conducted from July 28 - August 1, 1997, using NRC Inspection Procedure 71001. The scope of the inspection included the observation of the annual operating exams administered to one crew of licensed operators, the review of previously completed annual exams for both units, remedial actions taken for exam failures, and reactivation of inactive licenses.

O5.2 Exam Content

a. Inspection Scope

The inspector reviewed annual written exams for the current and past year and also weekly training quizzes. Operating exams, which included simulator scenarios and job performance measures (JPMs), were also reviewed for both units.

b. Observations and Findings

The inspector reviewed several written exams, simulator scenarios and job performance measures that were part of the annual licensed operator requalification exams administered to senior reactor operators and reactor operators. The inspector found the written exams, Parts A and B, to be adequately constructed with an appropriate number of questions at the comprehension level. The simulator scenarios were diverse and included a wide spectrum of the emergency operating procedures. JPMs were also of good quality.

c. Conclusions

The facility had developed annual licensed operator requalification exams that indicated whether or not licensed operators were maintaining an acceptable knowledge level of plant operation.

05.3 Exam Administration and Evaluation

a. Inspection Scope

The inspector observed one crew complete two sections of the written examination, perform two simulator scenarios, and perform five JPMs. The inspector also reviewed the facility evaluation of the crew and individual performance.

b. Observations and Findings

The crew and individuals, observed by the inspector, passed their operating examinations; however, one individual failed the written examination.

Crew and individual operator performance was good during the conduct of the two simulator scenarios. Also, performance of JPMs was acceptable in all instances for those observed by the inspector, which included both simulator and inplant JPMs.

The evaluations by training and operations department evaluators were effective for those portions of the exam observed by the inspector. A review of previously completed exam packages, however, indicated that, in a few instances, documentation was not as detailed or complete as it should have been. This concern applied to both the crew performance documentation for the simulator scenario portion of an exam and to individual performance during the conduct of JPMs. BVPS management was made aware of the inspector's concern and agreed to make the necessary improvements to address and correct this concern.

The inspector also noted during the written exam briefing that individuals were permitted, one at a time, to take unescorted trips to the rest room. Based on the potential for compromise of the exam, the inspector stated that individuals should not be allowed unescorted passage since the rest room facilities were not located within the confines of the proctored exam room or examination area. The facility agreed and ceased the practice. The facility noted that this practice had occurred very infrequently in the past due to the relatively short exam period (< 2 hours) and that exam compromise had been unlikely due to specific instructions prohibiting use of non-exam materials or assistance. Further, BVPS management initiated program changes to prevent any future unescorted or unproctored rest room visits.

c. Conclusions

The annual licensed operator requalification exams were administered and evaluated acceptably; however, program enhancements were warranted in evaluation documentation, and an exam security concern was corrected.

05.4 Continuing Training

a. Inspection Scope

The inspector reviewed portions of the BVPS licensed operator requalification training program to ensure that a continuous two year training program was in place and had been implemented as required by 10 CFR 55.59.

b. Observations and Findings

The inspector observed the conduct of classroom training given to licensed operators as part of their annual requalification training and found this training acceptable. Lesson plans were also reviewed and found to be well-structured along with detailed enabling and terminal objectives. The inspector specifically attended the conduct of two classroom training sessions, one of which included a review of plant and industry events, and the other which dealt with upcoming plant modifications. Classroom interaction was very good, with the instructors handing out detailed lesson plans and using visual aids, as necessary, to further describe the subject matter.

The inspector also reviewed individual study guides for licensed operators for both units. Licensed operators had recently experienced some difficulty in identifying applicable technical specification (TS) requirements under actual operating plant conditions. As a result of this problem, the training department utilized the individual study guide process as one of the interim corrective measures until formalized classroom and simulator training could be accomplished. These study guides reviewed several BVPS plant condition reports in which TSs were missed or misinterpreted. Also included within this study guide were several scenario questions with various plant conditions in which the individuals had to identify the applicable TS along with other TS-related questions. The licensed operators' answers to these scenario questions were then to be forwarded to the training department for review and subsequent onshift discussion.

The inspector also reviewed several BVPS licensee event reports (LERs) in which the facility committed to additional training as part of the corrective action for a given problem that had occurred at either of the two units. The inspector verified that the training commitments had been completed as designated in the various LERs reviewed by the inspector.

c. Conclusions

The BVPS training facility had implemented a continuing licensed operator training program that met administrative and regulatory requirements. Classroom training was found to be very good in the development and distribution of lesson plans, use of visual aids, and classroom interaction.

