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REGION I

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Licensee: Duquesne Light Company (DLC)

Facility: Beaver Valley Power Station, Units 1 and 2

Location: Shippingport, Pennsylvania

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EXECUTIVE SUMMARY

Beaver Valley Power Station, Units 1 & 2
NRC Inspection Report 50-334/96-04 & 50-412/96-04

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 7-week period of resident inspection; in addition, it includes the results of announced inspections by regional health physics, security, and engineering specialists.

Operations

- The draindown preceding removal of the Unit 1 reactor vessel head was completed in a deliberate manner with close attention to level indications, good communications between the assistant shift supervisor and operators in the field, and active oversight by operations management. Refueling Senior Reactor Operators (SROs) provided excellent oversight of all refueling activities. Refueling engineers also were instrumental in ensuring these activities were completed safely and unexpected conditions were corrected in an approved and methodical manner (Section O1.1).
- The Unit 1 plant startup received additional management scrutiny and industry experiences were appropriately considered. Plant startup was performed well with proper attention towards safety (Section O1.2).
- The licensee has established a new employee concerns program, the Employee Concerns Resolution (ECR) program. Based on initial performance, the ECR program provides a satisfactory means to identify, receive, document, investigate, and resolve employee concerns while maintaining a high degree of confidentiality. The new ECR program has been more effective than the previous program in providing a means for employees to express concerns (Section O8.1).

Maintenance

- A weakness was identified and corrected in the precautions of a surveillance test, but had no adverse safety consequences. The other maintenance and surveillance activities observed and reviewed were performed safely and in accordance with proper procedures (Sections M1, 2, 3, 5 & 9).
- The air operated valve preventive maintenance program was found to be a good initiative and was providing beneficial results during the Unit 1 outage. A strong licensee commitment towards this program was demonstrated. Maintenance personnel acknowledge that planning and coordination conflicts presented the biggest challenge towards completing the scheduled scope of work. Lessons learned, such as the need to train additional technicians, will be applied to the upcoming Unit 2 outage (Section M1.4).
- A thorough investigation resulted in the identification of a potential generic deficiency associated with the solid state protection system.

Several components, all of which had properly actuated to their safety injection position did not reset. Corrective actions were found to be effective. The licensee has initiated a 10 CFR Part 21 evaluation. Westinghouse is examining this reset issue for generic applicability (Section M1.6).

- Unit 1 river water flow test results were properly evaluated and demonstrated that design changes involving replacing the river water lines to the charging pumps and control room coolers were effective in providing greater flow margins (Section M1.7).

- The licensee's ISI program was effective in identifying an indication in the Unit 1 loop C cold leg. This is considered to be a crack based on careful evaluation of the inspection results and independent NRC inspections. The licensee performed a bounding calculation, in accordance with the code, for continued service of the component. The calculations were submitted to NRC for review and were determined to be appropriate. In accordance with the ASME Code, a rejectable indication must be re-examined during each of the next three 40-month inspection periods (Section M1.9).

- Additional emphasis was placed on housekeeping after housekeeping deficiencies were identified at Unit 2 (Section M2).

- All necessary MWRs which were needed to support Unit 1 equipment operability were worked during the outage. Those items not worked were either technically justified as being acceptable or did not present a potential challenge as an operator work around (Section M3.1).

- Significant improvement has been evident in the procurement support of outage maintenance. No emergent work was deferred due to parts unavailability, and only four maintenance activities were deferred. There was no impact on safety or reliability associated with these four deferred items (Section M8.1).

- An open item involving reactor coolant pump seal maintenance was closed based on the licensee's development of an appropriate technical justification (Section M8.2).

- A previous violation involving an emergency switchgear ventilation fan control circuit deficiency was closed based on correction of the deficiency, improved identification and tracking of maintenance work, and enhanced use of PRA information (Section M8.3).

Engineering

- The IST program was properly testing relief valves in accordance with the ASME requirements. However, the timeliness of resolution of past component cooling water system relief valve failures was slow in that corrective actions were not in place to have mitigated those failures which were identified during the current outage (Section E2.1).

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- The licensee correctly concluded that degraded incore thermocouples remained operable but the basis for this conclusion was not well documented (Section E3.1).

- Pre-job planning for the pressurizer surge line inservice inspection was weak in that it did not timely identify the work scope for access to the inspection location. Also, the licensee's knowledge of the ASME code was incomplete as the NRC identified that an automatic 1-year extension was permitted by the code (Section E4.1).

- The licensee's identification of a stress qualification error from the original design change which installed the reactor head vent system at Unit 1 was indicative of a good questioning attitude and excellent knowledge of ASME III requirements. Corrective actions restored the system to the original design code (Section E4.2).

- DCPs reviewed were well planned and work instructions accounted for redundant train and technical specification required equipment which needed to remain operable (Section E7.2).

- Licensee identified SSFI issues are being tracked to verify completion of corrective actions (Section E1.1).

- EA reviews have been thorough, probing, and have resulted in well-developed findings and recommendations (Section E7.1).

- An EDSFI open item relating to degraded grid relay setpoints was closed (Section E8.1).

- The engineering review of the spent fuel pool hoist malfunction which occurred on March 29, 1996, was excellent, and identified and resolved additional potential problems (Section E2.3).

- The incore thermocouple degradation operability determination was correct, but not well documented (Section 3.1).

Plant Support

- Overall, performance in the radiation protection (RP) area by RP staff was considered to be very good. Radiological controls established during the Unit 1 refueling outage were considered to be judicious. The newly-installed alarming dosimeter and RCA access control system was an improvement to the radiation protection program in that it significantly enhanced the licensee's ability to effectively monitor and control personnel exposures. The outage RP organization was well staffed to meet the outage workload. Quality Assurance oversight of RP was good as shown by the high quality of findings during audits and surveillances. However, radiation worker practices were considered to be weak and a violation of NRC requirements in this regard was cited (Sections R1, R2, R4, R7).

(EXECUTIVE SUMMARY CONTINUED)

- Chemistry procedures properly controlled sampling valve lineups (Section R3.1).

- The licensee's security performance was found to be in compliance with NRC requirements and no safety concerns were identified in the areas inspected. Management support was evident from ongoing upgrades. Audits were thorough and in-depth. Management controls for identifying, resolving, and preventing programmatic problems were effective, and security program plan changes implemented since the last inspection, under the provisions of 10 CFR 50.54(p), did not decrease the effectiveness of the security program. Alarm stations satisfied security plan commitments, security equipment testing was being performed as required in the NRC-approved Physical Security Plan (the Plan) and maintenance of security equipment had been improved since the previous inspection as indicated by a decrease in the backlog of security equipment work requests. Based on inspector observations and discussions with the security training staff, the inspectors determined that the security force members possessed the requisite knowledge to carry out their assigned duties and that the training program was effective. No weaknesses or discrepancies were identified during the inspection (Sections S1, S2, S5,).

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Report Details

Summary of Plant Status

Unit 1 was in cold shutdown for its tenth refueling outage at the beginning of the period. On May 5, reactor coolant system heatup was commenced, and the unit entered Mode 4, hot shutdown. On May 10, reactor startup commenced and the unit achieved critical operation. The refueling outage officially ended on May 12 when the main unit generator was synchronized to the grid.

Unit 2 operated at full power throughout the inspection period except for a planned load reduction to 50% power from April 4 to 8 for fuel conservation.

I. Operations (71707, 40500)

O1 Conduct of Operations[1]

O1.1 General Comments

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 Refueling Activities (Unit 1)

a. Inspection Scope (71707)

The inspectors observed the refueling activities associated with the Unit 1 outage. The scope of the observations included reactor vessel head removal, upper internals removal, core offload, and core reload. Activities associated with the lower internals removal are discussed in Section R1.1. The inspectors also reviewed the sequence of events and root cause analysis of reactive issues associated with fuel handling.

b. Observations and Findings

The draindown preceding the reactor vessel head removal was completed in a very deliberate manner with close attention to level indications, good communications between the assistant shift supervisor and operators in the field, and active oversight by operations management. Communications within the control room were less formal during the refueling outage than it had been before. For example, during this evolution, repeat backs were done only sporadically. The reactor vessel disassembly was cautiously controlled by the refueling engineers. The pre-evolution briefings were thorough such that personnel involved with the head removal and upper internals removal understood fully their understood duties and responsibilities . These evolutions were completed without complication or incident. The core offload and reload were also well

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[1]Topical headings such as 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.

controlled by the refueling senior reactor operator (SRO). The refueling SRO presence as the "man in charge" was evident to all appropriate personnel. Control and responsibilities were not relinquished to the Westinghouse contract personnel. The inspectors interviewed the SROs and determined that their knowledge level of the refueling operations, pre-requisites, and precautions was excellent. Senior licensee management also maintained a presence during refueling activities via their field observations. Additionally, the General Manager of Operations and the Plant Manager personally briefed the refueling crews at the beginning of the outage so that management expectations were fully understood.

The following incident illustrates a proper "all stop" approach when an unexpected complication arose: A new, un-irradiated fuel assembly was potentially damaged on March 29 during fuel transfer activities within the spent fuel pool. Refueling personnel were preparing to move the new fuel assembly from its storage position in the new fuel elevator to a fuel rack location. The fuel assembly was in the "lowered" position in the elevator. A failure of the crane hoist drive control system occurred while the fuel handling tool was positioned about 4 inches above the fuel assembly. This failure drove the fuel handling tool onto the top of the fuel assembly. The operator was able to terminate the downward movement via the hoist control emergency stop pushbutton. Refueling personnel on the scene properly contacted supervision for assistance prior to taking any corrective action. The fuel handling tool and hoist block assembly were physically secured to prevent any further movement. A procedure was developed and approved to correct the situation in an approved and deliberate manner. There was no apparent damage to any spent fuel assemblies. The new assembly was returned to Westinghouse for inspection and was subsequently deemed acceptable for use. The cause of the hoist failure and corrective actions are discussed in Section E2.3.

c. Conclusions

Overall, the inspectors found that refueling SROs provided excellent oversight of all refueling activities. Refueling engineers also were instrumental in ensuring these activities were completed safely and unexpected conditions were corrected in all approved and methodical manner.

O1.3 Mode Change and Startup Observations (Unit 1)

The inspectors observed the plant heatup and reactor startup activities at the conclusion of the outage. The inspectors also verified that selected mode change pre-requisites were satisfied. The plant heatup and startup were well controlled by the shift supervisors. Operational surveillance tests were properly completed to support system operability prior to each mode change. The reactor startup was designated as an "Infrequently Performed Test or Evolution;" and thus received additional management attention and scrutiny. Industry lessons learned were discussed at the pre-evolution briefing in order to raise the awareness of operators to potential pitfalls. The approach to criticality was cautiously controlled as operators appropriately monitored the reactivity changes. The inspectors concluded that the overall plant startup was performed well with proper attention towards safety.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdowns

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 Residual Heat Removal System
- Unit 1 Component Cooling Water System
- Unit 1 Emergency Diesel Generator Fuel Oil
- Unit 1 Fuel Pool Cooling
- Unit 1 Supplemental Leakage Collection and Release
- Unit 2 Auxiliary Feedwater System
- Unit 2 Service Water System

O8 Miscellaneous Operations Issues

O8.1 New Employee Concern Resolution Program and Former Quality Concern Resolution Program

a. Inspection Scope

During this inspection period, the licensee completed establishing their Employee Concern Resolution (ECR) Program and discontinued their Quality Concern Resolution Program (QCRP). The inspectors reviewed ECR program procedures, interviewed the site Ombudsman who is responsible for implementing the ECR program, and reviewed the handling of several concerns by the ECR program. The inspectors also reviewed the closeout of the QCRP including the closeout of the last concern handled by the QCRP. The inspectors performed these reviews to determine if employee concerns were being satisfactorily handled and resolved.

b. Observations and Findings

The licensee's Nuclear Power Division Directive 1.8.8, "Employee Concern Resolution Program", Revision 4, effective 3/29/96, and Nuclear Power Division Administrative Procedure 8.14, "Employee Concern Resolution (ECR) Program", Revision 3, effective 4/25/96, established the ECR program and the site Ombudsman position. Initial steps were taken to advertise the ECR program and the Ombudsman function through the Unit 1 refueling outage handbook, through the Beaver Valley site newsletter, by the active presence of the site Ombudsman, and by replacing QCRP posters and receipt forms throughout the site with new ones describing the ECR program and site Ombudsman. In addition, employees will be informed about the ECR program and site Ombudsman function through general employee training and retraining.

The previous program, the QCRP, was rarely used. The QCRP received only one concern since the end of 1994. In contrast to this, the Ombudsman has been receiving several concerns per month. The inspectors credited this to the effectiveness of the new program rather than to a decline in licensee performance or morale. Some of these concerns were by walk-in visits which indicates effective advertisement of the program. Some concerns were identified by departing employees and some departing employees made positive comments about the licensee. The Ombudsman conducts exit interviews of some employees and exit interview forms are made available to all departing employees. A 24-hour hotline has been established for the ECR program as was done for the QCRP. All comments and concerns were treated with a high degree of confidentiality.

The inspectors found no issues with safety consequences among the concerns received by the concerns programs. Based on a sample of concerns received by the ECR program, the inspectors found that investigations were of appropriate scope and depth and that the findings were being followed up in a timely manner.

The inspectors reviewed the last issue handled by QCRP and concluded that the QCRP had handled this issue properly, conducted an investigation of appropriate scope and depth, and that the actions taken to resolve the issue were satisfactory. QCRP performed an audit on March 15, 1996 and verified that corrective actions for the last open item from the last concern handled by QCRP were complete prior to turnover of QCRP activities to the Ombudsman.

c. Conclusions

Based on initial performance, the ECR program provides a satisfactory means to identify, receive, document, investigate, and resolve employee concerns while maintaining a high degree of confidentiality. The new ECR program has been more effective than the previous program in providing a means for employees to express concerns.

II. Maintenance (62703, 61726, 57080)

M1 Conduct of Maintenance

M1.1 Routine Maintenance Observations

The inspectors observed selected maintenance activities on important systems and components. The maintenance work requests (MWRs) and maintenance surveillance procedures (MSPs) activities observed and reviewed are listed below.

- MWR 050601: Emergency diesel generator turbocharger replacement (Section M1.5)

- MWR 052635: Solid state protection system troubleshooting (Section M1.6)
- MWR 052705: Solid state protection system troubleshooting (Section M1.6)
- MWR 052717: Solid state protection system troubleshooting (Section M1.6)
- MWR 052716: Solid state protection system troubleshooting (Section M1.6)
- MWR 043079: Inspect motor/breaker for recirculation spray pump (2RSS-P21C)
- MWR 050382: Troubleshoot/repair position indication for 2LMS-SOV951
- MWR 044317: Pressurizer relief valve reassembly (RV-RC-551A)
- MWR 029125: REJ-RW-26R1 replacement
- MSP 2-1.05: Solid state protection system train B bi-monthly test
- MSP 36.72M: Diesel fuel injector testing

The activities observed and reviews were performed 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.

M1.2 Routine Surveillance Observations (61726)

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

- 1OST 30.12B River Water Full Flow Testing (Section M1.7)
- 1OST 11.14 Safety Injection Full Flow Testing (Section M1.8)
- 1OST 36.4 Diesel Generator No. 2 Automatic Test
- 2OST 36.1 Emergency Diesel Generator (2EGS-EG2-1) Monthly Test
- 2OST 13.1 Quench Spray Pump (2QSS-P21A) Test
- 2OST 24.2 Motor Driven Auxiliary Feed Pump (2FWE-P23A) Test
- 2OST 36.2 Emergency Diesel Generator (2EGS-EG2-2) Monthly Test
- 2OST 1.11D Safeguard Protection System Train A CIA Go Test
- 2OST 24.4 Steam Turbine Driven AFW Pump (2FWE-P22) Monthly Test (Section M1.3)

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 and difficulty.

M1.3 Premature Start of Unit 2 AFW Pump Turbine During OST

While observing preparations to conduct a warm start of Unit 2 auxiliary feedwater pump 2FWE-P22 in accordance with 2OST 24.4, the inspectors noted that the turbine started prematurely when 2MSS-17, the turbine steam supply isolation valve, was opened. Because the pump discharge valve was still locked open at that point of the procedure, the potential existed to adversely affect reactivity by inadvertently injecting cold feedwater into the steam generator. The control room operator isolated the steam supply to the turbine before water could be injected.

2MSS-17 is normally locked open; however, since December 1995 it has been shut and controlled by a Special Operation Order and Nuclear Shift Supervisor (NSS) Operating Clearance (tag). The valve was shut to prevent further degradation of downstream steamline solenoid operated isolation valve, 2MSS-SOV105C, which is leaking by. When 2MSS-17 was opened, downstream SOVs 105C and 105F fluttered open and admitted steam to the turbine. There is no control room alarm to warn the operator that the SOVs have opened, but there is valve position indication for the SOVs on the control board. Operators performing the OST were aware beforehand of the potential for the SOVs to open, and the SOVs were shut by the control room operator before the pump discharge pressure exceeded steam generator pressure and feedwater was injected. There were no adverse safety consequences.

The initial conditions, precautions and limitations, and test preparation sections of the OST did not mention the degraded SOVs or the need to open 2MSS-17 to establish conditions to run the test. The inspectors considered the omission to be a procedural weakness. The issue was discussed with the operations staff. Operators submitted a problem report to document the issue and an operating manual change request to strengthen the OST procedure. The inspectors concluded that the issue was adequately addressed.

M1.4 Air Operated Valve Maintenance

a. Inspection Scope

The inspectors reviewed the licensee air operated valve (AOV) preventive maintenance (PM) program as documented in Maintenance Program Unit Procedure 4.26. Additionally, the inspectors observed valve testing for TV-CC-110E3 (MWR 051275) and TV-CC-111D2 (MWR 028492).

b. Observations and Findings

The AOV PM program was initiated in response to industry experience and draft ASME guidelines for AOV maintenance. There are no current regulatory requirements for such a program. The 167 Unit 1 valves within the program scope include risk significant valves and those which receive an emergency safeguards feature actuation signal. The inspectors identified that TV-CC-137A and B (component cooling water outlet isolation valves from the refueling water storage tank refrigeration units) were omitted from the program scope. These valves receive a containment isolation signal phase A. This omission has since been corrected. Valve testing was conducted in accordance with procedure 1/2PMP-75-AirCet-1I. The inspectors found the technicians to be well versed in the testing methodology, and good vendor support was provided in the data analysis. Beneficial information was gleaned from the test results, such as the identification of a faulty positioner for charging flow control valve FCV-CH-122. Additional beneficial information includes baseline data for evaluation of future potential degradation. Maintenance personnel were able to overcome initial planning and coordination challenges by applying lessons learned from the motor operated valve testing program, such as convening a daily AOV working group. In all, approximately 52 AOVs were worked on by maintenance personnel during the Unit 1 refueling outage, with only one deferral. This deferral was technically justified as there were no performance problems associated with this valve. The inspectors did note a greater commitment to completing the scheduled AOV activities when compared to last outage.

c. Conclusions

Overall, the inspectors found the AOV program to be a good initiative that was providing beneficial results. A strong licensee commitment towards this program was demonstrated. Maintenance personnel acknowledge that planning and coordination conflicts presented the biggest challenge towards completing the scheduled scope of work. Lessons learned, such as the need to train additional technicians, will be applied to the upcoming Unit 2 outage.

M1.5 Unit 1 Emergency Diesel Generator Turbocharger Replacement (MWR 050601)

The inspectors observed the replacement of the turbocharger for the Unit 1 emergency diesel generator. This replacement was necessitated by the fact that the "end thrust" was only 0.001 inches within specification. The corrective maintenance procedure was well detailed to support the maintenance activity. The acceptance criteria for "impeller eye clearance" and "end thrust" were consistent with the technical manual. Good technical support was provided by licensee engineering personnel and the vendor representative. Technical Evaluation Report (TER) 10174 properly evaluated the replacement turbocharger as a one for one replacement. A root cause analysis is planned to determine why minimal margin existed for the turbo charger given the relatively low number of run hours for the engine. Overall, the inspectors concluded that the turbocharger replacement was completed properly by well skilled mechanics.