05.5 Remedial Training

a. Inspection Scope

The inspector assessed the adequacy and effectiveness of remedial training conducted during the examination cycle, including training provided to licensed operators to correct deficiencies that resulted in a failure of their annual operating exam.

b. Observations and Findings

The inspector reviewed remedial actions taken for those licensed individuals who had failed their annual licensed operating exam. In this instance, the inspector reviewed the failure of the written exam for three different individuals during three different exam weeks. The inspector noted that appropriate notifications were made, which included informing operations that the individuals would be precluded from performing watchstanding duties until they successfully passed a retake exam for those sections which they had failed. Documentation of remediation included a review of areas of weakness with the individuals and a retake of a completely different exam. In all three instances, the individuals passed their retake written examination.

c. Conclusions

The inspector concluded that the BVPS training department had taken appropriate action in regard to those individuals who had failed any portion of their annual licensed operator exam. For those failures reviewed by the inspector, appropriate remedial action had been taken, and documentation was acceptable.

05.6 License Reactivation

a. Inspection Scope

The inspector reviewed the program requirements for reactivation of licenses from inactive to active status.

b. Observations and Findings

The inspector reviewed the facility's program for restoration of active operator license status following inactivation and found the program to be acceptably documented and administered. The records of two licensed operators, whose licenses had been recently reactivated, were reviewed. The inspector noted that the records were complete and reactivation requirements had been met in accordance with administrative and 10 CFR 55.53(f) requirements.

c. Conclusions

The inspector determined that the facility had adequately implemented the program requirements for reactivation of licenses for operators at BVPS Unit 1 and 2.

O6 Operations Organization and Administration (71707)

Inspectors noted weaknesses in the administrative controls applied to BCOs and other control room files, as noted in Section O3.1, and TS Interpretations, as noted in Section O1.3. In NRC Inspection Report 50-334 and 412/97-04, Section O3.1, deficiencies were noted in the control of Special Operating Orders and Standing Night Orders, which resulted in a Non-Cited Violation. Considered together, however, the administrative deficiencies indicated a lack of rigor in maintaining some of the documents provided in the control room as guidance or reference for operators. Periodic reviews appeared to be ineffective in identifying and correcting administrative deficiencies and ensuring quality. Additional management attention may be needed in this area.

O7 Quality Assurance in Operations

O7.1 Offsite Review Committee (71707)

Inspectors observed portions of the Offsite Review Committee (ORC) meeting on August 6 and portions of the Safety Evaluation Subcommittee and Maintenance and Engineering Subcommittee meetings on August 4 and 5. Inspectors verified the ORC met the quorum and membership requirements of TS 6.5.2. Reviews of station activities were thorough and self-critical with a focus on nuclear safety, with good participation by all members. Inspectors assessed that the committee was effective in providing the independent review of activities required by TSs.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) Licensee Event Report (LER) 50-412/97-01: Reactor Trip Due to Main Transformer Ground Protection Relay.

This event was discussed in NRC Inspection Report 50-334 and 412/96-10. No new issues were revealed by the LER. The inspectors verified that the corrective actions described in the LER were completed and that the reporting criteria required by 10CFR50.73 were properly addressed.

O8.2 (Closed) LER 50-412/97-02: Technical Specification Required Shutdown Due to Missing or Degraded Recirculation Spray System Pump Flood Seals.

This event was documented in NRC Inspection Report 50-334 and 412/96-10. No new issues were revealed by the LER. The inspectors verified that the corrective actions described in the LER were completed and that the reporting criteria required by 10CFR50.73 were properly addressed.

O8.3 (Closed) Violation (VIO) 50-334 and 412/96-07-03: Failure to Perform Audit of Onsite Safety Committee (OSC) Activities.

The licensee failure to conduct quality assurance audits of the OSC was a violation and was cited/discussed in NRC Inspection Reports 50-334 and 412/96-10 and 50-334 and 412/96-05. The licensee response to the violation was received by letter dated December 9, 1996. The inspectors examined the root cause evaluation and corrective actions to prevent recurrence of the violation.

The licensee investigation concluded that a misinterpretation of audit requirements was the root cause. In 1992, Quality Services Unit (QSU) management decided to implement performance based auditing techniques. At this time, licensee management deleted the OSC audit. The QSU review of the OSC responsibilities was considered to be already covered in other audits (such as Operations, Maintenance, and various other audits). The justification for this decision was not documented. Corrective actions to address the root cause and NRC concerns were completed as listed:

- A self assessment of the QSU's overview of the OSC and Section 6 of the Technical Specifications (TS) was conducted.
- Quality Service Procedure (QSP) 18.1 "Audit Schedules" was revised to include biennial audits of Section 6 of the TSs including site oversight groups (OSC, NSRB, ISEG, and the ORC).