M1.6 Unit 1 Solid State Protection System Troubleshooting (MWRs 052635, 052705, 052717, 052716)

a. Inspection Scope

The inspectors observed and reviewed the licensee actions to resolve a deficiency identified with the Unit 1 solid state protection system (SSPS). Following the No. 1 emergency diesel generator auto load safety injection test, the licensee identified that several components could not be reset to their presafety injection position after the operation of the manual safety injection reset pushbutton. These include, for example, safety injection accumulator discharge isolation valve MOV-SI-

865A, charging pump isolation valve MOV-CH-115C from the volume control tank, and charging header isolation valve MOV-CH-289. These components all properly actuated to their safety injection position as required.

b. Observations and Findings

Investigation and troubleshooting by maintenance engineers identified that all these components were associated with slave relays K603A and K601A. Testing revealed that these relays were properly functioning. However, the investigation identified that a "relay race" was responsible for de-energizing the unlatch coils (i.e., reset relays) too quickly. This results in the slave relays remaining latched and thus maintaining the above mechanical components in their respective safety injection position. Testing of the 'B' train revealed this same problem and confirmed that a relay race was responsible. Consultation with Westinghouse SSPS design engineers validated the licensee's findings. With the concurrence of Westinghouse, a design change (TER 010333) was implemented which slowed down the operation of the unlatch function by 3 cycles to allow the relays to perform their reset function before they are de-energized. The inspectors reviewed the design change and the post modification testing which demonstrated satisfactory and repeatable results. This deficiency has not previously occurred at Unit 2, however; the licensee appropriately plans on performing similar testing during the upcoming refueling outage.

c. Conclusions

Overall, a thorough investigation resulted in the identification of a potential generic deficiency associated with SSPS. The licensee has initiated a 10 CFR Part 21 evaluation. Corrective actions were found to be effective. Westinghouse representatives have stated that this reset issue is being examined as a "potential issue" for further review of generic applicability.

M1.7 Unit 1 River Water Full Flow Testing 1OST 30.12B

The inspectors observed the river water full flow testing at the beginning and end of the outage. A comparison of the as-found testing and as-left testing results was completed to allow an assessment of design changes associated with this system. Two major design changes included the replacement of the river water piping to the charging pump coolers and the control room cooling coils. Internal piping corrosion has degraded system performance and necessitated the replacement with a stainless steel alloy. The as-found testing identified that flow to the control room cooling coils (99 gpm) was below the acceptance criteria of 107.7 gpm. This discrepancy was properly evaluated and deemed acceptable based upon the fact that river water temperature during the past operating cycle was 4°F less than the 90°F assumed for design basis accident conditions. Thus, a lower river water flow of 72 gpm was the minimum required flow to demonstrate operability for the past cycle. After completion of the design changes, increased river water flow to the charging pumps provided additional margin. Additionally, river water flow from the control room cooling coils increased from 99 gpm to 231 gpm. Overall, the inspectors found that test results were properly evaluated and that the design changes were effective in providing greater margins of flow for the charging pumps and cooling coils.

M1.8 Unit 1 Safety Injection Full Flow Testing 1OST 11.14

The inspectors observed the full flow testing of the low head safety injection system. A reactor operator currently in the SRO training program was designated as the responsible test coordinator for this evolution. This test was well conducted and coordinated as operators properly balanced injection flow with residual heat removal return to the refueling water storage tank in order to maintain proper reactor coolant water inventory. Utilization of the reactor operator/SRO trainee allowed the on-shift Nuclear Shift Supervisor to maintain an overview on the entire evolution and its potential impact on the plant. Overall, the inspectors found the testing to be effectively performed with good use of available resources to alleviate the work load of the shift supervisor.

M1.9 Unit 1 Recirculation Loop Piping UT Inspection

a. Inspection Scope

During refueling outage 11 (RFO11) inservice inspection (ISI) at Beaver Valley, Unit 1, the DLC ultrasonic Level III inspector detected a linear ultrasonic (UT) indication in a reactor coolant system (RCS) loop piping weld. The weld joins A351, CFM8 centrifugally cast pipe to a statically cast elbow. This weld is the third joint from the reactor vessel.

The NRC performed an independent ultrasonic examination of weld DLW-LOOP3-7-S-02, to verify the findings of DLC and characterize the UT indication.

b. Observation and Findings

The UT indication was evaluated by the NRC using a series of different techniques and equipment. The first technique was a 0° longitudinal examination to identify changes in velocity or signal response from the indication. The 0° examination showed several velocity changes. The velocity changes were in the elbow, weld, and pipe material. The back wall signal increased from 80% FSH to 120% FSH in the area of concern, 85" to 88", and the signal shifted to the left on the base line. The signal change indicates a velocity change or large reflector. This signal change was only present 85"-88" of the examination area.

The NRC inspectors used a variety of transducers and instruments in the area of interest. This was to identify any transducer or machine anomalies. The transducers were all 45°, refracted longitudinal wave, sizes of .5" to 1", frequencies of .5 MHz and 1 MHz, with focal depths of 1.5", 3", and one unfocused transducer. The indication produced a signal response from all of the transducers, except the transducer focused at 1.5" depth. The transducers were used with both a Sonic 136 and a Panametrics EPOCH II UT instrument. No unexpected anomalies were noted. The indication was also verified using DLC's equipment and the calibration used to first detect the indication.

The next technique used was 45° thru-transmission. The thru-transmission technique used was to determine if the indication was connected to the inside diameter (ID). The transducers (45°, 1MHz) were placed on opposite sides of the weld, one to transmit and one to receive. The signal response on the calibration block was set to 80% FSH on the UT instrument. The transducers were then moved circumferentially on the pipe. There was little change in the signal amplitude. An ID connected indication would cause a decrease in the signal amplitude. This technique was applied to characterize the indication, not for detection of the indication. Although the indication appeared not to be ID connected, the inspectors did not rule out the possibility of a crack based on this technique.

DLC performed enhanced visual and eddy current examination from the ID of the pipe to identify any ID connected indications and geometric conditions. The results of the examinations revealed no extraordinary geometric conditions nor visual or eddy current indications. The construction radiographs were reviewed for existing acceptable construction defects. No defects were noted. Previous pre-service inspection (PSI) and ISI UT data was also reviewed for previous indications. No recordable indications were noted for those exams. Therefore, the indication is new and was not noted on previous exams.

c. Conclusions

After careful evaluation of the inspection results by the NRC, the UT indication in DLW-LOOP3-7-S-02 is considered to be a crack. This is based on the fact the indication was not detected previously, strong signal response from a 45°RL, the signal remains thru a 20° transducer skew, the signal is only in a single location, and is repeatable with different transducers and equipment. The crack measurements are 2.5" in circumferential length, approximately 1" thru wall, located 86.5" from TDC.

In accordance with ASME Code, Section XI, IWB-2420, 1983 edition, a rejectable indication must be re-examined during each of the next three 40-month inspection periods. DLC has performed a bounding calculation, in accordance with ASME Section XI, IWB-3640, 1989 edition, for continued service of the component. The calculations were submitted to NRC for review and determined to be appropriate for the purpose as documented in NRC's May 1, 1996 safety evaluation.

M2 Maintenance and Material Condition of Facilities and Equipment

During tours of the Unit 2 auxiliary building radiologically controlled areas (RCAs), inspectors noted numerous cigarette butts, and occasional candy wrappers and recreational reading material, on all levels of the building on the floor, behind breakers, in openings in structural members, and under equipment platforms of both safety-related and non-safety-related equipment. In addition, some loose tools such as screwdrivers, wrenches, and a drop light were noted. Some of the trash was evidently several years old, while some was more recent. These indicated longstanding problems with inadequate housekeeping and a lack of adherence to the prohibition on eating and smoking in the RCA. The prohibition on eating, chewing, and smoking in the RCA was previously reinforced in a notice promulgated in 1994 from the Plant Manager regarding unacceptable radiation worker practices; however, the notice was apparently less than fully effective. Inspectors discussed the issue with the Plant Manager and health physics staff, who agreed that additional emphasis in the area was required.

M3 Maintenance Procedures and Documentation

M3.1 Post Outage Maintenance Review

The inspectors reviewed all MWRs which were eliminated from the original work scope. The inspectors also reviewed all emergent MWRs generated during the Unit 1 outage. The purpose of this review was to assess if any items not worked during the outage could represent a potential operability concern or operator work-around when the unit returned to power operation. A post outage goal is 100 days of power operation and no reactor trips which result from any maintenance activity worked during outage or a maintenance activity that should have been worked. Deferments involving parts availability is discussed in section M8.1.

Items deferred from the pre-outage scope require the approval from the responsible department mangers and the Plant Manager. The inspectors did not identify any deferred MWRs which needed to be addressed during the current outage. Some deferrals involved contingency work such as valve re-packing or potential type 'C' valve failures which where later inspected/tested and found to be satisfactory. Technical justifications were appropriately developed as needed for the deferrals. For example, engineering evaluations allowed the licensee to defer replacement of the rotating assemblies for the motor driven auxiliary feedwater pump and quench spray pump until the next refueling outage. The potential deferral of some maintenance due to high radiation fields was not permitted. For example , the replacement of three snubbers was not rescheduled since their seal life could not be further extended. Of the 920 emergent work items written during the outage, the inspectors did not identify any MWRs that were inappropriately deferred to the next outage or the 12 week non-outage schedule. Voided MWRs were either duplicates or technically justified following acceptable performance testing.

Overall, the inspectors concluded that all necessary MWRs which were needed to support equipment operability were worked during the outage.

Those items not worked were either technically justified as being acceptable or did not present a potential challenge as an operator work around.

M8 Miscellaneous Maintenance Issues

M8.1 Procurement Support of Unit 1 Outage Maintenance

a. Inspection Scope

The inspectors reviewed procurement performance indicators and outage schedule change requests in order to assess the availability of parts for outage maintenance. Past procurement support has been identified by the licensee as needing improvement.

b. Observations and Findings

Performance indicators show that procurement organization has made progress in correcting receipt discrepancies of safety related components. These discrepancies could include either an actual part material problem or a paperwork problem identified upon receipt of the part. The percentage of receipt discrepancies has decreased from 31% to 16% over the last 5 months. Progress has also been evident in reducing the backlog of "repeat cards." These are outstanding orders for repetitive use items which are out of stock. The backlog of material requisitions (orders for non-repeat items) has also decreased, although a recent stagnation was evident since January 1996. The current backlog of material requisitions is well above the licensee's goal and is a reflection of the continuing need to match warehouse inventory with actual plant needs.