The inspectors independently verified that the corrective actions were completed and reviewed the completed audit of the site oversight groups. The corrective actions adequately addressed the root cause and the violation. The violation is closed.

O8.4 (Closed) LER 50-334/97-05-01: Inadvertent Operation of 345kV Bus Backup Timer Relay Results in Dual Unit Reactor Trips.

The issue was reviewed and documented in NRC Inspection Report 50-334 and 412/97-02. The LER update reflected the 10CFR21 notification made subsequent to the event regarding the auxiliary feedwater check valve failure. The check valve failure and 10CFR21 determination were documented in the NRC report, Section E1.4.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Routine Maintenance Observations (62707)

The inspectors observed selected maintenance activities on important systems and components. Some of the maintenance work request (MWR) activities observed and reviewed are listed below.

- MWR 065703 "Unit 2 Turbine Governor Valve #4 Repositioning"
- MWR 065704 "Install Temporary Modification 2-97-15 on 2TMS-GV4"

The activities observed and reviewed were performed safely and in accordance with proper procedures. Inspectors noted that an appropriate level of supervisory attention was given to the work depending on its priority and difficulty. Particularly good work was noted during the recovery of Unit 2 main turbine governor valve #4 (GV4) (MWRs 065703 and 065704). During routine surveillance testing, operators noted that the valve position did not indicate as expected during the test. Investigation revealed that the limit switch linkage rod had become unthreaded from the valve stem coupling. Since the rod also serves as the anti-rotation device, the valve stem had rotated about 60 degrees. A temporary collar was installed to prevent further rotation and restore position indication. The work was properly controlled. Inspectors noted good management oversight and good coordination between operators, maintenance technicians, and system engineers during the planning and recovery of GV4. The recovery was conducted in accordance with the requirements of Administrative Procedure 8.23, "Infrequently Performed Tests and Evolutions."

M1.2 Routine Surveillance Observations (61726)

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

- 2OST-1.11C "Safeguards Protection System Train A CIB/Spray Actuation Test," Rev. 6
- 2OST-36.1 "Emergency Diesel Generator [2EGS*EG2-1] Monthly Test," Rev. 8
- 1OST-7.5 "Centrifugal Charging Pump Test [1CH-P-1B]," Rev. 11
- 1OST-36.2 "Diesel Generator No.2 Monthly Test," Rev. 19
- 1OST-30.6 "Reactor Plant River Water Pump 1C Test," Rev. 13
- 1OST-30.4 "Reactor Plant River Water System Valve Test for A Header," Rev. 11

- 2OST-1.12C "Safeguards Protection System Train B CIB/Spray Actuation Test," Rev. 8

- 2OST-26.1 "Turbine Throttle, Governor, Reheat Stop and Intercept Valve Test," Rev. 13

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.

M8 Miscellaneous Maintenance Issues (92700)

M8.1 (Closed) Licensee Event Report (LER) 50-412/96-010: Migration of Leak Sealant Material into the Reactor Head Vent System.

The issue was reviewed and documented in NRC Inspection Report 50-334 and 412/96-08 and 96-09. A Notice of Violation was issued on March 10, 1997. Additional review by inspectors will be documented in the closeout of the violation.

III. Engineering

E1 Conduct of Engineering

E1.1 (Closed) Unresolved Item (URI) 50-334/97-02-10: Acceptability of MSIV Bypass Valve Closure Time.

a. Inspection Scope (37551)

DLC identified that main steam insolation bypass valve closure time was slower than the technical specification (TS) time required for main steam isolation. The immediate corrective action was technically sound in addressing the issue. This item, described in Inspection Report 50-334 and 412/97-02, remained unresolved pending determination of whether the existing MSIV bypass valve closure time violated the TS requirements.

b. Observations and Findings

Inspectors reviewed the Updated Final Safety Analysis Review (UFSAR), TSs, and engineering evaluations by the Nuclear Steam Supply System (NSSS) vendor and the licensee. Inspectors also discussed MSIV bypass valve design basis assumptions with DLC engineering and licensing staff.