During daily outage management meetings, the inspectors have observed a greater emphasis on not deferring any maintenance due to parts unavailability. On a daily basis, procurement management met with representatives with of the various maintenance groups to ensure there were no short-term emergent issues which needed immediate procurement support, or if any parts currently on order would not satisfy the maintenance start date. Support of emergent work identified during the outage was excellent as no emergent MWRs were deferred due to parts unavailability. With respect to pre-scheduled outage maintenance, the procurement department had a goal of zero scheduled maintenance deferrals due to parts unavailability. This goal was, however, not satisfied as illustrated by the following two examples:

- MWRs 27933 and 27929 involved the replacement of 480V safety-related breakers with refurbished spares per the preventive maintenance (PM) program. These items were deferred because the replacement breakers did not arrive with sufficient lead time for electricians to perform the necessary pre-installation checks. These parts were not being tracked as needed for outage support, even though the maintenance was designated for the current outage. Also, procurement management was not informed in advance that the delivery date would not support the maintenance. There were no safety implications in deferring this maintenance because there are no performance concerns with the installed breakers, and the actual PMs are not due until January 1998.

- MWRs 42410 and 42414 involved preventive maintenance inspections of diesel generator relays. This scheduled maintenance was deferred due to replacement relays not being available. The vendor had informed the procurement engineer that the order was complete; however, this had not been verified as being accurate. Also, procurement management was not informed of this deferral until 2 weeks after the outage schedule change request was approved by outage management. Procurement was subsequently able to obtain the necessary relays within 24 hours; however, this was after the diesel maintenance window was closed. There were no safety implications in deferring this maintenance because there are no performance concerns with these relays.

The inspectors also discussed with the procurement manager that outage schedule change requests involving parts support do not require his prior approval. A procedural change has been initiated to require procurement approval for such maintenance deferrals. A root cause analysis is underway by the Independent Safety Evaluation Group to examine the communication and the pre-outage planning issues.

c. Conclusions

Overall, the inspectors found that significant improvement has been evident in the procurement support of outage maintenance. No emergent work was deferred due to parts unavailability, and only four maintenance activities were deferred out of a total outage scope of 1078 maintenance work requests (approximately 0.4%). There was no impact on safety or reliability associated with these four deferred items. Continuing efforts are underway to further strengthen communication and planning between the line organization and the procurement department.

M8.2 (Closed) Follow-Up Item 50-334/412 95-13-02: Reactor Coolant Pump (RCP) Seal Maintenance. This item was opened due to the licensee's lack of technical justification for deviation from vendor guidance for RCP seal inspections. For model 93-A RCPs, Westinghouse currently recommends an inspection frequency of 24,000 hours of pump operation to coincide with an 18-month fuel cycle. For a three loop plant, this correlates to two seal inspections in a refueling outage, and the third in the subsequent refueling outage. Unit 1 seal inspection practices are consistent with this guidance. Unit 2 performs RCP seal inspections on a 54 month or 36,000 hours of operation frequency. This has since been technically justified by the licensee based on past seal inspections and performance. The inspectors reviewed these reports which indicates that the number 1, 2, and 3 seal runners and rings have been found in a good condition. Additionally, the graphitar nose height for the number two and three seals have consistently been well above the acceptance criteria and were acceptable for re-use. The licensee has also performed various seal upgrades as recommended by the vendor. Also, high temperature O-rings have been approved for use at both units to address the higher RCS temperature associated with station blackout conditions. This upgrade was completed for one of the Unit 1 RCPs and is scheduled to coincide with future scheduled seal maintenance for the remaining RCPs at both units. This item is closed based on the licensee's development of a performance based technical justification.

M8.3 (Closed) Violation 50-412/94-25-01: This violation involved the failure to identify and correct a control circuitry deficiency that could prevent the emergency switchgear ventilation fan 2HVZ-FN261A from auto starting in the standby mode under certain conditions. Also involved in this deficiency was the licensee's lack of usage of probablistic risk assessment information in the maintenance process. This violation is closed based on the following:

- Design change 2124 has corrected the particular deficiency with the control circuit. Post modification testing has verified the effectiveness of this corrective action.
- The licensee has initiated a process, as part of the maintenance rule, to identify and track MWRs in which "no failure" is identified. Thus, if multiple MWRs are written for a specific deficiency even if no failure is consistently identified, this would indicate that the MWR corrective actions were not effective and that additional investigation is necessary. This issue was previously documented in NRC inspection report 50-412/95-16
- Enhanced use of PRA information has been evident in licensee actions such as with the river water rubber expansion joint replacement (see NRC inspection report 50-334/95-21) and on-line maintenance practices (see NRC Inspection report 50-334/96-03).

The inspectors concluded that the licensee corrective actions have been appropriate.

III. Engineering (37552, 37550)

E1 Conduct of Engineering

E1.1 Safety System Functional Inspection (SSFI) Followup

a. Inspection Scope

The inspectors reviewed the Duquesne Light Co. (DLC) report of the results of the DLC-conducted SSFI conducted on the Unit 1 Safety Injection System in November 1995. The inspectors also reviewed several problem reports, written to address findings of the evaluation team, to determine how DLC is addressing the team's findings in the long term. The problem reports reviewed are listed in Appendix X.

b. Findings and Observations

Several of the unresolved issues from the SSFI related to the adequacy of surveillance testing of the logic relay trains. The mechanical latching functions of several relays were not being verified in the routine surveillances. The inspectors reviewed procedures for monthly SI logic system surveillances and the monthly maintenance checks of the solid state protection system (SSPS), and determined that the latching of the relays has been verified during the SSPS monthly testing. DLC is revising the monthly SI logic functional surveillance test to verify the latching of the relays.

The logic relay test issues resulted in the issuance of problem reports (PRs) 1-95-554 and 1-95-555. Initial review of these PRs by the operating experience group resulted in a determination of "not reportable." Further review by DLC of the 18-month surveillance procedure and the logic testing requirements has resulted in a reevaluation and a determination by DLC that the issue is, in fact, reportable. At the end of the inspection, DLC was preparing an LER to document the matter.

c. Conclusions

The inspectors concluded, based on the specific issues reviewed during this inspection, that appropriate corrective actions were being implemented for the discrepancies identified by the DLC SSFI team, and that the unresolved issues are being tracked to verify completion of the evaluations and analyses.

E2 Engineering Support of Facilities and Equipment

E2.1 Inservice Testing (IST) of Unit 1 Relief Valves

a. Inspection Scope

The inspectors reviewed the results of inservice testing of relief valves for the component cooling water (CCR) system. This review followed the reporting of a high percentage of failures during scheduled testing.

b. Observations and Findings

Relief valves are tested in accordance with ASME requirements at least every 5 years. A failure is defined as a valve with any of the three "as found" setpoint readings greater than the valve's listed setpoint pressure. Following each valve failure in the CCR system, the inspectors verified that the inspection scope was properly expanded per program requirements. However, the number of failures became so numerous that eventually, all CCR Unit 1 relief valves required testing. In total, 21 out of 60 safety related relief valves failed to lift within 10% of the acceptance criteria. These include CCR relief valves for the reactor coolant pump thermal barrier, a residual heat removal heat exchanger, and a non-regenerative heat exchanger. The licensee has attributed these failures to iron oxide buildup on the valve seating surfaces. This residue acts as a sticking agent which results in higher break away as found lift pressures. The licensee has attributed this residue to oxygen depletion in stagnate lines. The component cooling water system currently uses a molybdate based corrosion inhibitor. This additive requires oxygen to effectively act as a corrosion inhibitor. An engineering evaluation has been completed to allow the addition of a nitrite chemical inhibitor in combination with molybdates to reduce the corrosion rate of carbon steel. The chemistry department has since these initiated chemical additions. The inspectors noted that the licensee is currently aggressively pursuing resolution of this issue; however, the problem of corrosion product buildup was first identified in late 1994 and resulted in the generation of a problem report open item (dated December 15, 1994). During the tenth refueling outage at Unit 1, 17 relief valves failed their inservice testing due to this corrosion product buildup.

c. Conclusions

Overall, the inspectors concluded that the IST program was properly testing relief valves in accordance with the ASME requirements. However, the timeliness of resolution of past relief valve failures was slow in that corrective actions were not in place to have mitigated those failures which were identified during the current outage.

E2.2 Modifications

a. Inspection Scope

The inspectors reviewed the installation instructions for several modifications to safety-related equipment scheduled for implementation during the Unit 1 refueling and maintenance outage. Where available, the inspectors reviewed work packages provided to the field, observed field activities related to the installation of the modifications, and discussed the progress of the work with installation and quality services personnel. In addition, the inspectors reviewed approved changes to the modifications to determine if they were issued in order to complete the work packages, correct errors, or compensate for unanticipated conditions in the field. The modifications selected were:

- D2163 - Freeze Protection for AFW Piping
- D2097 - SSW-VITBUS-1(2) MCCB Replacement
- D2151 - Replacement and Reroute of the River Water Supply and Return Lines to the Charging Pump Lube Oil Coolers, CH-E-7A,B
- D2161 - Reactor Head Support System Mods
- D2173 - Upgrade of River Water Piping to the Unit 1 Control Room Ventilation Equipment (VS-P-3A,B and VS-E-14A,B)

The change documents reviewed are listed an Appendix X.

b. Observations and Findings

A change to the engineering organization eliminated the field engineering group, and distributed those personnel throughout the rest of the nuclear engineering department organization. This has necessitated, among other things, a change to the way in which Field Change Notices (FCNs) are handled. Formerly, FCNs were originated by field engineering personnel and evaluated/approved by design engineering personnel, and they are now generated by field installation personnel (pipefitters, electricians, mechanics, etc.). Evaluation and approval are still the responsibility of the design engineering organization. Engineering Change Notices (ECNs) are still strictly an engineering department product. In addition, a change to the design control system [the use of controlled Installation and Test Plans (I&TPs) for the installation of modifications] has resulted in the installation data sheets being part of the controlled design output. This, in turn, has resulted in the need for issuance of ECNs/FCNs to change information on installation data sheets (and therefore, more ECNs/FCNs).

The I&TPs for several of the modifications specifically called out coordinating work with another DCP to ensure that equipment in redundant trains were not taken out of service at the same time. In addition, the river water piping replacement DCPs constructed a temporary enclosure to maintain the control room ventilation boundary intact during the removal and installation of the piping.

Of the 54 change packages issued against the selected DCPs, only 5 addressed errors or omissions in previous engineering output documents. 52 of the change packages were issued to resolve unanticipated field interferences and/or disassemble and reassemble equipment not included in the scope of the DCP to provide access for the installation of the DCP. All of the EMs reviewed were initiated for evaluation of the acceptability of field conditions or procured components.

Discussions with installation personnel in the field revealed that the installations were going very smoothly. In those instances where interference or accessibility problems to make field welds were anticipated, extra length had been left on the prefabricated spoolpieces in order that the installation personnel could make the connections where convenient. The dimensions were to then be fed back to design engineering, in order that the locations could be marked on the as-built drawings. Some of the interferences (air system lines, conduits, lighting fixtures, components in other systems, etc.) were not obvious during the pre-issue and constructability walkdowns, and only became apparent when the prefabricated spoolpieces were positioned for installation.

c. Conclusions

Based on the number and nature of the changes, and discussions with the installation personnel, the inspectors concluded that the design outputs from engineering were of good quality, and readily support fabrication and field installation. The design process appropriately considered operational requirements of the facility (such as technical specifications and redundant system availability) which must be met during the installation phase of the modification.

E2.3 Spent Fuel Hoist Malfunction

a. Scope of Inspection

The inspectors reviewed problem reports, technical evaluation reports and night order entries related to the malfunction of the spent fuel hoist which occurred on March 29, 1996. Documents reviewed are listed in Appendix X.

b. Observations and Findings

On March 29, 1996, a malfunction of the spent fuel hoist in the fuel handling building occurred. Initial observations by DLC personnel were that the hoist block fell free on the cables, allowing the fuel handling tool to impact a new, unirradiated, fuel assembly which was being prepared for movement. Subsequent troubleshooting determined that a power supply card in the hoist control circuitry had failed, causing the hoist to lower at its maximum speed of 21 feet per minute. This failure was confirmed, and its result verified, in subsequent testing. The hoist operator stopped the hoist motion using the emergency stop push button.

Duquesne Light Company (DLC) personnel working on resolving the issue noted that the particular failure could cause a shift to maximum speed in either direction of travel, up or down. The engineers further determined that this failure could cause the upward travel limit switch to fail to stop the motion of the hoist. Further review of a failure of a relay in the control circuitry which occurred on April 3, 1996, found a history of failures of the relay going back as far as 1982.

The control circuit was modified under two technical evaluation reports. The changes removed (abandoned in place) the motor braking function, which had become unreliable, and rewired the control circuit to put the upward travel limit switch ahead of the upward motion contactor. These modifications were appropriately conducted under the Equivalency Evaluation function of the Technical Evaluation Report process.

c. Conclusions

DLC engineering performed an excellent review of the spent fuel hoist malfunction which occurred on March 29, 1996. The review not only identified the cause of the observed problem, but went on to determine if there were peculiarities in the control circuit which could have caused this failure to have different results. Potential problems were identified, and proactive measures to preclude future occurrence of those problems were implemented. No significant safety issue exists due to the fact that the emergency stop pushbutton would stop travel in either direction (and was in fact used during the March 29 event), and the design of the spent fuel handling tools is such that an irradiated fuel assembly cannot be lifted to within 8 feet 4 inches of the pool surface.

E3 Engineering Procedures and Documentation

E3.1 Incore Thermocouple Degradation

a. Inspection Scope

The inspectors reviewed the licensee's assessment of Westinghouse Nuclear Safety Advisory Letter (NSAL) 95-06, "Incore Thermocouple Moisture Intrusion."

b. Observations and Findings

Insulation resistance (IR) measurements of incore thermocouples have resulted in the identification of moisture intrusion at two other nuclear power plants. Low voltage thermocouple systems can tolerate low IR and still perform their intended function. However, when the thermocouple is subject to rapidly increasing post-accident temperatures, flashing of the trapped moisture can result in damage to the thermocouple. A minimum IR value of 1.0 E6 ohms has been specified by Westinghouse, and initial measurements by the licensee indicated that 40 out of 50 thermocouples were not within specification. Evaluation of the data by engineering personnel resulted in the determination that the thermocouples were operable. The inspectors found that the basis for this determination, as documented in Engineering Memorandum 112182, did not include any technical justification to support the conclusion. Subsequently, the inspectors contacted Westinghouse engineers, who provided additional information that was not a part of the original NSAL. Specifically, the actual IR measurements (1.5-2.0 E3 ohms), which pose an operability concern under post-accident conditions, are an order of magnitude less that specified in the NSAL. Only one incore thermocouple at Beaver Valley is in this range, and the technical specification minimum of four thermocouples per quadrant is satisfied. The licensee is continuing to evaluate the data and determine whether additional trending is necessary.

c. Conclusions

Overall, the inspectors concluded that the licensee's operability determination was correct, but poorly documented to support this conclusion.

E4 Engineering Staff Knowledge and Performance

E4.1 Pressurizer Surge Line Inservice Inspection

a. Inspection Scope

The inspectors reviewed the circumstances for which the licensee proposed to submit a relief request for an ultrasonic inspection of the pressurizer surge line nozzle inner radius. This inspection was scheduled to be completed during the current refueling outage.

b. Observations and Findings

The Second Ten-Year In-Service Inspection (ISI) Interval began September 21, 1987, and ends September 21, 1997. The requirements of the 1983 Edition, including the 1983 Summer Addenda, of Section XI of the ASME Code are applicable for the Second Ten-Year Interval for Beaver Valley Unit No. 1. The current refueling outage is the last opportunity to perform the surge line nozzle inspection before the end of the Second Ten-Year Interval. On April 19, 1996, representatives of the licensee contacted the NRC staff to discuss the possibility of submitting and obtaining relief from this UT inspection requirement before the end of the current refueling outage. The licensee staff stated that the performance of this inspection would be a hardship since it would involve occupational exposures of 67.5 person-rem and that other inspections (visual) could offer an adequate level of safety assurance. The high dose is due to the time needed to determinate (and re-terminate) the 79 pressurizer heaters which are in a radiation field of 2-4 Rad/hr. This activity is necessary in order to gain access to the inspection location.

During a telephone discussion of this proposed relief request, the NRC staff identified to the licensee that the current inspection interval may be extended up to 1 year. This extension is in accordance with the provisions of Article IWA 2430 of the 1983 Edition of the ASME Code. Therefore, there was no need to process a possible relief request on a highly expedited basis for the current outage since the inspection could be delayed until the refueling outage currently scheduled for fall 1997 and still meet the requirements of the ASME Code.

The NRC staff expressed concern regarding the lack of timeliness in proposing this possible relief request. If submitted, the relief request would have had to have been processed in approximately 2 weeks or less. The ISI examination was a scheduled inspection and not the result of an expanded scope. The inspectors reviewed the planning for this inspection and noted that the need to determinate the pressurizer heaters was not identified until construction personnel began to remove insulation during week 4 of the outage. Pre-outage planning was unable to accurately determine work scope because this inspection was not accomplished during the first ten year interval. Additionally, when the Unit 2 pressurizer surge line was previously inspected, no interference with the heater wires were encountered. Thus, ISI personnel did not have any historical experience which would have assisted the pre-outage planning. However, the job site was not walked down at the beginning of the outage to determine if any interference would exist. In-service inspection personnel had not prioritized the inspection locations for the construction craft to begin the associated prep work. Electrical maintenance and health physics personnel were not notified of the work scope until April 18.

c. Conclusions

Overall, the inspectors concluded that the licensee's pre-job planning was weak in that it did not timely identify the work scope for access to the inspection location. In-service inspection personnel are currently examining methods to better plan future ISI inspections. Additionally, the licensee's knowledge of the ASME code was incomplete as the NRC identified that an automatic 1-year extension was permitted by the code.

E4.2 Reactor Head Vent System Stress Analysis

a. Inspection Scope

The inspectors reviewed the licensee's identification of a stress qualification error from the original design change which installed the reactor head vent system at Unit 1. This identification resulted from a stress analysis of design change 2162 which added an isolation valve to the head vent system during the current outage.

b. Observation and Findings

An engineering analysis identified that for faulted plant conditions, the piping could be potentially over-stressed due to thermal forces. The original piping stress analysis did not comply with the ASME Section III (NC-3600) code allowable values. The original qualification was performed by Combustion Engineering (CE) as part of the post TMI modifications. The cause of this error was that one pipe support (PS-8) was off-position by 18 inches in the original CE code analysis. The licensee re-evaluated the stress qualification and determined that the head vent system was operable during this period and would have functioned if called upon. This determination was based on the use Generic Letter 91-18, Section 6.13 "Piping and Pipe Support Requirements. Specifically, upon discovery of as non conformance with piping and pipe supports, licensee's may use the criteria in Appendix F of Section III of the ASME code for operability determinations. Since the use of Appendix F code allowable values is only permissible to the next refueling outage, it was necessary for the licensee to restore the system to the original ASME requirements. This was accomplished by the modifications of three pipe supports in accordance with technical evaluation report 10301. This qualification error does not apply to the Unit 2 head vent system.

c. Conclusion

The inspectors found the operability determination to be proper and the corrective actions to be acceptable in resorting the system to the original design code. Additionally, the inspectors concluded that the identification of this error was indicative of a good questioning attitude and excellent knowledge of ASME III requirements.

E7 Quality Assurance in Engineering Activities

E7.1 Engineering Assurance Review of Modifications

a. Inspection Scope

The inspectors reviewed two reports issued by the Engineering Assurance (EA) group of the Nuclear Engineering Department (NED). The reports document the EA analysis of the ECNs and FCNs issued during the Beaver Valley Unit 1 tenth refueling outage (1R10) and Unit 2 fifth refueling outage (2R5).

b. Observations and Findings

The reports document the review by EA of the ECNs and FCNs issued against DCPs for 1R10 and 2R5. The review consisted of a determination of causal factors for the changes, as well as an evaluation of the preparation and processing of the changes. EA concluded that the changes were processed in accordance with the procedures, and without unnecessary delays.

EA determined that 81% of the 1R10 changes were of a technical nature, and related to unexpected field interference or inadequate/inconsistent specifications. Similar conclusions (83%) were reached with regard to the 2R5 changes.

Based on their findings, EA made several recommendations:

- Conduct comprehensive pre-installation walkdowns of design changes whenever possible; and
- Increase attention to detail on the part of engineers and engineering supervisors.

c. Conclusions

The EA review of changes to design change packages identified the cause of the problems and proposed appropriate corrective actions. The proposed actions were adopted by DLC. Based upon discussions with installation personnel (noted in E2.1 above), the inspectors concluded that the field walkdowns and constructability meetings being held have aided in identifying interferences prior to DCP issuance.