The review of the UFSAR and the TSs showed that there was not a clear indication of whether or not the MSIV bypass valve was assumed to be included in the TS requirement. The TS requirement is for main steam isolation within 8 seconds of an Engineered Safety Feature (ESF) signal. The MSIV bypass valves receive an ESF signal to close but reach the closed position between 11 and 18 seconds later. The bypass valves are normally closed and are used during startup to equalize the pressure across the MSIVs prior to opening. The MSIV bypass valves have an automatic mechanical interlock that allows only one bypass valve to be open at a specific time.

DLC engineers and the NSSS vendor determined that having one MSIV bypass valve failed open is encompassed by design basis calculations. Therefore, DLC engineers determined that the main steam isolation described in the TS does not apply to the MSIV bypass valves. The UFSAR was updated to reflect the findings and to update the description of the MSIV bypass valves. Previous administrative controls on the valves were also removed.

The inspectors reviewed the calculations and the determination by DLC engineers. The inspectors observed that the licensee appropriately evaluated the issue and documented their determination. The inspectors assessed that no regulatory requirements were violated. 10CFR50.59 safety analyses were appropriately performed for the UFSAR changes. The original identification of the issue by DLC engineers demonstrated a good questioning attitude.

c. Conclusion

DLC engineers displayed a good questioning attitude in identifying a possible non-compliance with technical specification. The inspectors determined that the evaluations addressing the issue were technically sound. The inspectors assessed that no regulatory requirements were violated.

E1.2 Non-Seismically Qualified Fire Protection System Adversely Affects Safety-Related Equipment

a. Inspection Scope (37551)

On July 24, 1997, engineers determined that non-seismically qualified pressure switches in the Unit 1 emergency diesel generator (EDG) ventilation system could make the EDGs inoperable during a seismic event. On July 26, engineers determined that non-seismically qualified relays in the Unit 1 supplemental leak collection and release system (SLCRS) water deluge fire suppression systems could make both trains of SLCRS inoperable during a seismic event. On August 21, engineers identified that the Unit 2 SLCRS also had non-seismically qualified relays that could make both trains inoperable during a seismic event. The inspectors interviewed engineers, reviewed design documents, and performed system walkdowns to assess the evaluation of these issues.

b. Observations and Findings

On July 5, 1997, engineers determined that non-seismically qualified relays installed in the Unit 1 Emergency Diesel Generator (EDG) room carbon dioxide (CO_2) fire suppression systems could make both EDGs inoperable during a seismic event as documented in NRC Inspection Report No. 50-334 & 412/97-05. During the extent of condition review, the engineers identified that Unit 1 and Unit 2 SLCRS fire suppression systems had similar vulnerabilities. In addition, the Unit 1 EDG ventilation system also had non-seismically qualified switches which could result in loss of power to the EDG room fans following a seismic event.

The engineering group "extent of condition review" following the initial discovery of the EDG inoperability evaluated the following areas:

- All Unit 1 fire protection systems were reviewed to ensure that inadvertent operation of the fire protection system would not impair the safety capability of structures, systems, or components important to safety.

- All Unit 2 automatically operated fire protection systems were reviewed to ensure that inadvertent operation of the fire protection system would not impair the safety capability of structures, systems, or components important to safety. The review of manually actuated systems is scheduled for completion on October 31, 1997.

- The other outliers in the Unit 1 Seismic Qualification Upgrade program database were reviewed for any additional potential common failure modes.

- A detailed review of the fire protection subsystems at both units (water deluge, CO2, halon, and fire detection) to verify that there were no other instances where QA Category F devices were designed into QA Category I electrical circuits. This review is scheduled to be complete by November 9, 1997.

EDG room fire protection pressure switches PS-FP-CDL1A & B were purchased as part of the fire protection system which is not procured to the same quality standards as safety related equipment. By design, upon sensing a CO2 discharge within the EDG room, the normally closed pressure switch contact in the EDG ventilation system control circuit opens, stopping the ventilation fan for that EDG room and keeping the CO2 from being removed from the room. Engineers determined that without the required quality assurance level category, the pressure switch contacts must be assumed to fail open during a seismic event. This would result in a loss of EDG room ventilation. If the EDG had been called on to operate during this event, the EDG room temperature would gradually increase above design operating temperatures and the EDG would become unable to perform its safety function. Qualified replacement switches were installed and the EDGs were declared operable on July 27. The inspectors noted that recent improvements have been made to the station's industry operating experience review program and extent of condition review processes to increase the likelihood that issues such as this will be identified more promptly.

On July 26, engineers identified that the Unit 1 SLCRS water deluge fire suppression system actuation relays could inadvertently operate during a seismic event. Since the Unit 1 SLCRS fire protection system is an automatic initiation system with non-seismically qualified actuation relays, the postulated seismic event could cause the actuation relays to chatter and actuate. The water deluge would saturate the SLCRS emergency filters. With the filters saturated, the Unit 1 SLCRS system would be inoperable.

The engineers identified that the Unit 2 SLCRS water deluge fire suppression system could inadvertently operate during a seismic event. The Unit 2 SLCRS fire protection system is a manual initiation system with a non-seismic seal-in relay for a push button switch. The postulated seismic event would cause the seal-in relay to chatter and actuate. The actuation would cause a water deluge of the SLCRS emergency filters. With the filters saturated, the Unit 2 SLCRS would be inoperable.

Unit 1 UFSAR, Section 9.10 and Unit 2 UFSAR, Section 9.5.1.1, state that the fire protection system is designed on the basis that a rupture or inadvertent operation will not significantly impair the safety capability of structures, systems, or components important to safety or designed to seismic category I requirements. Upon discovery of the discrepancies in both the Unit 1 and Unit 2 SLCRS, the licensee took prompt compensatory measures to manually isolate the fire headers to the SLCRS fire protection system and to conduct hourly fire tours. The inspectors determined that the operability determination and compensatory measures were both prompt and appropriate. As long-term corrective actions, the licensee is evaluating replacing the non-seismic relays with seismically qualified relays or qualifying the existing relays.

The inspectors determined that Unit 1 EDGs and the Unit 1 & 2 SLCRS had been vulnerable to failure under seismic conditions since original plant operation. The licensee failed to recognize the EDG and SLCRS condition and therefore failed to implement the TS required actions. These were violations of regulatory requirements. The deficiencies were identified by the licensee as part of the corrective actions in response to the EDG fire protection deficiency. The NRC exercised enforcement discretion (EA 97-375) for the EDG fire protection deficiency in NRC Inspection Report 50-334 and 412/97-05. The new deficiencies had the same root cause as the previous deficiency. The violations did not change the safety significance or the character of the regulatory concern arising out of the initial violation, and the immediate and long-term corrective actions are comprehensive and reasonable. These violations of NRC requirements will not be cited in accordance with Section VII.B.4 of the NRC Enforcement Policy **(EEI 50-334 and 412/97-06-01)**.

c. Conclusions

Engineers identified that non-seismically qualified fire protection system switches and relays resulted in the Unit 1 EDGs and Unit 1 & 2 SLCRS being vulnerable to failure under seismic conditions since original plant operation. The discovery of these deficiencies demonstrated a thorough extent of condition review of the Unit 1 EDG fire protection non-seismic actuation relays. In recognition of the licensee self-identification and comprehensive extent of condition review, the NRC is exercising discretion and not citing this violation in accordance with the NRC Enforcement Policy.

E8 Miscellaneous Engineering Issues (92700)

E8.1 (Closed) Licensee Event Report (LER) 50-334/97-019: Containment Penetration Check Valves Not in Accordance with the Design Basis.

The issue was reviewed and documented in NRC Inspection Report 50-334 and 412/97-05, Section E1.4. Corrective actions were completed or were being tracked in the licensee's corrective action system.

E8.2 (Updated) LER 50-334/97-018: Potential for Spurious Seismically Induced Fire Protection System Activation Affecting Emergency Diesel Generators.

The issue was reviewed and documented in NRC Inspection Report 50-334 and 412/97-05, Section E1.3. The licensee findings from the extent of condition review are the subject of Section E1.2 above. The LER will remain open pending completion of licensee corrective actions.

E8.3 (Updated) LER 50-334/97-021: Potential for Seismic Event to Result in Both Trains of Supplementary Leak Collection and Release System to Become Inoperable.

The issue was reviewed and documented in Section E1.2 above. The LER will remain open pending completion of licensee corrective actions.

E8.4 (Closed) LER 50-334/97-009: Main Steam Isolation Bypass Valves Do Not Meet Technical Specification Engineered Safety Feature Response Time Requirements.

The issue was reviewed and documented in Section E1.1 above. Corrective actions were completed.

E8.5 (Closed) Unresolved Item (URI) 50-334/96-06-01: Containment Penetrations Not in Accordance With the Design Basis.