E7.2 Engineering Assurance Review of Design Change Process

a. Inspection Scope

The inspectors discussed the results and recommendations of the EA review of the design change process which was conducted March 18-29, 1996. A copy of the report was not available since it had just recently been issued, and NED management had not had the opportunity to review the report and formulate a response to its findings and recommendations.

b. Observations and Findings

The EA review concluded that the major objectives of the modification process improvement project had been accomplished, although some of the functions were not being performed as originally envisioned. The EA noted that the Preliminary Review Committee (PRC) was recommending DCPs for implementation at a higher rate than they are currently being completed. The EA review found that, in some cases, tasks are being conducted to meet a deadline, rather than when they are ready (e.g., incomplete I&TP being presented at constructability review meeting and an ECN being used to complete the package at a later date). In addition, the EA review found that the efficiency of the process is somewhat reduced by the various departments working on different priorities, procurement difficulties, and the maintenance department being unfamiliar with the paperwork regarding installation techniques and standards referenced in the I&TPs.

c. Conclusions

The inspectors concluded that the EA review of the DCP process was a good initiative and developed some excellent findings. In addition, the team provided recommendations to NED management for enhancing the design change process.

E8 Miscellaneous Engineering Activities

E8.1 (Closed) Degraded Grid Relay Setpoints (URI 50-334/91-80-04)

a. Inspection Scope

During the EDSFI conducted in 1991 by the NRC, the team questioned the adequacy of the setpoints of the degraded grid relays. In response to the NRC concern, DLC established interim setpoints based on the 4.16 kV and 480 VAC system voltage drop calculations. These setpoints were considered interim by DLC pending the completion of voltage drop calculations for the 120VAC system. The NRC reviewed the interim setpoints and found them acceptable, as documented in Inspection Report 50-334 & 412/94-10.

The inspectors reviewed the Unit 1 120 VAC voltage drop calculations (8700-E-231 and 8700-E-232) computer outputs, and discussed the calculations and computer program with the responsible engineer.

b. Observations and Findings

The computer program, which performed the calculations, was verified and validated under the DLC software QA program documented in NPDAP 8.16. Inputs included the 480 VAC MCC bus voltages at the degraded grid relay setpoints, conductor sizes and lengths from the cable database, and starting and running currents for the 120 VAC loads. Maximum expected voltages were based on backfeeding the facility through the main transformer during shutdown conditions, with the switchyard at maximum voltage. Minimum and maximum acceptable voltages for each component were based upon manufacturers' documentation, NEMA standards, or testing conducted by DLC as noted below.

DLC determined that minimum starting voltages for many of the 120 VAC motors were not available from the manufacturers, and the NEMA standards only dealt with running voltages. As a result, DLC tested representative sample motors to determine the lowest voltages at which they would start. The tests were conducted on spare motors drawn from stock in the warehouse. The DLC testing determined that the capacitor start motors would start at voltages as low as 45 VAC, while the other motors were determined to need 80 VAC to start.

The calculations indicate that as many as 67 devices in the 120 VAC distribution system could be subjected to voltages above their maximum allowable during an outage while backfeeding the electrical distribution system through the main transformer with switchyard voltage at maximum levels. The majority of the equipment is not normally operated during an outage, and has a potential overvoltage less than 5 volts above maximum. Problem Report 1-96-448 has been generated to document this potential overvoltage condition. The recommended resolution is to change the tap setting from -5.00% to -2.50% for the transformers feeding PNL-AC-E01, -E02, -E03, and -E04. This action would resolve 47 of the potential overvoltage conditions. It could, however, result in voltages lower than specified for 2 components at degraded grid conditions. These two components are voltage regulating transformers which maintain their output voltage within ±1% with the input voltage at ±10%. Due to the regulation of the output, there will be no adverse effects on the nonsafety-related instruments fed by the voltage regulating transformer.

The remaining 20 components were evaluated for the effects of the potential overvoltage condition. With the exception of four relays, DLC judged the components to be acceptable without change. The four relays were originally procured with 110 volt coils to ensure that their operation would not be affected by degraded grid conditions. DLC is evaluating the replacement of the relay coils with higher voltage rated coils under their equivalent replacement process.

c. <u>Conclusions</u>

The interim system settings for the degraded grid relay setpoints, which were reviewed and found acceptable in Inspection Report 50-334/94-10 and 50-412/94-10, will become the final setpoints. The components in the 120 VAC system which were found to be potentially operating outside their recommended ranges, will be dealt with individually, and without changing 4.16 kV system relay settings. This item is closed.

The potential overvoltage condition on the relays is acceptable in the interim due to the overvoltage concern being increased heat generation in the coils which would reduce their life. These relays normally operate within their ratings. These relays were not part of the original open item.

IV. Plant Support (83750, 71750, 81700, 81042)

RI Radiological Protection and Chemistry Controls

R1.1 Refueling Outage Radiation Protection (Unit 1)

a. Inspection Scope

The inspectors reviewed radiological controls implemented in the Unit 1 refueling outage and problem reports relating to radiation protection (RP). The following high-challenge jobs were observed in progress (either remotely, or on location).

- lower reactor vessel inspection (concentrating on lower reactor vessel internals removal and replacement)
- steam generator work (such as: eddy current testing, bowl washes, and thermoluminescent dosimeter tree-studies)

The inspectors made frequent tours of the radiologically controlled areas (RCAs), and discussed RP with supervision and several RP technicians (RPTs). This inspection included tours conducted during backshift and deep-backshift hours.

b. Observations and Findings

ALARA performance on the lower vessel internals removal and replacement was excellent and significantly exceeded expectations. The licensee effectively managed a high-challenge job through extensive pre-planning, excellent briefings, practice runs, water shields, high RPT oversight, high supervision oversight, remote observation, and remote radiation monitoring equipment. ALARA plans were properly implemented by workers. Lower vessel internals removal and re-installation was completed during the fifth refueling outage for Unit 1 for 3.45 person-rem while it was completed for 0.245 person-rem during this outage.

Initial portions of the lower reactor vessel inspection were observed by the inspectors. ALARA plans were properly implemented by workers. Licensee ALARA performance benefited from the ALARA plans implemented during the lower reactor vessel internals removal and from remote tooling.

At the time of the inspection, steam generator work was progressing well from an ALARA standpoint. Work was being conducted in accordance with established ALARA plans. The licensee was effectively managing this work through pre-planning, briefings, shielding, high RPT oversight, supervision oversight, robotics, remote manual tooling, remote observation, and remote radiation monitoring equipment. RP control points were established just outside the steam generator cubicles.

Unrelated to lower vessel inspection and steam generator work activities, the inspectors made the following general observations during tours of the Unit 1 RCA.

- No contamination control inadequacies were noted (other than poor radiation worker practices)

- No problems with labels on storage containers were noted.

- Individuals were wearing the required dosimeters.

- When challenged by the inspectors, workers were aware of the dose rates in their work locations.

c. Conclusions

Implementation of radiological controls in the Unit 1 refueling outage was characterized by judicious controls and proper implementation of plans developed for work in RCAs.

R2 Status of RP&C Facilities and Equipment

R2.1 Radiologically-Controlled Area (RCA) Access Controls

a. Inspection Scope

The inspectors interviewed RP personnel, used the new RCA access control system during the course of the inspection, and observed the flow of personnel through the Unit 1 RCA RP control point.

Two major changes were made by the licensee relative to access control to RCAs. The Unit 1 radiation work permit (RWP) sign in/out desk was moved to the turbine deck. The inspectors reviewed a newly-procured RADDOS electronic dosimeter and RCA access control system.

b. Observations and Findings

The inspectors noted that the Unit 1 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 workers entered or left the Unit 1 RCA.

All individuals entering the RCA were provided with an electronic dosimeter and signed onto a computer-based RWP. The inspectors had the following observations.

- 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.

Thermoluminescent dosimeters remained the primary dosimeter by which the dose of record was assessed and assigned. The electronic dosimeters were being used as a control device.

R2.2 Other RCA Access Controls and Equipment

a. Inspection Scope

The inspectors reviewed Unit 1 Reactor Containment Building (RCB) and high radiation area (HRA) access controls. The inspectors also toured the warehouse where the steam generator mock-ups were kept. The inspectors conducted tours, conducted surveys, and discussed controls with RP supervision.

b. Observations and Findings

The Unit 1 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 RCTs to frisk items as workers left the Unit 1 RCB.

The licensee possessed mock-ups of both the primary and secondary sides of a steam generator. The licensee required that individuals be trained using these mock-ups prior to being involved in work on a steam generator.

Early in the outage, most of the 692' elevation of the Unit 1 RCB was controlled as a HRA. The licensee removed HRA access control requirements to most areas of this elevation. In conjunction with this change, the licensee established more discrete HRAs on the 692' elevation and, in some cases, made these HRAs less accessible through the use of heavy plastic fencing.

During the past refueling outage, the licensee controlled the entire refueling cavity as a locked HRA establishing the locked HRA controls at the cavity personnel ladder. The licensee changed controls to this area by controlling the entire cavity as an HRA at the cavity personnel ladder during this refueling outage. In conjunction with this change, the licensee installed a ladder locking device on the cavity transfer canal personnel ladder and placed locked HRA controls on this ladder.

The licensee procured Eberline PCM-2 whole body friskers. These devices can discriminate Radon daughter products which speeds counting times as compared to the Eberline PCM-1 whole body friskers which are also possessed by the licensee. The PCM-2 stationed at the Unit 1 RCA control point helped to reduce congestion in this area.

R2.3 Conclusions on Facilities and Equipment

The new electronic dosimeter and access control system significantly improved the licensee's ability to provide real-time monitoring of exposures. Access control to the Unit 1 RCA was improved by moving the RWP sign-in/out desk to the turbine desk. The Unit 1 RCB egress/ingress point was well established. The steam generator mock-ups were considered to be a very effective part of the licensee's ALARA program. Improvements in HRA access control were noted.

No degradation of the RP program was evident as a result of changes to facilities or equipment.

R3 RP&C Procedures and Documentation

R3.1 Unit 1 EDG Day Tank Fuel Oil Sampling

a. Inspection Scope

The inspectors verified the valve lineup and reviewed the procedure controlling valve lineups for sampling fuel oil in the Unit 1 emergency diesel generator fuel oil day tanks to determine if they were adequate.

b. Observations and Findings

The valve lineups for sampling from the fuel oil day tanks 1EE-TK-2A and 2B, were described in Chemistry Manual procedure C.M. 1-3.37, Issue 3, Revision 4, effective 6/09/95. The inspectors found that this procedure gave proper guidance for performing valve lineups for this sampling. Valves manipulated for this sampling procedure were independently verified to be in the correct position at the conclusion of the sampling activity. The inspectors found the valves properly aligned.

c. Conclusions

The inspectors concluded that valve lineups for sampling the fuel oil in the emergency diesel generator day tanks were properly controlled.