The issue arose after a licensee engineering review revealed that some Unit 1 and 2 liquid-filled lines passing through containment were not designed to compensate for the effects of liquid thermal expansion during a design basis accident (DBA). This could result in pressures exceeding the system design pressure and jeopardize the structural integrity of the associated containment penetrations during a DBA. The issue was documented in NRC Inspection Reports 50-334 and 412/96-06 and 96-07 and was an unresolved item pending completion of licensee evaluation and NRC review. The licensee reported the issue to the NRC in Licensee Event Reports (LERs) 50-334/96-009 and 96-009-01.

Nuclear Engineering staff completed a comprehensive review of 145 Unit 1 and 128 Unit 2 containment penetrations utilized for piping and access to verify and document their adequacy. Penetrations for electrical equipment, which are gas-filled, were designed against the concern of overpressure due to entrapped fluids and were excluded from the review. The licensee reviews were documented in "BVPS Unit 2 Containment Penetrations Overpressure Protection Analysis/Review Report" (ND1DEA:0016, dated October 28, 1996) and "BVPS Unit 1 Containment Penetrations Overpressure Protection Analysis/Review Report" (ND1DEA:0021, dated November 27, 1996). Containment penetrations were grouped into separate review categories depending on their design. The valve configuration of each penetration was reviewed and verified in the field. The reviews were summarized on individual penetration review sheets, which included such information as design requirements, overpressure protection/justification, corrective actions, and validation of orientation and pressure relief path and references. Inspectors reviewed the design basis documents and the action plans developed to limit pressures in the penetrations subject to the effects of liquid thermal expansion. The analyses were thorough and adequately justified the conclusion that the Unit 1 and 2 containment penetrations were in compliance with applicable design codes after appropriate compensatory measures were implemented. Short term corrective actions were complete, such as administrative controls to ensure penetrations are drained after use, valve line-up controls to maintain vent paths, and relief valve setpoint adjustments, as appropriate. Long term corrective actions (per letter ND3MNE:7669, dated February 7, 1997) were tracked in the Commitment Action Tracking System (CATS items 970134A-K and 970135A-L), such as implementing permanent administrative controls or installing relief valves as permanent repairs. Long term items were scheduled to be complete by the end of each unit's next refueling outage (1R12 and 2R7).

Unit 1 UFSAR section 5.3.3 and Unit 2 UFSAR section 6.2.4.2 require that lines passing through containment that may contain trapped liquid be protected against the effects of liquid thermal expansion and piping overpressurization during a DBA. Failure to provide overpressure protection in accordance with the design basis is a violation of 10CFR50, Appendix B, Criterion III, "Design Control." This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.I of the NRC Enforcement Policy **(NCV 50-334 and 412/97-06-02)**.

E8.6 <u>(Closed) LERs 50-334/96-009 and 96-009-01</u>: Containment Penetrations Not in Accordance With the Design Basis.

The LERs were reviewed as documented in Section E8.5. Corrective actions were completed or were being tracked in the licensee's corrective action system.

E8.7 (Closed) LER 50-334/96-010: Containment Piping Supports Not in Accordance With the Design Basis.

The issue was identified by the licensee as part of their engineering evaluation to assess the ability of containment penetration lines to withstand the effects of thermal expansion, as documented in Section E8.5. The piping supports were on lines associated with containment penetrations 26 (component cooling water from reactor coolant pump 1A thermal barrier), 29 (primary drain transfer pump discharge), and 38 (containment sump pump discharge). Unit 1 was in cold shutdown at the time of discovery, and the piping supports were modified to meet UFSAR stress requirements before startup. Corrective actions for the LER were completed. An additional sample of small bore piping was inspected and no other deficiencies were identified. The failure to maintain the piping supports in accordance with the UFSAR design requirements and 10CFR50, Appendix B, Criterion III, "Design Control," constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy **(NCV 50-334/97-06-03)**.

IV. Plant Support

L1 Review of FSAR Commitments (37551)

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compared plant practices, procedures and/or parameters to the UFSAR description.

While performing the inspections discussed in this report, the inspectors reviewed the applicable parts of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters with the exceptions noted in Sections E8.5 and E8.7.

F1 Control of Fire Protection Activities

F1.1 Control Room Fire Suppression

a. Inspection Scope (71750)

In response to a recent industry operating event (ENS 32736), inspectors reviewed the fire suppression capability for the control room. The review included applicable sections of the operating license, UFSAR, QA Plan, and administrative and operating procedures for both units. Inspectors also discussed the issue with operators, the fire protection engineer, and radiation technicians.

b. Observations and Findings

The control room (including both the Unit 1 and Unit 2 sides) at Beaver Valley does not have an automatic fire suppression system. Fire suppression in the control room is accomplished by portable extinguisher and hose.

The most specific requirements for the use of emergency breathing apparatus for the control room are in the UFSARs. Unit 1 UFSAR Section 9.13, Ventilation Systems, states that, "A portable, self-contained breathing apparatus (SCBA) is provided for control room personnel. Each self-contained unit will provide 6 to 8 hours of air to the user. Four units will be provided for every three people normally in the control room. Additionally, six hours of bottled air will be stored on site for each member of the emergency crew." Unit 2 UFSAR section 6.4, Habitability Systems, states that, "A control room air manifold system which consists of flexible hose connections to air storage bottles is provided to ensure chlorine-free air for up to 6 hours...In addition, a sufficient quantity of portable SCBA...are provided for operators who are located in the control room." Other sections of the UFSARs also refer to the SCBAs and bottled air, generally without specifying quantities.

The emergency breathing systems would be used in accordance with procedures 1/2OM-53C.4A.44A.1, "Chlorine/Toxic Gas Release," and 1/2OM-53C.4A.44A.2, "Emergency Breathing Air System Operation." In general, these procedures require entry when control room environmental conditions or outside air sources have deteriorated, based on the Nuclear Shift Supervisor's discretion.

Eight MSA Ultravue Airline respirators, hoses and regulators are provided for control room operators to use the Control Room Emergency Breathing Air System (CREBAS), a supply of bottled air. The system is designed to provide air for eight people for from 8 hours (light activity) to 3 hours (heavy work).

Also, SCBA units are provided for operators. These are located in areas adjacent to or near the control room and are checked during performance of inspection procedure RP 10.22, "Emergency SCBA Weekly Surveillance." The acceptance criteria for the surveillance is $\geq$17 BioPak units and $\geq$23 MSA Air Mask units with $\geq$40 spare air cylinders. From the most recent inspection, 17 BioPaks, 35 MSA Air Masks, and 47 spare cylinders were available. The minimum number of SCBAs was calculated to provide 5 hours of air to the control room crew (13) plus four additional members of the emergency squad outside the control room, in accordance with Regulatory Guide (RG) 1.78, "Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release." The minimum number was also calculated to meet the requirements of 10CFR50 Appendix R, section II.H. An additional one hour of air would be supplied to the control room by the Control Room Emergency Bottled Air Pressurization System (CREBAPS, not to be confused with CREBAS) to meet the remainder of the RG 1.78 six-hour requirement. Inspectors reviewed the basis for the minimum SCBA requirements as documented in ISEG letter NDISEG:1097 dated January 22, 1997.

c. Conclusions

Inspectors concluded that fire suppression capability for the control room and emergency breathing systems for control room personnel were provided in accordance with design requirements.

V. Management Meetings

X1 Exit Meeting Summary

An exit meeting to discuss the inspection of the licensed operator requalification program was conducted on August 1, 1997, with Mr. J. Cross and members of his staff. At the meeting, the inspector reviewed the scope and findings of the inspection, which were acknowledged by facility management present. Facility management stated that concerns identified by the inspector, and not already corrected, would be addressed and corrected. None of the information reviewed during the inspection was identified as being proprietary information.

The inspectors presented the remainder of the integrated inspection results to Mr. B. Tuite and other members of licensee management at the conclusion of the inspection on September 5, 1997. 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.

X3 Management Meeting Summary

On July 31 to August 1, Mr. W. Axelson, NRC Region I Deputy Regional Administrator, Mr. P. Eselgroth, Chief, DRP Branch 7, and Mr. D. Brinkman, NRR Senior Project Manager, conducted plant tours and interviewed site personnel. The NRC management team discussed their observations with plant management at the conclusion of the site visit.

PARTIAL LIST OF PERSONS CONTACTED

DLC

J. Cross, President, Generation Group
R. LeGrand, Vice President, Nuclear Operations/Plant Manager
S. Jain, Vice President, Nuclear Services
K. Ostrowski, Manager, Quality Services Unit
B. Tuite, General Manager, Nuclear Operations
C. Hawley, General Manager, Maintenance Programs Unit
R. Vento, Manager, Health Physics
D. Orndorf, Manager, Chemistry
F. Curl, Manager, Nuclear Construction
J. Matsko, Manager, Outage Management Department
T. Lutkehaus, Manager, Maintenance Planning & Administration
T. McGhee, Coordinator, Onsite Safety Committee
J. Macdonald, Manager, System & Performance Engineering
K. Beatty, General Manager, Nuclear Support Unit
J. Arias, Director, Safety & Licensing
W. Kline, Manager, Nuclear Engineering Department
R. Brosi, Manager, Management Services
O. Arredondo, Manager, Nuclear Procurement