R3.2 Condensate Receivers Sampling

a. Inspection Scope

The inspectors reviewed the procedure controlling valve lineups for sampling condensate in the auxiliary steam condensate receiver, 2ASS-TK21, to determine if it was adequate.

b. Findings and Conclusions

The inspectors found that Chemistry Manual procedure C.M. 2-3,51, Issue 3, Revision 2, effective 1024/95, gave proper guidance for performing valve lineups for this sampling.

R4 Staff Knowledge and Performance in RP&C

Inspection Scope

The inspectors reviewed worker implementation of the radiological controls during the Unit 1 refueling outage and problem reports relating to radiation protection. The inspectors made frequent tours of the radiologically controlled areas, and discussed radiation worker practices with supervision and several RPTs.

R4.1 General Comments

Poor radiation worker practices were noted by the inspectors and by the licensee. Licensee RP supervision stated to the inspectors that only about half of the craft workers were experienced radiation workers.

Other more minor poor radiation worker practices were noted by the NRC inspectors and licensee in addition to those detailed in sections R4.2 through R4.6 of this report.

R4.2 Observations and Findings - March 27, 1996 Fuel Building Transfer Canal Failure to Communicate Work Scope

On March 27, 1996, an individual was assigned to install temporary lighting in the Fuel Building transfer canal. Neither this individual or his supervisor contacted licensee RP staff prior to beginning work. The individual lowered the lighting string into the canal and subsequently raised it to adjust it. The individual adjusted the lighting string with his bare hand and was later found to be contaminated as he exited the Fuel Building.

Licensee RWP 196-0445, "Temporary Lighting", required that RP be contacted prior to work start so that a briefing or dedicated RP coverage could be provided. The "Work Steps" part of this RWP noted RP coverage frequency and, more specifically, noted that RP was to monitor all items removed from contaminated areas. Licensee HPM Chapter 2, Part 1, subpart C. "General Rules", step 1 requires that radiation workers "Obey posted, verbal, and written health physics instructions. Comply with conditions for access to posted areas. Read, understand, and comply with your Radiological Work Permit." Licensee HPM Chapter 1, Part 1, subpart C. "Responsibilities", step 3.b. requires that "Station supervisors are responsible for ensuring that personnel under their supervision comply with the provisions of the health physics program and for planning work to minimize exposure."

The failure to contact RP staff prior to beginning work to receive a pre-job brief as required by RWP 196-0045 was assessed by the inspectors to be a violation of licensee Procedure HPM Chapter 2, Part 1, subpart C. "General Rules", step 1. The failure of the supervisor to ensure that his subordinate contacted licensee RP staff was assessed by the inspectors to be a violation of HPM Chapter 1, Part 1, subpart C. "Responsibilities", step 3.b. Corrective actions included counseling and expectations on protective clothing use was disseminated through station memoranda. This matter was licensee identified.

R4.3 Observations and Findings - March 29, 1996 Improper HRA Entry

On March 29, 1996, an individual was observed entering a visibly posted HRA on the 692' elevation of the Unit 1 RCB. An RPT was observed to note this action. The RPT had not provided a briefing and removed the individual from the HRA. The RPT then questioned the individual as to the dose rates within the HRA. The individual was not aware of specific dose rates and felt that the briefing that he had received the previous day was sufficient for entry.

The individual had signed onto RWP 196-1009 which allowed access to a HRA after a briefing or if dedicated health physics coverage was provided. The failure to obey the HRA posting and the failure to receive a pre-job brief as required by RWP 196-1009 was assessed by the inspectors to be a violation of licensee Procedure HPM Chapter 2, Part 1, subpart C. "General Rules", step 1 (see R4.2). Corrective actions included review of the improper entry with the individual's peers and significant disciplinary action was imposed on the individual. This matter was licensee identified.

R4.4 Observations and Findings - April 19, 1996, RC-9 Failure to Communicate Work Scope

On April 19, during observations of the maintenance associated with the replacement of RC-9 (reactor coolant drain valve), the inspectors noted that radiological work practices were not consistent with ALARA principles. The total accumulated dose was 2.17 man-rem for the entire scope of work performed. Specifically, the inspectors noted that the workers were not familiar with general area dose rates. On two occasions, an NRC inspector informed the workers that the area they believed to be an "ALARA Zone" was actually a 75 mrem/hr dose rate area. Additionally, the workers on one occasion began to use a "flapper wheel" on the reactor coolant piping in preparation of welding. However, they had not informed the RPT of this activity despite the pre-job briefing in which they were directed to inform health physics if any grinding were to take place. An NRC inspector subsequently contacted an RPT who re-directed a HEPA filter suction and directed that the workers don face shields.

RWP 196-1074, "RC-9 Replacement/718' "C" Cubicle", specifically noted to radiation workers that RP was required to perform surveys prior to welding, cutting, or grinding. The two workers failed to contact RP staff prior to grinding although this had been covered during a job pre-brief and was specifically indicated by the appropriate RWP. The appropriate RWP was assessed by the inspectors to be a violation of licensee Procedure HPM Chapter 2, Part 1, subpart C. "General Rules", step 1 (see R4.2). This matter was NRC identified.

R4.5 Observations and Findings - April 19, 1996, Refueling Floor

On April 19, an RPT identified that a tool check worker, located on the refueling floor of containment, had failed to wear a TLD. The RPT appropriately directed the worker to exit the radiologically controlled area. However, a quality control (QC) inspector intervened and would not allow the tool checker to leave the area until a qualified replacement was available due to concerns with foreign material control requirements. However, this precluded the RPT from invoking his "stop work" activity and resulted in the tool checker continuing to work in the RCA without proper dosimetry. Licensee management counselled the quality control inspector. RP management held discussions with RPTs to re-emphasize their "stop work" authority. This matter was licensee identified.

R4.6 Observations and Findings - April 24, 1996 Improper HRA Entry

On April 24, licensee RPTs identified an instance in which two safety engineers violated high radiation area (HRA) (>100 mrem/hr) access requirements. Specifically, the two engineers descended into the refueling cavity without dose rate meters or a pre-briefing by health physics which would have informed the engineers of the radiological conditions.

The engineers were performing equipment checkouts of the safety gear at the top of the ladder for the refueling cavity. The inspectors noted that the engineers involved appeared to not be aware that the refueling cavity was a HRA because the required posting and rope barrier was on the floor. Another factor which contributed to the engineers lack of awareness of the HRA conditions was their observations of refueling personnel who were continuously entering and exiting the refueling cavity without dose rate meters. These refueling personnel had been previously briefed by other RPTs. The inspectors determined that the engineers were generally aware of the HRA access requirements as they had previously demonstrated proper compliance during an entry into the pressurizer cubicle. A pre-job brief was conducted by the RPT for the work at the top of the ladder. This briefing did not include information about the HRA conditions because the initial job scope did not entail entering an area with dose rates greater than 100 mrem/hour. However, the engineers crossed into the designated HRA under the observation of the RPT who was handing tools to the engineers. This was the first occasion in which the HRA access requirements were violated.

Subsequently, the engineers descended the ladder to the bottom of the refueling cavity for a functional check of the safety equipment without the knowledge of the RPT. The engineers, however, did not notify an RPT of the change in work scope. This was the second occasion in which the HRA access requirements were violated. The safety engineers failed to meet their obligation to notify RP personnel of their desire to change work scope so that they would be informed of the radiological conditions in the new work area. The actual safety consequences of these violations was minimal the maximum dose rate experienced was 37 mrem/hour and a total dose of 6 mrem was accumulated for the entire time the engineers were in containment. At the time of the inspection, the licensee was performing a root cause analysis of this event.

The engineers signed onto RWP 196-1009 which permitted access to a HRA/work area after a briefing or if dedicated health physics coverage was provided. Licensee HPM Chapter 1, Part 1, subpart C. "Responsibilities", requires in step 3.a. that "Health Physics personnel are responsible for conducting the health physics program and assisting personnel in other departments in complying with the provisions of the program."

The failure to contact RP staff prior to changing work scope to receive an updated job briefing on the new work area as required by RWP 196-0045 was assessed by the inspectors to be a violation of licensee Procedure HPM Chapter 2, Part 1, subpart C. "General Rules", step 1. The failure of the RPT to properly brief the safety engineers as they crossed into the designated HRA under the RPT's observation was assessed by the inspectors to be a violation of HPM Chapter 1, Part 1, subpart C. "Responsibilities", step 3.a. This matter was licensee identified.

R4.7 Conclusions

Technical Specification (TS) 6.11, "Radiation Protection Program" states that "Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained and adhered to for all operations involving radiation exposure."

The examples of failure to follow procedures detailed in Sections R4.2, R4.3, R.4.4, and R4.6 of this report constitute a **violation** of licensee TS 6.11 (50-334/96-04-01).

Radiation worker practices was considered to be a weakness.

R6 RP&C Organization and Administration

R6.1 Outage RP organization

a. Inspection Scope

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 inspectors noted that both the licensee and contractor RP staff were well-qualified, experienced, and well-supervised. The inspector was informed by licensee RP supervision that there were fewer (as a percentage) contractor RPT returnees as compared to past outages.

The inspectors also 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 the station to provide more dedicated coverage. The inspectors assessed that there were no areas of the Unit 1 RCAs where RPTs were overly burdened.

c. Conclusions

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

R7 Quality Assurance in RP&C Activities

The inspectors reviewed the November 1995 Quality Assurance (QA) audit of Health Physics and the results of outage observations regarding radiation worker practices. QA identified a weakness with respect to a significant number of personnel contamination events which occurred during the 1995 outages. Thus, the audit recommended increased management oversight of radiation worker practices, especially during the 1996 refueling outages. QA observations during the current outage identified instances of poor radiation worker practices. Additionally, the QA organization determined that the Maintenance Work Standard Surveillance Program was not effective in identifying and correcting poor radiation worker practices. This conclusion was based on the fact that no radiation worker practice deficiencies were identified during the surveillances by maintenance personnel. The inspectors concluded that QA has been in the forefront of identifying weaknesses with radiation worker practices and that QA findings were consistent with NRC findings.

S1 Conduct of Security and Safeguards Activities

S1.1 Inspection Scope

The inspectors reviewed the security program during the period of April 29-May 3, 1996. Areas inspected included: previously identified items; management support and audits; effectiveness of management controls; security program plans; protected area detection equipment; alarm stations and communications; testing, maintenance and compensatory measures; and training and qualification. The purpose of this inspection was to determine whether the licensee's security program met licensee commitments and NRC regulatory requirements.