NRC

D. Kern, SRI
G. Dentel, RI
F. Lyon, RI

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 71001:	Licensed Operator Requalification Program Evaluation
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 92700:	Follow-up - Onsite Follow-up, Written Reports of Nonroutine Events
IP 92901:	Follow-up - Operations
IP 92902:	Follow-up - Maintenance/Surveillance
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED AND DISCUSSED

<u>Opened/Closed</u>

50-334 and 412/97-06-01	EEI	Inoperable SLCRS (Section E1.2)
50-334 and 412/97-06-02	NCV	Containment Penetrations Not in Accordance With the Design Basis (Section E8.5)
50-334 and 412/97-06-03	NCV	Containment Piping Supports Not in Accordance With the Design Basis (Section E8.7)

<u>Closed</u>

50-334 and 412/96-07-03	VIO	Failure to Perform Audit of OSC Activities (Section O8.3)
50-334/97-02-10	URI	Acceptability of MSIV Bypass Valve Closure Time (Section E1.1)
50-334/96-06-01	URI	Containment Penetrations Not in Accordance With the Design Basis (Section E8.5)
50-412/97-01	LER	Reactor Trip Due to Main Transformer Ground Protection Relay (Section O8.1)
50-412/97-02	LER	Technical Specification Required Shutdown Due to Missing or Degraded Recirculation Spray System Pump Flood Seals (Section O8.2)
50-412/96-010	LER	Migration of Leak Sealant Material into the Reactor Head Vent System (Section M8.1)
50-334/97-019	LER	Containment Penetration Check Valves Not in Accordance with the Design Basis (Section E8.1)
50-334/97-009	LER	Main Steam Isolation Bypass Valves Do Not Meet Technical Specification Engineered Safety Feature Response Time Requirements (Section E8.4)

50-334/97-005-01	LER	Inadvertent Operation of 345kV Bus Backup Timer Relay Results in Dual Unit Trips (Section O8.4)
50-334/96-009	LER	Containment Penetrations Not in Accordance With the Design Basis (Section E8.6)
50-334/96-009-01	LER	Containment Penetrations Not in Accordance With the Design Basis (Section E8.6)
50-334/96-010	LER	Containment Piping Supports Not in Accordance With the Design Basis (Section E8.7)

<u>Discussed</u>

50-334/97-018	LER	Potential for Spurious Seismically Induced Fire Protection System Activation Affecting Emergency Diesel Generators (Section E8.2)
50-334/97-021	LER	Potential for Seismic Event to Result in Both Trains of Supplementary Leak Collection and Release System to Become Inoperable (Section E8.3)

LIST OF ACRONYMS USED

BCO	Basis for Continued Operation
BVPS	Beaver Valley Power Station
CATS	Commitment Action Tracking System
CFR	Code of Federal Regulations
CO2	Carbon Dioxide
CR	Condition Report
CREBAPS	Control Room Emergency Bottled Air Pressurization System
CREBAS	Control Room Emergency Breathing Air System
DBA	Design Basis Accident
DLC	Duquesne Light Company
EDG	Emergency Diesel Generator
EEI	Escalated Enforcement Item
ERT	Event Review Team
ESF	Engineered Safety Feature
I&C	Instrument & Control
ISEG	Independent Safety Evaluation Group
JPM	Job Performance Measure
LER	Licensee Event Report
MWR	Maintenance Work Request
NCV	Non-Cited Violation
NPDAP	Nuclear Power Division Administrative Procedure
NRC	Nuclear Regulatory Commission
NSRB	Nuclear Safety Review Board
NSS	Nuclear Shift Supervisor
NSSS	Nuclear Steam Supply System
MSIV	Main Steam Isolation Valve
ORC	Offsite Review Committee
OSC	Onsite Safety Committee
OST	Operational Surveillance Test
PDR	Public Document Room
QSP	Quality Service Procedure
QSU	Quality Service Unit
RP&C	Radiological Protection & Control
RWST	Refueling Water Storage Tank
SCBA	Self-Contained Breathing Apparatus
SLCRS	Supplemental Leak Collection and Release System
SPED	System & Performance Engineering Department
TER	Technical Evaluation Report
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VOND	Valve Operating Number Diagram