S1.2 Security Program Plans

The inspectors determined, based on reviews and discussions with security management, that security program plan changes implemented since the last inspection, under the provisions of 10 CFR 50.54(p), did not decrease the effectiveness of the security program.

S2 Status of Security Facilities and Equipment

S2.1 Protected Area Detection Aids

The inspectors conducted a physical inspection of the protected area (PA) intrusion detection systems (IDSs) on May 2, 1996. The inspectors determined by observation that the IDSs were installed and maintained as described in the plan.

S2.2 Alarm Stations and Communications

The inspectors observed Central Alarm Station (CAS) and Secondary Alarm Station (SAS) operations, and verified that the alarm stations were equipped with the appropriate alarm, surveillance, and communication capabilities. Inspectors interviews of CAS and SAS operators found them knowledgeable of their duties and responsibilities. The inspectors also verified that the CAS and SAS operators were not required to engage in activities that would interfere with assessment and response functions, and that the licensee had exercised communications methods with the local law enforcement agencies as committed to in the Plan.

S2.3 Testing, Maintenance and Compensatory Measures

The inspector's review of testing and maintenance records for security-related equipment confirmed that the records committed to in the Plan were on file, and that the licensee was testing and, in general, maintaining systems and equipment as committed to in the Plan. A review of these records, as described below, indicated that repairs were being completed in a more timely manner than previously, and that a priority status was assigned to each work request.

During NRC Inspection Report 95-20, conducted in November 1995, the inspectors identified a weakness in the testing and maintenance program concerning the backlog of security equipment work requests that dated back to 1993. Specifically, 76 security equipment work requests existed which included 24 associated with closed-circuit television (CCTV) repairs. The backlog was considered significant especially because failure to repair the CCTV cameras could affect the alarm station operator's ability to assess the cause of an alarm accurately.

The actions implemented by the licensee to resolve the weakness appeared to be adequate. Those actions included weekly meetings between security and maintenance supervision to discuss the status of security equipment work requests and to establish a schedule to effect repairs. During this inspection, the inspectors determined, by a review of security maintenance records, that the backlog of open security equipment work requests had been reduced. As of May 2, 1996, 40 work requests existed, which included work requests that had been generated since November 1995. Of the 40 work requests, 15 were associated with CCTV repairs. However, 20 of 24 CCTV work requests identified in November 1995, were completed and replacement parts were on order for the completion of the remaining four repairs. Priority repair efforts were being placed on equipment that required compensatory measures by members of the security force. The inspectors discussed the noted improvements with security management and emphasized the importance of maintaining the initiative and rapport with maintenance.

The inspector's review of the use of compensatory measures found it to be appropriate and minimal. This was apparently due to the priority repair efforts by the maintenance group to problems that require compensatory measures.

S5 Security and Safeguards Staff Training and Qualification

On May 2, 1996, the inspectors met with the security training staff and discussed the training program enhancements made since the last inspection conducted in November 1995. These included improvements to the present weapons stress course and the procurement of training aids to add realism during contingency response training.

The inspectors observed weapons training on May 2, 1996, which consisted of weapons familiarization and target acquisition. The instructors did an excellent job controlling the drills and the range was controlled in a safe manner. Additionally, the inspectors interviewed several security force members (SFMs) and determined that, based on the SFMs responses to the inspector's questions, the training provided by the security training staff was effective.

S6 Security Organization and Administration

S6.1 Management Support

Management support for the physical security program was determined to be excellent. This determination was based on the inspector's review of various program enhancements made since the last inspection, which was conducted in November 1995. These included completion of the vehicle barrier system installation, procurement of training aids for tactical response training, and modifications to the security computer to improve speed and reliability.

P7 Quality Assurance in Security and Safeguards Activities

P7.1 Audits

The inspectors reviewed the 1996 Nuclear Quality Services (NQS) audit of the security and access authorization (AA) programs conducted between January 26- March 11, 1996 (Audit No. BV-C-96-02). The inspectors determined that the audit was conducted in accordance with the licensee's NRC-approved physical security plan (the Plan). To enhance the effectiveness of the audit, the audit team included an independent security specialist.

The audit identified four findings requesting a written response concerning protected area access control of personnel and packages, quarterly preventive maintenance battery testing for the security emergency power supply system, improper implementation of controls for licensee designated vehicles, and two small sections of the vehicle barrier system were installed in a position which slightly exceeded the allowable spacing requirement.

The inspectors determined that the noted findings were not indicative of programmatic weaknesses but would enhance program effectiveness. The inspectors also determined, based on discussions with security management and a review of the responses to the findings, that the corrective actions were effective.

The inspector's review concluded that the audit was comprehensive in scope and depth, that the findings were reported to the appropriate levels of management and that the programs were being properly administered.

P7.2 Effectiveness of Management Controls

The inspectors determined that the licensee had controls for identifying, resolving, and preventing security program related problems. These controls included the implementation of formalized self-assessment programs by the licensee and by the security contractor, the conduct of annual quality assurance (QA) audits using independent security expertise, and ongoing oversight by licensee shift supervision. A review of documentation applicable to these programs indicated that initiatives continue to minimize security performance errors and to identify and resolve potential weaknesses.

P8 Miscellaneous Security and Safeguards Issues

P8.1 (Closed) License Event Report (LER) 96-S01-00: On January 2, 1996, the licensee determined that a contract employee had falsified information on his application for unescorted access, which resulted in the licensee reporting the event under the provisions of 10 CFR 73.71(c). The inspectors reviewed the circumstances surrounding the event, and the licensee's response and determined the LER to be a minor issue for which the licensee took appropriate action and was closed.

L1 Review of UFSAR Commitments

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 compares plant practices, procedures and/or parameters to the UFSAR descriptions.

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.

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 May 17, 1996, including reference to findings presented earlier in the report period by resident specialist inspectors. The licensee acknowledged the findings presented. No proprietary information was identified as being included in the report.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

T. Noonan, Division Vice President, Nuclear Operations and Plant Manager
S. Jain, Division Vice President, Nuclear Services
B. Tuite, General Manager, Nuclear Operations
C. Hawley, General Manager, Maintenance Programs Unit
R. Vento, Manager, Health Physics
R. Brosi, Manager, Nuclear Safety
L. Freeland, Manager, Nuclear Engineering
K. Ostrowski, Manager, Quality Services Unit

NRC

P. Eselgroth, NRC
D. Brinkman, NRR

INSPECTION PROCEDURES USED

IP 37550: Engineering
IP 37551: Onsite Engineering
IP 40500: Effectiveness of Licensee Controls
IP 57080: NDE Review and Work Observation
IP 61726: Surveillance Observations
IP 62703: Maintenance Observation
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 81042: Security Testing and Maintenance
IP 81700: Physical Security
IP 83750: Occupational Exposure
TI 2515/111: EDSFI Follow-up

ITEMS OPENED, CLOSED AND DISCUSSED

Opened

50-334/94-04-01 - Violation

Closed

50-334/91-80-04
50-412/94-25-01
50-334/95-13-02
50-412/95-13-02

LER 96S01-00

Discussed

None

LIST OF ACRONYMS USED

AA	Access Authorization
AOV	Air Operated Valve
CAS	Central Alarm Station
CCR	Component Cooling Water
CCTV	Closed Circuit Television
CE	Combustion Engineering
DLC	Duquesne Light Company
ECR	Employee Concern Resolution
HPM	Health Physics Manual
HRA	High Radiation Area
IDI	Inside Diameter
IDS	Intrusion Detection System
IR	Insulation Resistance
ISI	Inservice Inspection
LER	Licensee Event Report
MSP	Maintenance Surveillance Procedure
MWR	Maintenance Work Request
NQS	Nuclear Quality Service
NSAL	Nuclear Safety Advisory Letter
NSS	Nuclear Shift Supervisor
OST	Operational Surveillance Test
PA	Protected Area
PDR	Public Document Room
PM	Preventive Maintenance
PSI	Pre-Service Inspection
QC	Quality Control
QCRP	Quality Concern Resolution Program
RCA	Radiological Controlled Area
RCB	Reactor Containment Building
RCB	Reactor Containment Building
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RP	Radiation Protection
RPT	Radiation Protection Technician
RWP	Radiological Work Permit
RWP	Radiological Work Permit
SAS	Secondary Alarm Station
SFM	Security Force Member
SRO	Senior Reactor Operator
SSPS	Solid State Protection System
TER	Technical Evaluation Report
TS	Technical Specification
UT	Ultrasonic

Appendix X

Documents Reviewed for Engineering Inspection

Appendix X

Documents Reviewed for Engineering Inspection

Problem Report #	SSFI Corrective Action #	Description
1-95-549	TST-008-3	Charging pump discharge pressure in Technical Specifications is non-conservatively low (2311 psig vs. 2397 psig used by Westinghouse in accident analysis)
1-95-554	DCE-009-2	Complete testing of the Auto SI Block function is not being performed
1-95-555	OPS-14-1	SI Auto Recirculation output relays are not being properly tested

Modifications

DCP 2097

ECN 2097-1	EM 111500	
ECN 2097-2		
ECN 2097-3		

DCP 2173

ECN 2173-1	FCN 2173-1	EM 111991
ECN 2173-2	FCN 2173-2	EM 111995
ECN 2173-3	FCN 2173-3	EM 111897
ECN 2173-4	FCN 2173-4	EM 111815
ECN 2173-5	FCN 2173-5	
ECN 2173-6	FCN 2173-6	
ECN 2173-7	FCN 2173-7	
ECN 2173-8	FCN 2173-8	
ECN 2173-9	FCN 2173-9	
ECN 2173-10	FCN 2173-10	
ECN 2173-11 through 15		
ECN 2173-17		

DCP 2151

ECN 2151-1	FCN 2151-1	EM 111984
ECN 2151-2	FCN 2151-2	EM 111815
ECN 2151-3		EM 111228
ECN 2151-4 through 13		

DCP 2162

ECN 2162-1

DCP 2163

ECN 2163-1	OI NCD-2163-01	
ECN 2163-2 through 9		

Appendix X

Documents Reviewed for Engineering Inspection

(continued)

Spent Fuel Hoist Malfunction

PR 1-96-263
PR 1-96-296
TER 10258
TER 10262
Night Orders Entry for March 30, 1996